Technical Submission
To
Alberta Government
Royalty Review Panel

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1.0 Executive Summary

The Canadian Society for Unconventional Gas, (CSUG), a non-profit, industry funded organization is making this written submission to the Alberta Government Royalty Review Panel to present the Society's views relating to the current Alberta Government royalty structure on natural gas production. This submission represents a more in depth analysis of the oral presentation made to the Royalty Review Panel on May 22 in Calgary. While CSUG's mandate is to advocate for the responsible development of all unconventional gas in Canada, in this submission, the focus will be restricted to Natural Gas from Coal (NGC).

Conventional gas production from Western Canada has seen a steady decline since its peak levels in 2001. To offset this decline, the oil and gas industry is becoming more reliant on unconventional gas sources such as tight gas and natural gas from coal. By the end of 2006, it was estimated that as much as 5 Bcf/d (141 Mm^3/d) of natural gas was derived from these unconventional sources. NGC development accounts for nearly 1 Bcf/d (28 Mm^3/d) or approximately 6% of Alberta's daily production. As more NGC projects are developed, this total is expected to rise to nearly 2 Bcf/d (56 Mm^3/d) within the next five years.

NGC exploration in Alberta began nearly 25 years before commercial success was achieved. Through these early years, numerous companies experimented with a variety of techniques for NGC reservoir stimulation and production. It was not until 2001 that commercial success was achieved, in part through a strengthening of commodity prices, but also from the application of shallow gas drilling and innovations in completion technologies as well as multi-seam commingled production. By December 31, 2006, over 10,000 wells had been drilled for NGC of which over 9000 were for the Horseshoe Canyon type shallow gas play. This number could grow to over 40,000 wells when the total resource, estimated at greater than 125 (currently 20Tcf or 0.56Tm^3 recoverable). In addition, companies are beginning to focus on the two other significant NGC resource plays in the province, the deep Mannville Formation and the shallow Scollard/Ardley coal measures. Both of these NGC bearing horizons have a potential for a combined resource potential in excess of 375 Tcf (10.5 Tm^3).

Over the past 20 years, a significant amount of exploration work has been completed on the Horseshoe Canyon coals and in doing so, industry has developed an understanding of the unique reservoir properties of these coals that make them economically attractive (for example the lack of water in the reservoirs). Technological innovations were developed to commercially produce these coals and the development of the Horseshoe Canyon NGC potential has since proceeded on a relatively straight forward basis. In contrast however, exploration and production of the Mannville and Ardley resource plays appear to have significantly greater challenges, primarily due to high variability of reservoir properties and significantly higher capital costs.

NGC development bears significantly different risk profiles as compared to conventional gas developments. In the early stages of exploration, there is a much higher risk for conventional gas in defining where the potential reservoirs may exist whereas there is a very good understanding of where the coal resources lie within the subsurface of the province. Risk increases dramatically with NGC developments however in the development and production stages. The industry is relatively young with a short production history. Long term sustainability of resource production and ultimate recoverable resources are not as well known at this stage, yet NGC developments commonly require significantly higher levels of capital investment with longer cost recovery times due to the lower productivity of individual wells. The result of these higher levels of risk in conjunction with higher capital costs and longer investment payout times, place NGC developments as having a high price sensitivity and in many cases a requirement for a threshold price greater than current market prices to become or remain economic.

A detailed analysis of NGC supply costs, conducted by the Canadian Energy Research Institute on behalf of CSUG, indicates that under the current royalty and taxation structure in the province of Alberta, NGC developments in the Horseshoe Canyon play require a market price threshold of ~$6.00/mcf to be economic. This is based upon an 8 well/section configuration which would allow ~45% of the Gas In Place to be recovered. Lower well density of 1 well per section would have a much lower price threshold, but recovers only 11% of the Gas In Place. For Mannville and Ardley plays, the commodity price threshold necessary for economic projects, while not included in the CERI analysis, would probably be even higher, due to the higher capital costs for development.

In most NGC developments, where wells have a lower productivity, some compensation is achieved through the existing low productivity royalty structure. The average NGC well from the Horseshoe Canyon play produces at a rate of 135 mcf/d (3.8 m^3/d) and pays an average royalty rate of 15%. In NGC developments where horizontal wells or multi-lateral wells produce gas from a single wellbore, but with multiple production legs or paths, the average production rate is significantly higher and thus does not qualify for the royalty reduction. This poses a challenge for some of the newer type plays such as the Mannville or Ardley coals where horizontal drilling may be necessary to overcome reservoir conditions in order to achieve commercially economic rates. Higher capital and ongoing operational costs are incurred in developing these new resources, yet the existing royalty structure does not compensate for these additional costs.

The development of unconventional gas in United States (which now accounts for 40% of total gas production) was built upon a foundation of tax incentives commonly referred to as the “Section 29 Tax Credit”. This federally administered program along with the establishment of an industry funded research and development organization (GRI) provided the incentives for the exploration of the nation’s unconventional resources and the development of technology that enabled these resources to be produced in an economical manner. Alberta has not as yet implemented any similar royalty plan specifically for the development of the province’s unconventional gas resources, and existing NGC developments must compete with conventional gas supplies even though capital costs are higher and return on capital investment is over a longer time. Lower productivity wells do benefit from the sliding scale royalty structure that is currently in place, but this process doe not take into account the higher capital costs that NGC wells are burdened with.

The NGC industry faces a number of challenges that must be recognized and addressed when considering royalty restructuring for the province of Alberta. These challenges:

- Development of Technology
- Higher Capital Cost
- Price Sensitivity
- Risk and Sustainability
- Lack of Royalty Incentives

are currently placing a significant burden on the viability of continued NGC development, particularly in the deep Mannville and Scollard/Ardley resource plays. While industry has managed to develop the Horseshoe Canyon play effectively, this was accomplished primarily at a time of high commodity prices where the impact of these challenges was diminished. Long term growth and sustainability of the NGC industry continues to be affected by these challenges, particularly high capital cost and commodity price sensitivity. At current prices, many of the NGC projects that were initiated in 2006 are marginally economic or have been suspended until economics improve.

Conventional gas production in Alberta is slowly dropping as the maturity of the basin is making it more difficult to find and replace these resources.. There is a broad recognition by industry and the Province that the development of Alberta’s unconventional gas resources is critical for long term sustainability yet there are currently no royalty incentives for the development of this resource.. As the Royalty Review Panel considers the current royalty structure, particularly with natural gas, the Canadian Society for Unconventional Gas respectively requests that consideration be given to maintaining the sliding scale low productivity royalty scheme that is currently in existence and that consideration be given to providing additional royalty incentives that would encourage the development of technology that could be applied to the more challenging NGC resources within the province as well as the developing tight gas and shale gas resources.

2.0 Background of Canadian Society for Unconventional Gas

The precursor to CSUG was the Canadian Coalbed Methane Forum, an association of corporations and individuals interested in coalbed methane (CBM) resources in Canada. The forum was active for over 10 years and created an Annual Coalbed Methane Conference to use as a tool to collaborate with peers and discuss needed technology and research to aid in the development of the resource. In and around the year 2000, the oil and gas industry had shown increased activity and interest towards CBM resource development and its technologies. It became apparent that the Forum needed to become a more formal entity in order to effectively provide more broad-based information sharing and technology development.

In April 2002, the Canadian Society for Unconventional Gas (CSUG) was formed as a recognized formal society registered in the Province of Alberta. The Society was created to support the exploration and development of Canadian unconventional gas resources and focus energy and resources on all forms of unconventional gas, including:

- Coalbed Methane or Natural Gas from Coal (NGC)
- Tight Gas Sands
- Shale Gas
- Gas Hydrates

Shortly after becoming a registered society, the need to provide communication and education to the public and other stakeholders became apparent. In response to this need, CSUG developed a communications plan with the following primary objectives:

- Educate the media about unconventional gas sources and provide them with the materials necessary for them to more accurately report the facts and issues surrounding the resource.
- Increase the dialogue between the unconventional gas industry and the federal and Alberta and British Columbia governments.
- Increase the amount, and improve the quality and consistency, of communications with stakeholder groups in both Alberta and BC.
- Improve and streamline communication to/from CSUG member companies.
- Design and introduce new administrative communication elements to reduce response time and increase effectiveness of all communication activities.

Mission

To facilitate the factual and collaborative exchange of unconventional gas knowledge and challenges among government, regulators, industry and public stakeholders for the exploration and production of the resource in an environmentally sensitive and economical manner.

3.0 Natural Gas Supply and Demand – The Need for Unconventional Gas

The Western Canada Sedimentary Basin contains significant hydrocarbons, the majority of which are located in the province of Alberta. Oil and gas exploration has been an important part of Alberta's growth and economy since the major discovery of gas at Royalite #1 near Turner Valley in the early 1900's. Since that time, the energy industry has extensively explored and developed the hydrocarbon resources of this province so that today, Western Canada is considered a mature oil and gas basin where oil and gas pools tend to be smaller and more difficult to locate. Figure 3.1 illustrates the trend of average peak production rates for new gas wells in Alberta and it can be seen that average peak well production has decreased from a high of 750 mcf/d (21 m^3/d) in 1995 to less than 250 mcf/d (7m^3/d) in 2005. This trend has also led to a significant increase in the number of wells that are drilled on an annual basis (figure 3.2) to maintain and increase production from the Province.

Conventional gas production from the Western Canada Sedimentary Basin is estimated to have peaked in 2001, (figure 3.3) and the basin is experiencing a steady decline in conventional natural gas production. Alberta contributes approximately 13 Bcf/d (368 Mm^3/d) of natural gas to Canada's supply. This daily production rate is also estimated to be declining by an average 0.8 Bcf/day (23 Mm^3/d) on an annual basis. As the gap increases between conventional gas supply and increasing gas demand, companies are looking towards unconventional gas supplies to offset the differential (figure 3.4).

Alberta is fortunate that most of the unconventional natural gas resources of the Western Canada Sedimentary Basin lie within the provincial boundaries. These resources (figure 3.5) represent a huge resource that will become increasingly important for the sustainability of the province's natural gas industry. To date most of the development activities in unconventional gas have focused on natural gas from coal (NGC) and tight gas. In the last two years, there has also been an increased interest in the development of Canada's shale gas resources, although commercial production has not been demonstrated in this gas source. Unconventional gas accounts for nearly 25 percent of Canada's natural gas production and in Alberta, NGC represents as much as 6 percent of natural gas supply (figure 3.6). It is projected that unconventional gas could account for as much as 50% of Canada's gas supply by 2025.

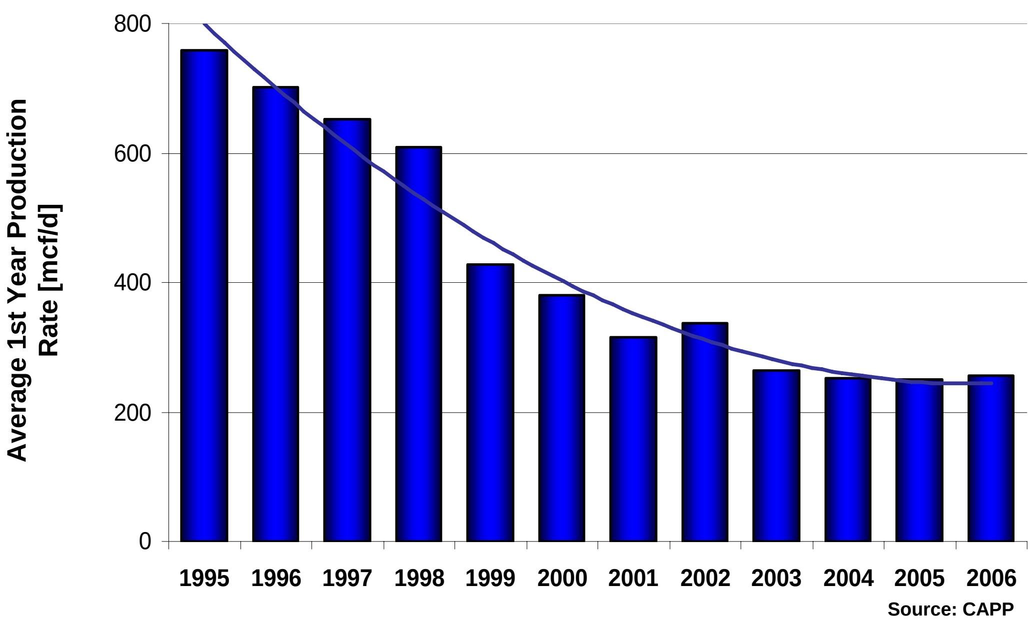


Figure 3.1: Average natural gas well production

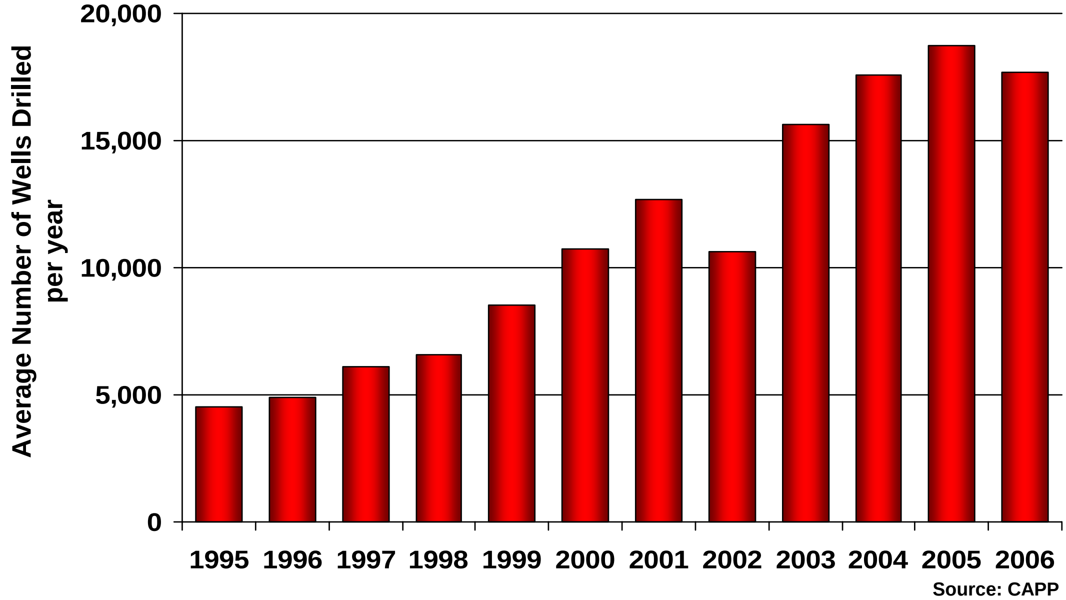


Figure 3.2: Number of gas wells drilled annually

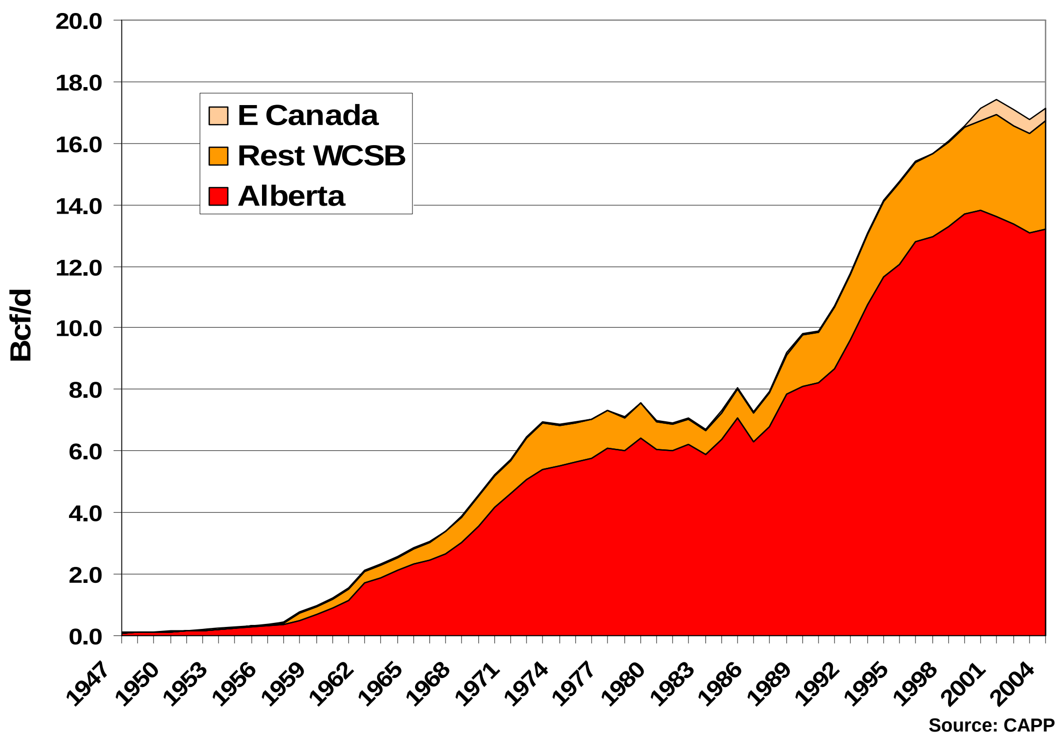


Figure 3.3: Peak of Conventional Gas Production in Canada and Alberta

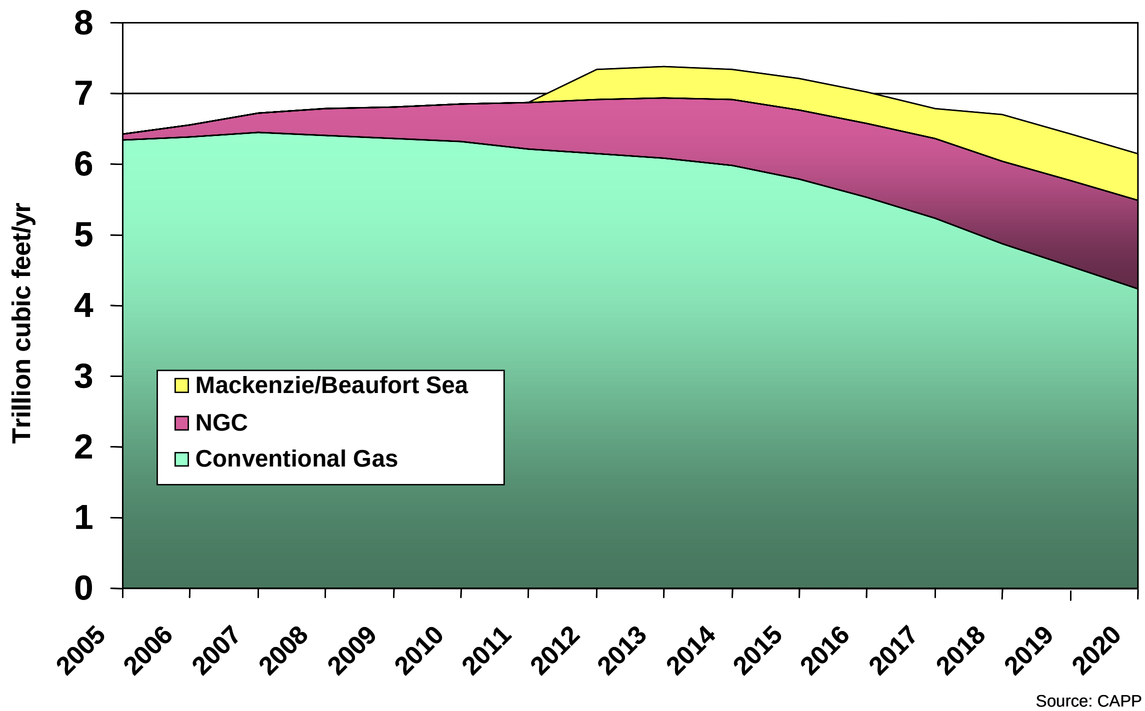


Figure 3.4: Decline in conventional natural gas production

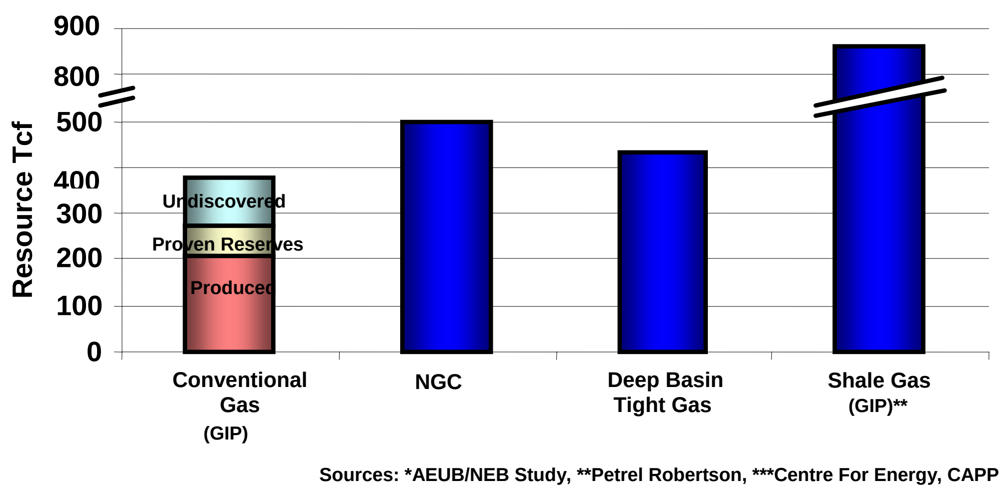


Figure 3.5: Distribution of Unconventional Gas Resources in Alberta

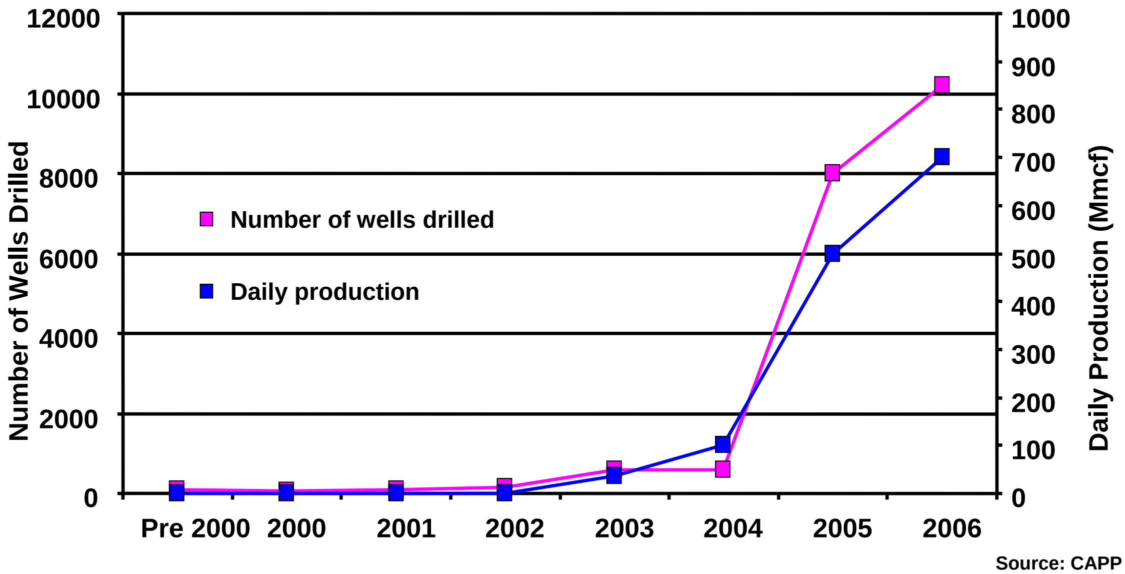


Figure 3.6: Number of NGC Wells Compared to NGC Production

4.0 Royalty Review Submission Terms of Reference

The Canadian Society for Unconventional Gas has a mandate to advocate for the responsible development of all forms of unconventional gas. There are similarities between all types of unconventional gas sources, be it tight gas sands or natural gas from coal. In all cases, the resources tend to be more difficult and costly to produce which not only adds to the economic sensitivity of the project as well as a higher risk profile of developing the resource. For this written submission to the royalty review panel, the society has determined that the focus should be on natural gas from coal (NGC) and the remaining section of this report will focus on this specific resource type.

5.0 Distribution of Natural Gas from Coal (NGC) Resources

The province of Alberta is fortunate to contain the majority of the NGC resources within the Western Canada Sedimentary Basin. Total Gas In Place is estimated at nearly 500 Tcf (14 Tm^3) although recoverable resources are expected to be substantially smaller. Over 75 Tcf (2 Tm^3) are projected to be recoverable but this number may grow substantially with the application of new and emerging technologies. Current gas production from NGC exceeds 750 Mmcf/d (21 Mm^3/d) and is expected to grow to over 1 Bcf/d (28 Mm^3/d) by the end of 2008. NGC resources are found within 3 major coalbearing intervals in the province: Mannville Formation, Horseshoe Canyon/Belly River Formations and Scollard/Ardley , (figure 5.1). Additional NGC resources in the Alberta foothills and mountain regions have been identified, but little exploration and no development has occurred in these regions as yet. Each of these intervals, excluding the mountain and foothills resources, will be discussed briefly below in terms of distribution, resource potential and stage of development.

5.1 Horseshoe Canyon/Belly River Formations

The Horseshoe Canyon/Belly River formations are located in south central to eastern Alberta and represent approximately 25 % of the provinces defined NGC resource potential, but over 90% of current NGC production. Current production is estimated to be greater than 750 Mmcf/d (21 Mm^3/d) and over 9000 boreholes have been drilled since 2001 to develop this resource, (figure 5.2). The major production “fairway” is situated east of Highway 2 in the Calgary to Edmonton corridor. Ultimately it is projected that in excess of 40,000 wells may be completed in this horizon and gas production could exceed 1.5 Bcf/day (42.5 Mm^3/d).

Prior to 2001, extraction of NGC did not exist as a commercial venture in Alberta, but, with the application of co-mingling of production streams from individual coal beds along with development of unique nitrogen fracture stimulation techniques, this resource has been able to be economically produced. Unlike most coal gas reservoirs throughout the world, the shallow Horseshoe Canyon/Belly River "play" is essentially dry and the coals do not require de-watering prior to gas production. Although typical per well production is less than 150 mcf/day (4 m^3/d), these rates are deemed economic because of the application of shallow gas drilling technology and commonly "economy of scale" multi-well project development. Production history is in its infancy and ultimate recovery rates are unknown at this stage of development.

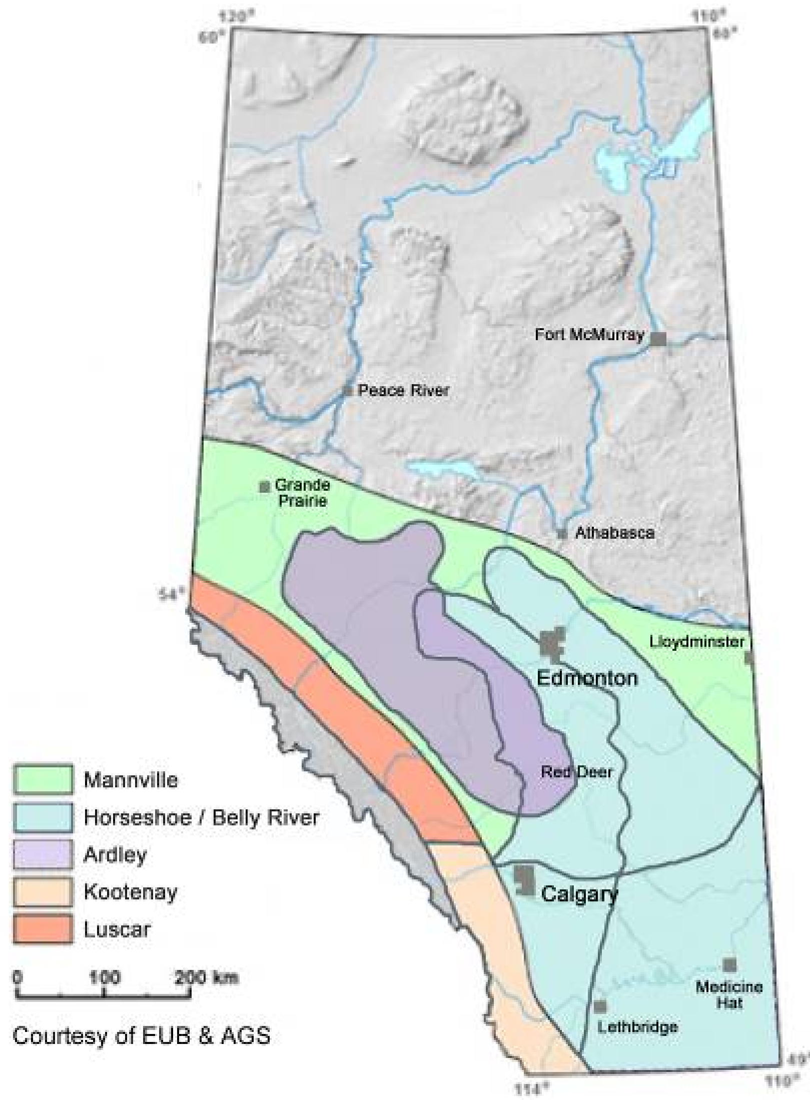
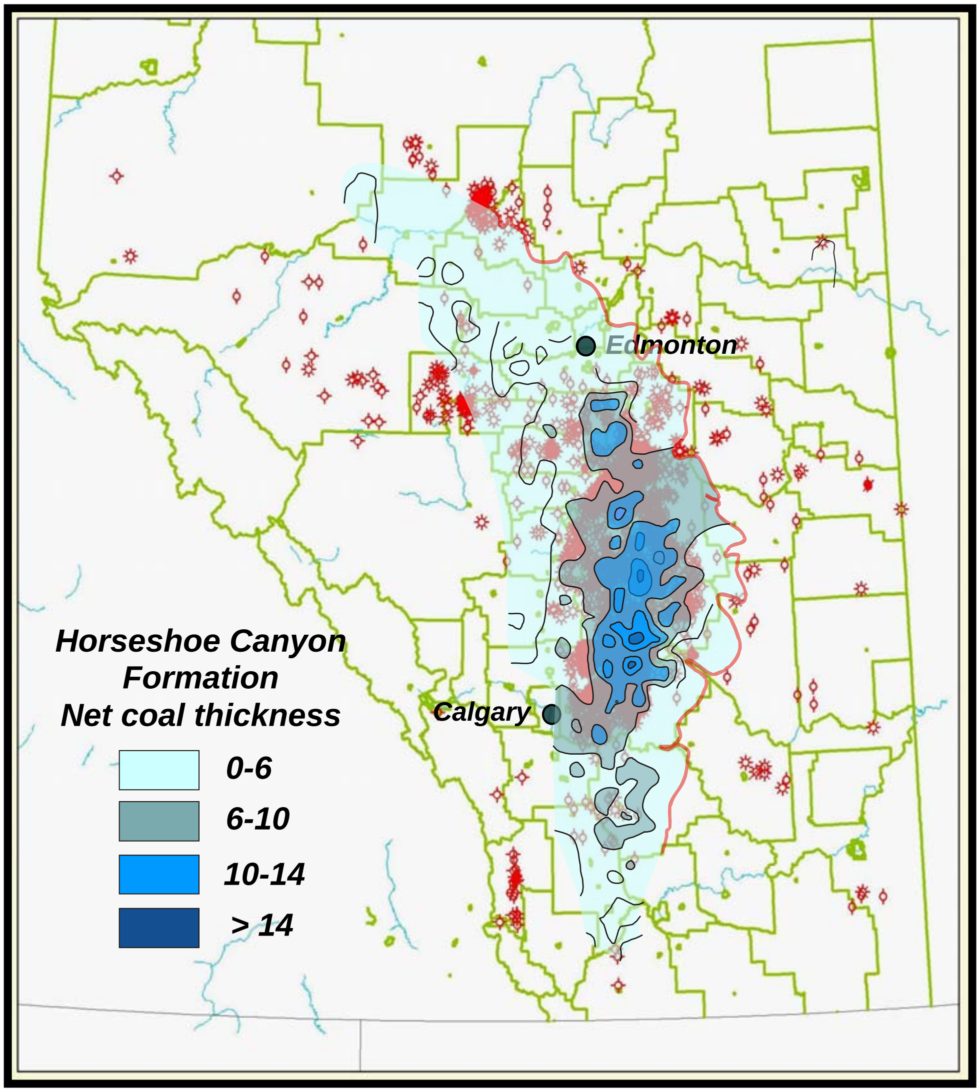


Figure 5.1: Distribution of Alberta's NGC Resources



Source: CSUG

Figure 5.2: Distribution of Horseshoe Canyon NGC well activity

5.2 Mannville Formation

The Mannville Formation contains up to 60% of the defined NGC resources in the province and is currently producing an estimated 80 Mmcf/d (2 Mm^3/d). The coals of the Mannville Formation are widespread throughout the southern half of the province, are generally at a greater depth than those of the Horseshoe Canyon or Scollard/Ardley and tend to require de-watering prior to gas production. The coal reservoirs tend to have a higher gas storage capacity and present an attractive resource for NGC. To date exploration and development activities have been focused primarily in the Fort Assiniboine region northwest of Edmonton and in the Nevis area, east of Red Deer. By the end of 2006, 822 wells had been drilled to test and potentially produce NGC from the Mannville Formation. Mannville NGC wells tend to be higher cost to drill and complete although horizontal wells do, in most cases produce at higher volumes. Monthly operation costs tend to be higher due to the requirement to produce and dispose of formation water. The application of horizontal and multi-lateral drilling technology has allowed commercial gas production rates to be achieved by a number of companies in single well scenarios. Only the development at Fort Assiniboine by Trident and Nexen can be classified as a commercial success on a project scale.

While there has been increased level of activity for NGC within the Mannville Formation, the drilling and completion techniques that have been tested have not demonstrated repeatability throughout the basin. Coal quality and reservoir characteristics are highly variable throughout the province and significant exploration and experimental projects will be required before NGC production becomes routine.

5.3 Scollard / Ardley Coal Measures

The Scollard Formation which contains the laterally persistent Ardley coal zone accounts for roughly 15% of the defined NGC resources in the province and less than 1% of current production. The Scollard Formation is located in the west-central portion of the province extending westwards from the Red Deer River to the foothills. The Ardley coals extend from outcrop in the east to greater than 600 m in the west and display a wide variability of reservoir properties. Production testing that has been completed has encountered coals that are dry, coals that produce saline water and wells that produce "fresh water". The low production rates associated with the Ardley coals and the challenge of fresh water production and associated governmental regulations that deal with this issue have led to less exploration investment by industry. Although development is restricted in the short term, the Scollard/Ardley coals represent a significant NGC resource and have the potential to play an important role in Alberta's unconventional gas supply in the future.

5.4 Conventional and NGC Well Comparison

While drilling for hydrocarbons, whether it be conventional or unconventional gas resources, has relied on proven techniques that have been developed over the past 60 years in Western Canada, the more challenging reservoirs that are now the target of industry commonly require the application of new or modified technology. In NGC development, the drilling of the wells has drawn heavily on the technology of conventional shallow gas exploration, particularly for the Horseshoe Canyon play where coil tubing drilling and program drilling have been successfully adapted. For the deeper Mannville Formation wells, the borehole diameter is generally larger to accommodate downhole pumping equipment. There appears to be a trend towards horizontal wells and multi-lateral configurations in order to optimize the intersection of the coal reservoir and also to minimize the surface footprint. Geosteering requirements and prevention of formation damage during the drilling process remain significant challenges due to the variability and compressibility of the reservoir (coal).

In the shallow Horseshoe Canyon wells of the Alberta plains, multiple seams must be completed and stimulated to achieve economic rates of gas production. In comparison, most conventional gas reservoirs are completed in a single zone. In multi-zone completions, each individual coal seam is selectively fracture stimulated, and then the gas flow is co-mingled with other zones and produced through a single wellhead. Commonly 15 to 30 zones are independently stimulated is a single wellbore, dependent on the number of coal seams present.

In vertical deep Mannville NGC wells, this type of multi-seam stimulation has been used, although sand water fracturing techniques appear to be preferred over nitrogen due to the presence of water into the coal seam. Specialized fluids are often required to minimize the formation damage to the coal seams. Upon completion of the stimulation, the well usually requires downhole tubing and pumping equipment to enable the coal(s) to be de-watered. Coupled with surface facilities such as a pumpjack and surface water handling systems, the capital and operational costs are significantly higher than for conventional gas wells.

Horizontal wells that are being drilled to capture gas from the coals in either Mannville or Scollard/Ardley require specialized geo-steering equipment to minimize out of zone transigence. Coal is a difficult rock type to effectively drill horizontally and the additional geo-steering requirements commonly lead to significantly higher drilling and completion costs. Upon completion of the well, installation and maintenance of downhole equipment can be particularly challenging due to the problems of borehole stability and migration of borehole solids. Downhole pump replacements that are commonly required due to invasion of coal fines can cost upwards of $100,000 to $200,000 per change, and depending on the geotechnical aspects of the reservoir, these changes can occur as frequently as every 6 months.

In order for wells to produce NGC at optimal rates, the wellhead pressure needs to be extremely low (commonly less than 5 psi). In order to achieve this, surface facilities commonly require a dedicated low pressure gathering system that consists of larger diameter pipe and additional compression. In the Horseshoe Canyon play two or in some cases three stages of compression are required to meet regional sales pipeline pressure requirements.

Compression is a critical component of NGC production and adds significant capital costs to any development. In deep Mannville wells, the need to de-water the coals to enable gas production requires a second set of tubing and surface facilities to capture and dispose of produced formation water.

6.0 History of Development and Industry Trends

The development of NGC as a viable source of natural gas in Alberta has been an ongoing process of learning and developing technological applications for nearly 25 years (figure 6.1). In the early 1980's and 90's, numerous companies undertook experimental wells or multiple wells to test the producibility of the coals from the major coal-bearing formations. Commercial success was not achieved until 2001 when the joint venture of MGV Energy and PanCanadian Petroleum were successful in obtaining economic volumes of gas from the shallow Horseshoe Canyon Formation coals.

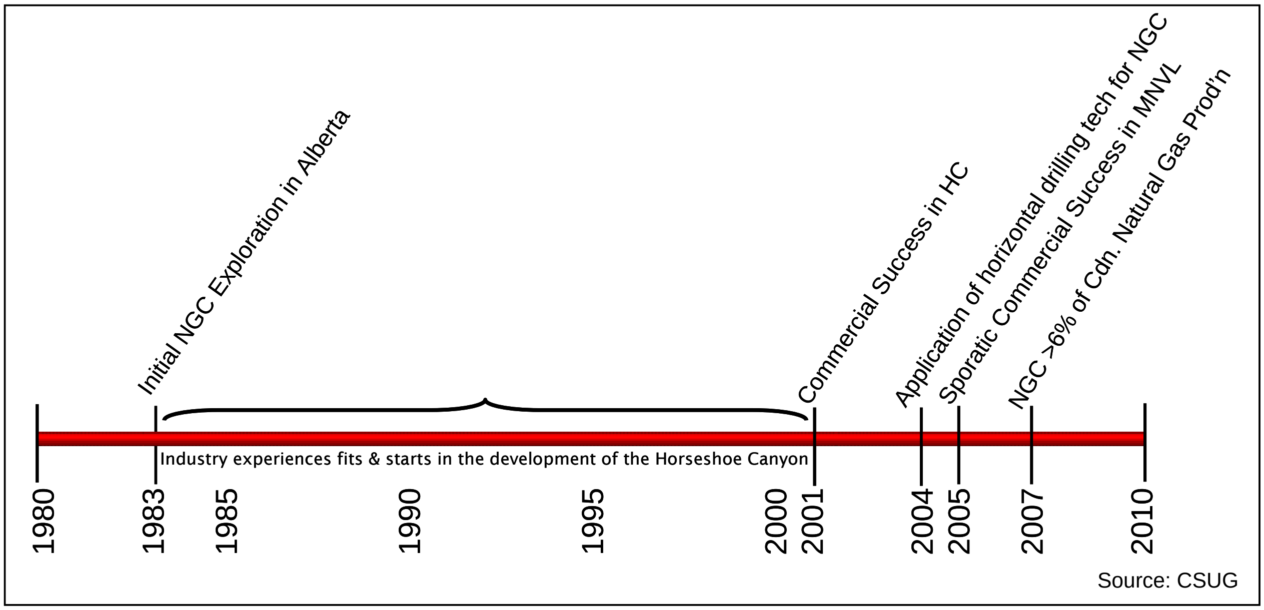


Figure 6.1: Timelines of NGC Development in Alberta

Since that time, industry has invested well over $1 billion in developing this resource play and at the end of 2006 there were over 50 companies producing NGC gas from this formation. The critical technological factors that led to the successful development of this resource can be summarized as:

- Development and application of nitrogen multi-seam fracture stimulation
- Co-mingling in an individual wellbore of the gas flow from multiple stimulated coals zones
- Development of reservoir models and understanding to characterize the coals in terms of gas in place and production profiles
- Application of shallow gas drilling technology to lower drilling costs and minimize surface footprint
- Recognition of the need for dedicated low pressure gathering systems to optimize wellbore productivity
- Develop project economics and economy of scale operations (a manufacturing process for drilling and completion services)
- Recognition that success for the production was based upon a resource play type of mentality

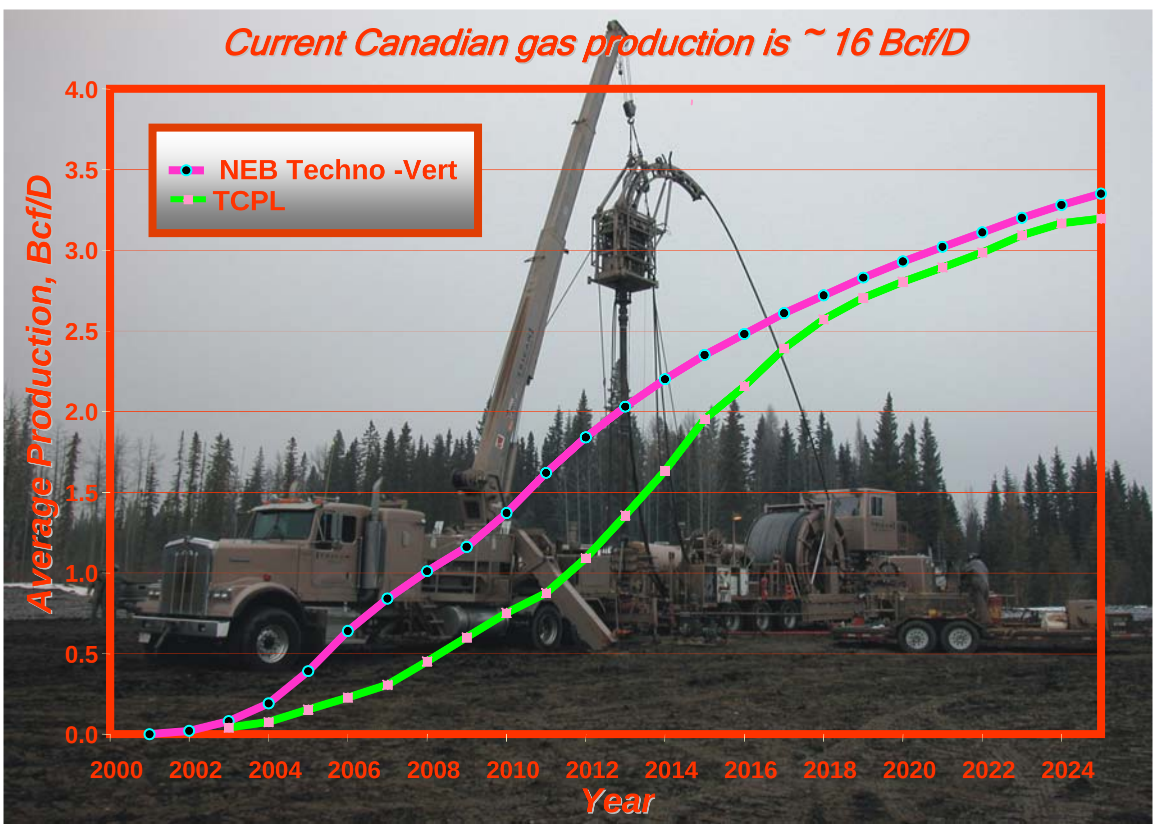
By the end of 2006, over 9000 wells had been drilled for the Horseshoe Canyon play and currently an average of 200 wells per month are continuing to be licensed. Commonly well density is based upon 4 wells per section (160 acre spacing) and in some areas, 8 wells per section (80 acre spacing) are considered necessary to effectively recover the gas resources. While long term production profiles and ultimate recovery have been estimated, actual production is less than 5 years old.

In contrast, commercial development of the deeper Mannville Formation coals did not occur until 2005 with the announcement of the success of the Trident/Nexen joint venture in the Fort Assiniboine area northwest of Edmonton. These two companies collectively has spent hundreds of millions of dollars of risk capital to; acquire land, evaluate coal seam reservoir parameters, experiment with drilling, completion and pumping technology through a number of test pilot projects. While this project is currently producing at ~ 80 Mmcf/d (2 Mm^3/d), the transfer of technology and repeatability to other locations in the province is doubtful.

The Mannville Formation has been a much more difficult resource to develop. The coal seams lie at greater depth and require de-watering to allow the gas to flow to surface. After a number of years of experimentation, the joint venture companies determined that the most effective method for gas extraction was through the drilling and completion of horizontal wells, either single legs or multi-lateral configuration. These types of wellbores, while contributing significantly higher production volumes, are substantially more expensive to drill and complete. The ongoing production of formation water that requires subsurface disposal also contributes to higher operational costs as compared to the Horseshoe Canyon resource play.

The Scollard/Ardley resource play is similar to the Horseshoe Canyon Formation in that shallow gas drilling and completion technology can be applied. Unlike the Horseshoe Canyon play however, early exploration results suggest that the production of NGC and formation water is highly variable, ranging from coals that are essentially dry to coals that contribute large volumes of water. Water quality is also highly variable ranging from fresh (<4000 ppm TDS) to saline (>30,000 ppm TDS). Insufficient development has occurred to date for industry to have a good understanding of what controls the water and gas variability. At present less than 100 wells have been completed in the Scollard/Ardley horizon and industry is for the most part reticent to explore in this region until Alberta Environment guidelines dealing with water disposal have been clarified.

Figure 6.2 illustrates the growth in NGC production and projections of ultimate production levels for Canada. Most of the NGC development is projected to occur in Alberta through the continued development of the Horseshoe Canyon and deep Mannville formations.



Source: NEB/TCPL/CAPP

Figure 6.2: NGC Production and Projected Ultimate Volume Contribution

7.0 Risk and Sustainability

In any hydrocarbon development, there exists elements of risk associated with (1) actually finding the resource in the subsurface, (2) being able to extract the resource at economic rates and (3) achieving sufficient productivity of the resource over a period of time to allow capital costs to be recovered and the company to achieve a reasonable rate of return on that capital investment. NGC exploration and development faces the same challenges with additional pressure on cost recovery.

The distribution of coal in the subsurface is reasonably well understood in the province mainly due to the large number of wells that have penetrated through the coal-bearing rock package in the search for other horizons thought to contain oil and gas. Conventional oil and gas drilling data have not however quantified the recoverable resource size or properties. Even though the distribution of the coal may be known, the amount of gas in storage, reservoir saturation or properties that affect reservoir permeability or performance are unknown. Companies that are planning to develop NGC resources usually undertake extensive testing of the reservoir in advance of commercial development to quantify these reservoir characteristics. This pre-development testing can take anywhere from several months to several years, depending on the complexity of the reservoir.

In addition to the requirement for determination of local reservoir conditions, coal reservoirs tend to be heterogeneous leading to high variability in producibility, not only from gas field to gas field but also from well to well within individual fields. This variability often prevents the application of analog reproducibility.

In the case of the Horseshoe Canyon shallow NGC developments, application of nitrogen fracture stimulation of multiple seams in each wellbore has proven to be successful and is currently the preferred method for reservoir stimulation. Well performance after stimulation is however highly variable which has significant impact on project economics and long term sustainability. Current recovery expectations in the Horseshoe Canyon are relatively low and at present marginal areas of the Horseshoe Canyon resource distribution area are not being developed. Additional technical improvement and investment will be required if more of this resource is to be captured.

For the deep Mannville Formation coals, there is an additional risk element associated with determining the most effective method for drilling and stimulating the wells. Horizontal and multi-lateral well configurations appear to have resulted in the greatest improvement in reservoir production, but there are numerous engineering aspects associated with these types of drilling techniques that influence wellbore producibility. Development of the Mannville NGC resources is still at a very early stage and optimal or preferred drilling and completion procedures have not been identified as yet. Early indications are that the Mannville NGC projects and test wells, albeit not developed to the same level as the Horseshoe Canyon, display similar production variability associated with heterogeneous reservoirs. Evaluations to date suggest that a variety of techniques and practices will need to be applied to different areas through the province where the Mannville coals are prospective.

Figure 7.1 illustrates relative risk profiles associated with the development of NGC reservoirs in comparison to conventional gas reservoirs. While there is a greater risk in conventional gas exploration to actually finding the potential reservoir compared to NGC, there are much greater risks in developing the gas resources in NGC projects because of the significant variability in reservoir properties, particularly with respect to reservoir damage due to drilling and stimulation. Other risks that relate to the higher cost of capital that translates into a longer time for return of capital and risk of sustainability of production. The risk values in Figure 7.1 are meant to reflect a relative term and not considered to be absolute.

NGC production in Alberta has had a short existence with commercial production from the Horseshoe Canyon Formation beginning in 2001 and Mannville Formation developments occurring in 2005. As such, neither development type has had an extensive production history in order to determine long term sustainability. In most cases, the production history is too short to define decline rates and ultimate recoverability of NGC for individual wells and pools. Companies are still proceeding with exploration and development of the province’s NGC resources (with perhaps the exception of the Scollard/Ardley coals). This continued exposure of high risk capital by the industry for a product where sustainability is still undetermined is a direct response to the increased demand for unconventional gas because of the decline of conventional production. Essentially, companies are exploring for and developing unconventional gas resources because they are unable to meet their production volumes and growth projections by relying solely on conventional production.

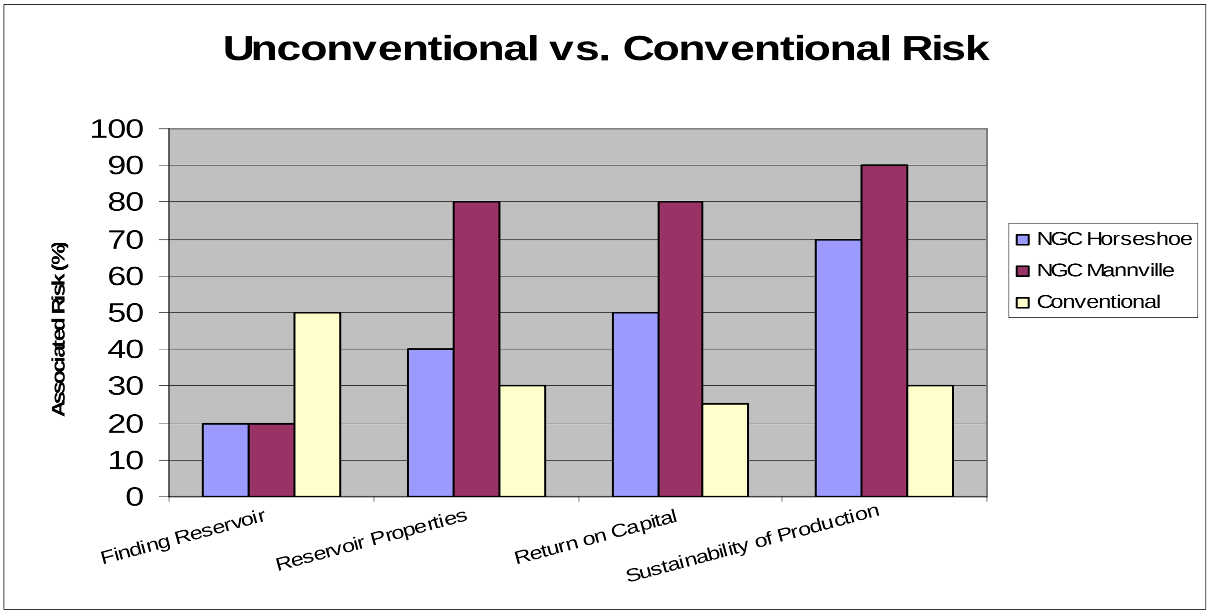
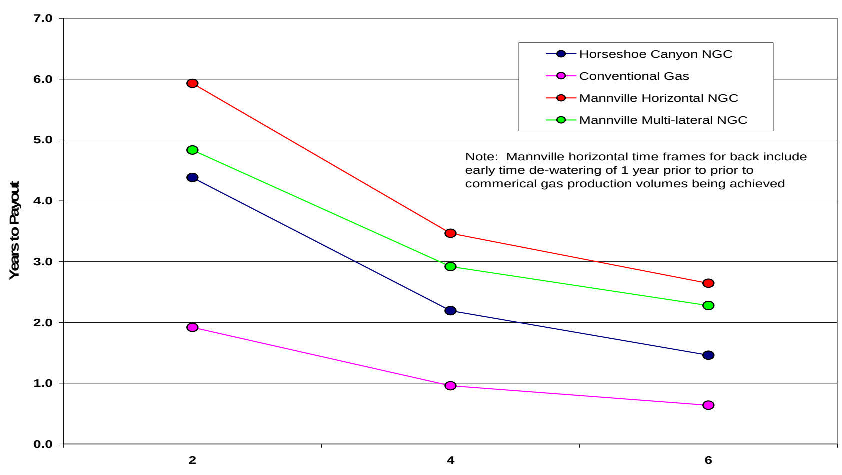


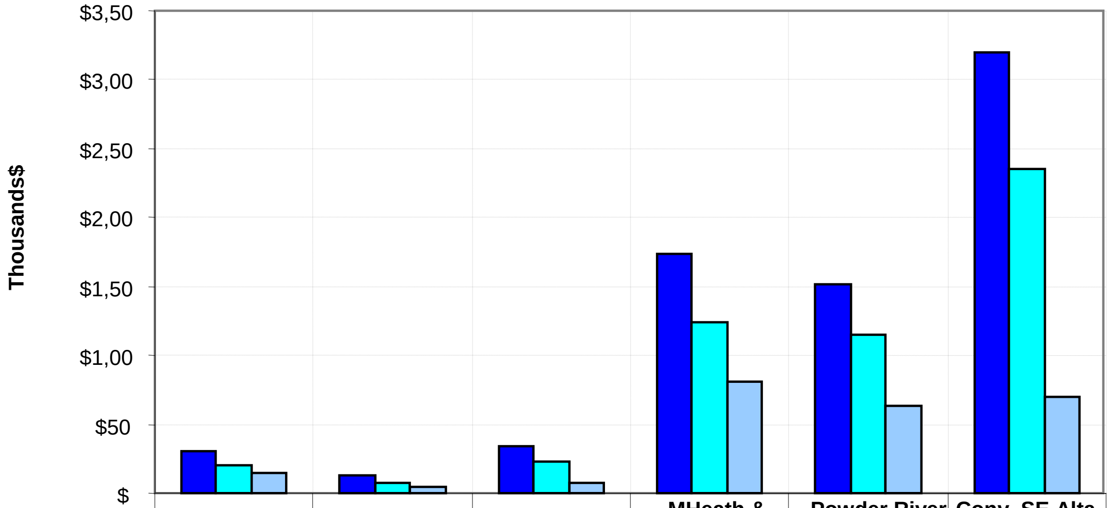
Figure 7.1: Unconventional vs. Conventional Risk **Source: CSUG**

Investment of risk capital and sustainability are of greater significance with NGC developments because of the generally lower production rates for wells, relative to the high capital costs. The result is a longer time frame for project payout and return on investment. Figure 7.2 illustrates cost to develop typical NGC wells along with payout time periods based upon various natural gas netback prices. The netback price value represents the difference between market price for natural gas and incurred costs of production including royalty, tax and operation costs. The differential reflects a net $ value irrespective of specific market price for natural gas. It can be seen from this table that in comparison to the average production rate for conventional gas wells (250mcf/d or 8m3/day), NGC developments have a significantly longer payout time, particularly when gas prices are low. This extended timeframe provides a higher level of risk on capital investment when long term sustainability and overall ultimate recovery of gas per well is not understood. In Figure 7.3, a comparison of after tax cash flow for NGC wells as compared to the Powder River Basin NGC developments in United States and shallow conventional gas wells in southeast Alberta reveals a significant disparity between NGC in Alberta and other shallow gas type developments. The difference between the Horseshoe Canyon case I and 2 is that in Case 2, the number of wells is double. The graph reveals that even at low gas prices (in this case $5.00/mcf), NGC developments appear to be marginally economic.



Source: CSUG

Figure 7.2: Comparison between Years Payout and Gas Price Netback



	HSC Case 1	HSC Case 2	Mannville	MHeath & Associates	Powder River CBM	Conv. SE Alta PSAC
Bta	$30	$12	$33	$1,7	$1,5	$3,1
Ata	$20	$7	$23	$1,2	$1,1	$2,3
ATax (less	$14	$4	$7	$80	$63	$69

Note: Federal Corporate Income Tax @ 21%, Alberta Corporate Income Tax @ 11.5%, BTax = Before tax net cash flow w/ royalties, ATax = BTax less Federal & Provincial CIT, ATax(Less royalty) = ATax less Royalties

Source: CSUG

Figure 7.3: Comparison of After Tax Cash Flow of NGC wells to conventional gas wells

8.0 Supply Costs for NGC Development

To date most of the NGC development that has occurred in the province has focused on the shallow Horseshoe Canyon Formation. This NGC resource play region contains numerous gas fields operated by a variety of companies ranging from small operators to large integrated corporations. An integral part of the royalty review process consists of understanding what the true exploration and development costs are for NGC. The following section summarizes the supply cost estimates from the CERI study "Costs of Natural Gas from the Coal Seams of the Plains Region of Alberta" completed in March 2006. This study estimates the supply costs of natural gas from the Horseshoe Canyon and Belly River coals (referred to as "Horseshoe"). The study also provides some insight into the natural gas from coal (NGC) volumes that might be economically recoverable in the near term and establishes baseline market prices that are necessary for NGC to be economical.

8.1 Data Sources

Historical data for the production performance of producing NGC wells were obtained from the public information files of the Alberta Energy Utilities Board (AEUB). For supply cost calculation the historical performances were projected over the producing lives of the wells using reservoir simulation techniques. The reservoir simulation software of the Computer Modeling Group (CMG) was used for this purpose.

Capital costs for NGC well licenses, permits, infrastructure, drilling and completion are based on data provided in annual reports from the Petroleum Services Association of Canada (PSAC). Operating cost information is from reports of the Alberta Department of Energy (ADOE) and AEUB and from technical publications. Information for the calculation of royalties and taxes is from the publications of ADOE. The cost and fiscal information is listed in Table 8.1.

Table 8.1: Cost and Fiscal Inputs to Supply Cost Calculations Horseshoe Canyon

	Value	Data Source
Capital Costs		
Licences/permits/infrastructure ($/well)	25,000	PSAC data
Well Drilling and Completion ($/well)	275,000	PSAC data
Flow line to gathering system ($/well)	60,000	ADOE/EUB reports
Water Disposal System ($/well)	0	ADOE/EUB reports
Annual Operating Costs		
Fixed well cost ($k/well/yr)	7.00	ADOE/EUB reports
Variable well cost ($/mcf)	0.05	ADOE/EUB reports
Gather/compress/process ($/mcf)	0.51	ADOE/EUB reports
Water disposal variable cost ($ per bl)	0.00	ADOE/EUB reports
Abandonment & reclamation ($k/well)	20.00	ADOE/EUB reports
Fiscal Inputs		
Inflation rate (%)	2.0	Assumed value
Base royalty rate (%)	15	ADOE publication
Marginal royalty rate (%)	40	ADOE publication
Select price ($/GJ)	1.29	ADOE publication
CEE write-down on declining balance (%)	25	ADOE publication
CDE allowance limit (%)	30	ADOE publication
Federal tax rate (%)	21	Assumed Value
Provincial tax rate (%)	10	Assumed Value

Table 8.1 shows that total capital cost for a Horseshoe vertical well on average amounts to $360,000. This cost is adjusted for coal zone depth for each of the fields examined but does not include compression costs which could add an additional $40,000 per well. Note also that because the Horseshoe Canyon developments are predominantly dry, no capital costs have been allocated for water disposal. In contrast, Mannville Formation coal developments usually require de-watering to optimize gas production and recovery and would carry an additional burden of water disposal costs over and above the increased costs of drilling.

8.2 Supply Cost Results

Undiscounted supply costs are estimated for all aspects of a one well per section drill spacing and are presented in Table 8.2. These numbers are simply the total cost for the component over the life of the project divided by the total production over the life of the project. From this table can be seen that outside of the Fenn Big Valley development, the costs range from $2.62/mcf to $4.39/mcf with royalties, taxes and return on capital (10% assumed) accounting for 37 to 44%. The table illustrates the relative magnitudes of the components of the supply cost. Capital costs range from $0.64 per mcf at Gayford to $2.61 per mcf at Fenn-Big Valley. Operating costs range from $0.93 per mcf at Gayford to $1.72 per mcf at Fenn-Big Valley. Returns (10% real) range from $0.53 per mcf at Gayford to $1.94 per mcf at Fenn-Big Valley.

In Table 8.3 total supply costs are estimated by field for vertical well spacing of 1 to 8 wells per section. The fields are listed in order of increasing depth of the coal seams. Supply costs increase with increasing density of drilling and generally tend to increase with increasing coal zone depth. As the industry increases its understanding of productivity and gas recoverability from the Horseshoe Canyon play, it appears that optimal well spacing to maximize gas recovery will probably be either 4 to 8 wells per section. The supply cost for eight vertical wells per section ranges from 4.78 $/mcf at Gayford to 7.45 $/mcf at Rowley. Fenn Big Valley is excluded as supply costs appear to be abnormally high because of low gas content and relatively low net pay. It is assumed from the results that a base price of $6.00/mcf would be required to essentially cover all supply costs, but would yield only about a 10% return on capital.

Table 8.2: Horseshoe Supply Cost Breakdown ($2006/mcf - one well /section)

	Fenn-BV	Rowley	Gayford	Entice	Strathmore	Irricana	Wimborne
Licenses/permits/infrastructure	0.25	0.08	0.06	0.07	0.09	0.09	0.06
Drilling and completion	2.36	0.74	0.58	0.84	0.99	1.06	0.72
Water disposal system	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total capital cost	**2.61**	**0.81**	**0.64**	**0.91**	**1.07**	**1.15**	**0.78**
Well operations/A&G	0.98	0.37	0.33	0.51	0.60	0.68	0.50
Gather/compress/process	0.55	0.55	0.55	0.55	0.55	0.55	0.55
Water disposal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Abandonment & Reclamation	0.20	0.06	0.05	0.06	0.07	0.07	0.05
Total operating cost	**1.72**	**0.98**	**0.93**	**1.12**	**1.22**	**1.30**	**1.10**
Royalties	0.48	0.27	0.26	0.31	0.34	0.36	0.33
Taxes	0.94	0.26	0.26	0.40	0.48	0.51	0.38
Return (10 % real)	1.94	0.53	0.54	0.83	1.00	1.07	0.81
Total supply cost	**7.69**	**2.86**	**2.62**	**3.57**	**4.10**	**4.39**	**3.41**

Source: CERI

Table 8.3: Supply Costs at Alternate Well Spacings ($2006/Mcf)

Wells per section	**1**	**2**	**4**	**8**
Fenn-Big Valley	7.69	9.74	12.82	18.90
Rowley	2.86	3.67	4.96	7.45
Gayford	2.62	3.05	3.63	4.78
Entice	3.57	3.88	4.23	5.05
Strathmore	4.10	4.35	4.63	5.43
Irricana	4.39	4.62	4.87	5.63
Winborne	3.41	3.76	4.30	5.55
Horseshoe average	**3.52**	**3.83**	**4.19**	**5.10**

Source: CERI

The supply cost calculation assumes that the field gate price is equal to the supply cost over the life of the project. Consequently royalties and taxes have a variable impact on the supply cost because tax and royalty payments are a function of prices and costs.

8.3 Supply Cost Curves for Horseshoe Canyon NGC

Horseshoe resource supply cost curves for one and eight wells per section are displayed in Figure 8.1. The curves assume that the fields analyzed make up a representative sample of the resource as a whole. The resources are stacked in ascending supply cost order. There is an optimum spacing for each reservoir and therefore the order in which the reservoirs stack depends upon the spacing. For example, Rowley is the first in the series at one well per section but last at eight wells per section. This reservoir has relatively high permeability and one well per section efficiently drains the reservoir, making additional wells uneconomic. The curve labeled “One Well per Section” is the least cost curve available from the results of the study. It illustrates that with a spacing of one well per section the average supply cost amounts to about $3.52 per mcf with a range of $2.62 to $4.39 per mcf. While this is the least cost strategy, twenty-year recovery of the resource is very low (on average approximately 11 percent of the in place resource). The curve labeled “Eight Wells per Section” illustrates that with a spacing of eight wells per section the average supply cost amounts to about $5.10 per mcf with a range of $4.78 to $7.45 per mcf. In this case the twenty-year recovery of the resource amounts on average to about 45% percent of the in place resource. Figure 8.1 demonstrates that, on average, stable field gate prices greater than about $6.00 per mcf will be required for efficient exploitation of the resource.

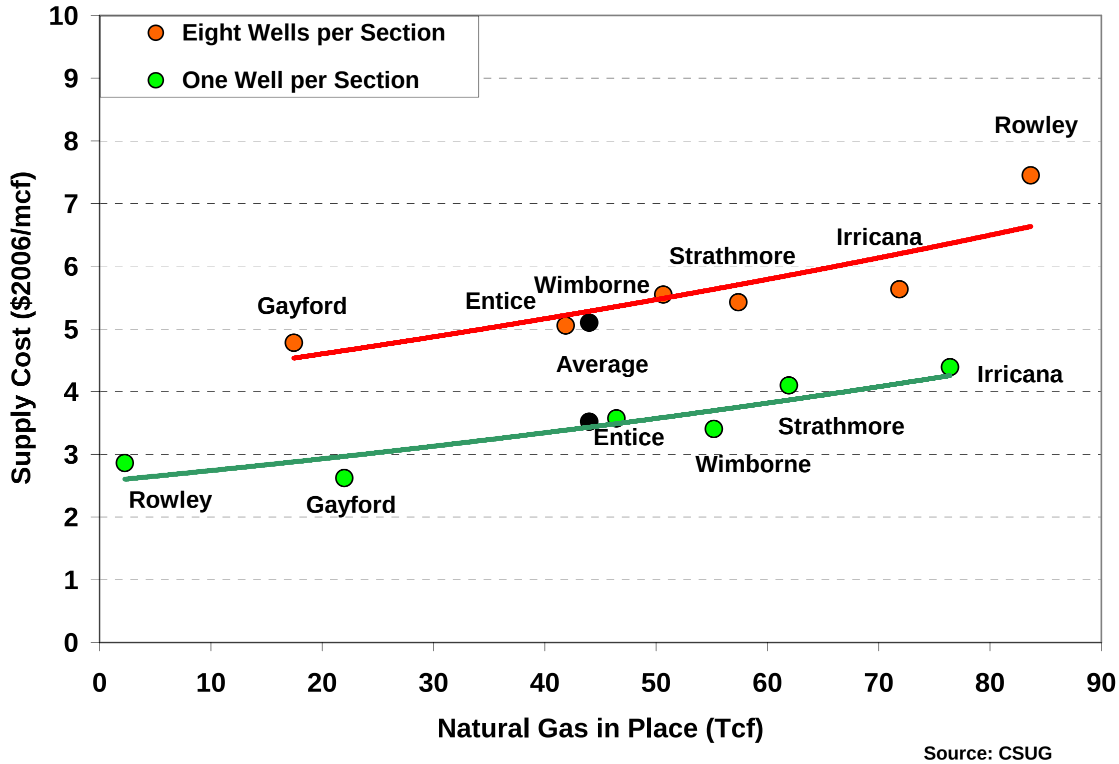


Figure 8.1: Supply Cost Curves for Horseshoe NGC

9.0 NGC and the Current Royalty Structure

Most vertical wells producing NGC in Alberta tend to have lower production rates in comparison to conventional gas wells. As such the wells are currently governed by the low production royalty calculation format. This system accounts for low productivity wells and effectively charges a sliding scale royalty based upon productivity. The royalty ranges from 5% to a cap of 30% at a production rate of 600 mcf/d (17 m^3/d) as illustrated in figure 9.1. NGC production for Horseshoe Canyon coals averages 135 mcf/day (3.8 m^3/d) or lower although there are a number of wells that do produce at significantly higher volumes. Based upon this average, the royalty payable would approximate 14-15%. While the Horseshoe royalty rate, because of the sliding scale, is similar to shallow gas type conventional production capital costs, are significantly higher particularly when additional cost burdens associated with NGC development are added (ie. baseline water well testing, pressure control well data, desorption control well data and ongoing pressure monitoring wells).

In contrast, horizontal wells particularly multi-laterals that produce from the Mannville Formation coals, generally have a higher production rate and would be paying the maximum royalty rate of 30%. When the deep, wet Mannville NGC projects are examined, because of the co-mingled production from the horizontal or multi-lateral legs of the wells is produced from a single wellbore, the gas volume is treated as coming from a single well and thus usually does not benefit from the sliding royalty scale as the co-mingled volume is usually greater than the 600 mcf/d (17 m^3/d) threshold even though the productivity from each leg of the horizontal well is below the threshold volume. When capital costs for this type of NGC development are considered, significant higher costs are incurred with the drilling and completion of the wells. There are also additional costs for water collection and disposal, desorption control well data, pressure monitoring of wells and increased operation costs on an ongoing basis. It must be stated however that this scenario applies only where the horizontal well/multi-lateral drilling and completion technique is successful. In many of the horizontal Mannville wells, production is low at the beginning as the coal seams are de-watered. As the reservoir pressure declines, gas production increases. Under this scenario, the variable royalty rate is effective. The challenge that exists with the Mannville type drilling and completions is the extensive time required to dewater the wells, given that most of the capital costs were expended in the early stages of the project. In Figure 9.1, the example presented illustrates a successful single horizontal well and does not reflect the production profiles across the basin or within the project area. Experience (pers. comm.) has shown that even within the Fort Assiniboine project there is wide variability in production volumes from each individual horizontal leg or lateral. Collectively the commingled gas flow in most cases exceeds the 600 mcf/d (17m^3/d) threshold, but repeatability is a challenge.

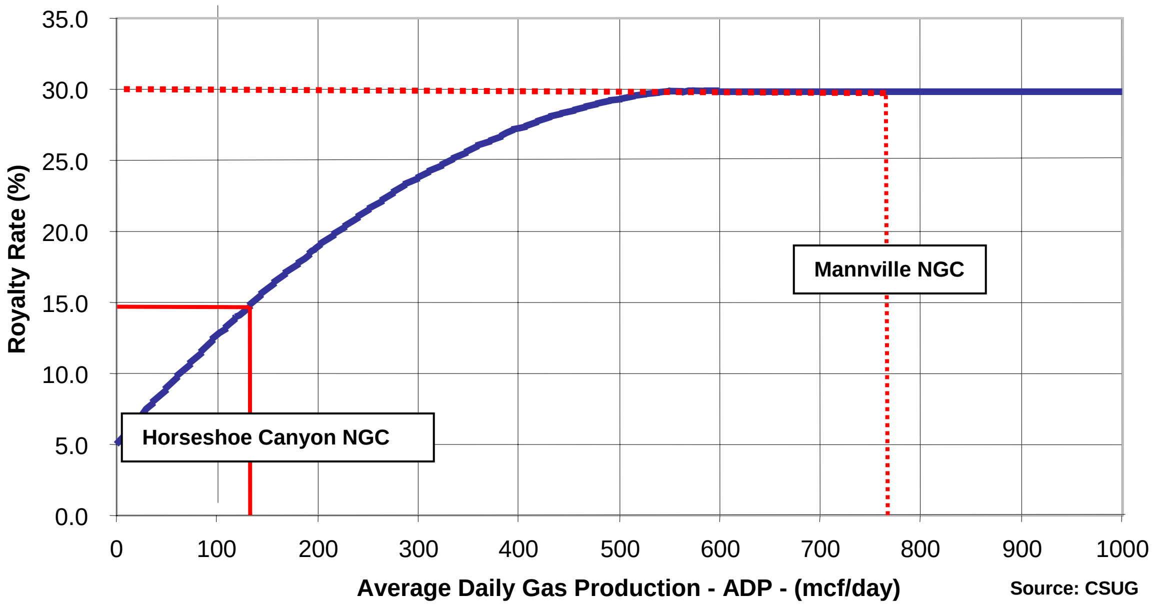


Figure 9.1: Royalty versus Gas Production Rate for Current Alberta Gas Production

"It is important to recognize that In Alberta, the production of NGC is regulated by existing gas production regulations and royalty structure and have not been, nor are there currently, any unique fiscal or tax incentives provided for the development of this resource."

Horseshoe Canyon NGC resources remain competitive at gas prices above $6.00/mcf driven primarily through the application of economy of scale economics that provide some relief for the higher capital cost of development. In contrast, in the technically more challenging resource play of the Mannville coals and potentially in the exploration and development of the Scollard/Ardley coals, technology and economy of scale economics have yet to play a significant impact on capital cost. With these horizontal wells being excluded from the low productivity royalty curve, the ongoing development of these resources is put in jeopardy particularly in times of marginal commodity price and continued high service sector costs.

As Alberta becomes more reliant on unconventional gas sources such as tight gas sands and carbonates and shale gas, companies that may be applying similar technology (multi-lateral horizontal drilling) will face similar challenges for a fair royalty structure that takes into account low productivity individual legs, relative to high capital costs for development and stimulation.

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In United States, the evolution of a healthy vibrant unconventional gas industry was triggered by the implementation of a federal government funded tax credit program (Section 29 Tax Credit). In response to specific requests from the Royalty Review Panel, a summary of this program and its impact are presented in the following section.

9.1 Section 29 Tax Credit

In the United States, unconventional gas now accounts for about 40% of gas production, with about 13 Bcf/D (26%) from tight sands, 5 Bcf/D (10%) from coalbed methane, and 2 Bcf/D (4%) from shales. In 1970, production from these sources was practically nil. The catalysts for this impressive growth were government pricing and tax incentives and a large public and private investment in research for unconventional gas technology. Starting in the 1970's, the U.S. government reacted to the perception of future energy shortages to encourage development of domestic oil and gas with incentive pricing and tax credits. The Natural Gas Policy Act (NGPA) of 1978 provided for classification of gas wells into "special" categories that qualified for incentive prices under NGPA Section 107 for “high cost” gas sources like methane from coal seams, Devonian shales, and other sources as determined by state regulators, such as “tight” gas (see table 9.1). At the time, the incentive pricing was set at twice the rate for “new” gas. The number of Section 107 tight gas well determinations went from 819 in 1980 to 7,639 in 1982[1].

In 1980, as part of the Crude Oil Windfall Profit Tax Act (WPT), Congress provided for tax credits for production of specified alternative fuels. Under the Nonconventional Fuels Production Credit, fuels which qualified for this credit included oil from shale or tar sands, gas from geo-pressured brines, gas from coal seams, Devonian shales, tight sands, and synthetic fuel from coals. This credit was implemented under Section 29 of the Internal Revenue Code. As gas prices became deregulated and the previously enacted NGPA incentive prices became essentially valueless, the IRS used practically the same determination process used to “qualify” wells and reservoirs for Section 107 pricing to establish eligibility for the new section 29 tax credits, as they came to be commonly referred as “The Section 29 tax credit” was originally “equivalenced” to a value of $3.00 per barrel on a BTU-equivalent basis for qualified production and was adjusted for inflation. The credits varied slightly for different fuels. Shale gas and coal bed methane received a higher credit than tight gas, for example. Initial credits for unconventional gas were around $0.50/Mcf and they grew to $1.00 to $1.50/Mcf towards the end of the credit eligibility period. This was a credit against taxes owed, not an adjustment to taxable income, which is of lesser value.

Table 9.1 – General Requirements for Designation as a “Tight Gas” Reservoir for U.S. Incentive Pricing and Tax Credit Qualification

Average Depth to Top of Formation (range, ft)	Maximum Allowable Rate (Mcf/day)
0 - 1,000	44
1,000 - 1,500	51
1,500 - 2,000	59
2,000 - 2,500	68
2,500 - 3,000	79
3,000 - 3,500	91
3,500 - 4,000	105
4,000 - 4,500	122
4,500 - 5,000	141
5,000 - 5,500	163
5,500 - 6,000	188
6,000 - 6,500	217
6,500 - 7,000	251
7,000 - 7,500	290
7,500 - 8,000	336
8,000 - 8,500	388
8,500 - 9,000	449
9,000 - 9,500	519
9,500 -10,000	600
10,000 – 10,500	693
10,500 – 11,000	802
11,000 – 11,500	927
11,500 – 12,000	1,071
12,000 – 12,500	1,238
12,500 – 13,000	1,432
13,000 – 13,500	1,655
13,500 – 14,000	1,913
14,000 – 14,500	2,212
14,500 – 15,000	2,557

Source: Crude Oil Windfall Profit Tax Act (WPT) – Section 29

A) Average in situ permeability in the pay zone must be less than or equal to 0.1 md or otherwise exhibits low permeability characteristics as evidenced by economic data showing the extraordinary costs of stimulation work used and net (rate and economic) results there from, or

B) Stabilized production rate, without stimulation, against atmospheric pressure, of wells completed for production in the (candidate) formation must not be in excess of the rates set out in the table below.

The Section 29 tax credits were only available for wells drilled during a specified time period, and there was also a time limit after which these credits could no longer be claimed. The credits were originally available only for wells that were spudded after December 31, 1979 and before January 1, 1991, and the gas from qualified wells had to be produced before January 1, 2001. This was later modified to extend the spud deadline to January 1, 1993 and the producing deadline to January 1, 2003. Subsequent attempts to extend either the eligibility or production period were unsuccessful.

In conjunction with these pricing and tax incentives, the U.S. Department of Energy had a robust research budget for unconventional gas technology during the late 1970's and 1980's, with a special emphasis on Devonian shales and drilling technology. In addition, the Gas Research Institute (GRI) has research programs for tight sands, shales, and coalbed methane that led to the development of fundamental advances in unconventional gas reservoir characterization and modeling, hydraulic fracturing technology, modeling, and mapping. The GRI funding came from a varying $/Mcf toll on gas transported in interstate pipelines.

Collectively, it can be claimed that this combination of fiscal incentives and R&D investment essentially created the coalbed methane industry and catalyzed the expansion of gas shales beyond the Appalachian Basin Devonian shales. In addition, most of the modern hydraulic fracturing technology being applied today had their roots in these R&D programs. Given Alberta's and Canada's vast unconventional gas resource base, similar programs to develop essential technologies and encourage investment in this sector should accelerate the growth of unconventional gas production to help offset declining gas production. Today, unconventional gas production is slowly growing in Canada, somewhere between 2 and 5 Bcf/D (12 to 29%), depending on the definitions used for unconventional gas. CSUG believes that unconventional gas can reasonably be expected to match or exceed the potential realized in the U.S., with 40% or more of Canada's future gas production coming from unconventional sources.

To achieve this unconventional gas potential in the next decade, new technology must be developed and applied to these unique Canadian resources. Massive investments will be required in exploration, evaluation, and development drilling as well as infrastructure and environmental technologies to ensure these resources are developed responsibly and economically. Fiscal tools and R&D investment could significantly aid this effort.

10.0 Industry Challenges

Development of Alberta's unconventional gas resources continues to grow in response to the decline in production of conventional gas resources and the reliance of industry on this production to fill the gap between supply and demand. As industry moves forward with the exploration and production of this resource, it is faced with significant challenges. In the previous sections of this submission, the size of the resource, cost to develop, risk and sustainability and economics of NGC development were presented and discussed. In this section, the information derived from the previous parts of the submission will be captured in a summary of what challenges the gas industry faces in developing Alberta's NGC gas resources.

10.1 Development of Technology

The success of NGC development within the Horseshoe Canyon Formation has been driven by the development and application of specific technology that allow the NGC to be produced at economic rates. Specific time, energy and perseverance by industry was required to "find the key" to foster commercial success. For the Mannville deep coals and the potential NGC resources of the Scollard/Ardley zone there are still significant technical challenges that need to be overcome before widespread commercial development of these resources occurs. Deep horizontal wells/multi-lateral wells in the Mannville Formation coal beds require specific geosteering technologies to minimize out of zone transigence, post-completion solids migration and control issues and depressurization practices continue to negatively impact stabilized production. There has been limited amount of exploration and production testing of the Scollard/Ardley coals due to the variability of local hydrological conditions and as such industry's understanding of these coals reservoir properties is limited to the point where no clearly preferable drilling and completion technologies have been defined.

The success of the unconventional gas industry in United States was built on a number of government initiatives that provided incentives for research and development. In Canada, while industry has been able to "piggyback" on some of the technologies developed in United States, there is a realization by explorers and producers, that the NGC reservoirs in Alberta have their own unique characteristics and in most cases require a made in Alberta approach to development. The gas industry has been successful for the Horseshoe Canyon Formation in part through the application of shallow gas economy of scale planning but also through the short term increases in commodity price. As gas prices has tended to stabilize at rates near marginal economic threshold, continued R&D for the other NGC reservoirs will be challenged due to the reduction in individual company cash flow and available R&D capital.

10.2 Higher Capital Costs

Within Alberta, unconventional gas resources generally are considered to lie within lower quality reservoirs where:

- Reservoir properties dictate more specialized drilling or completion technologies
- Average well productivity is lower thus requiring modified drilling and completion techniques to optimize wellbore production
- Ultimate recovery of the gas resources is over a much longer period of time
- Higher well density is required to adequately capture the subsurface gas resources

Capital cost for exploration and development tend to be higher on a per well basis. While some economies of scale can be achieved through program multi-well drilling particularly in the Horseshoe Canyon play, compared to conventional gas wells, NGC wells tend have a higher initial capital cost through elements such as:

- Requirement for baseline water well testing
- Higher fracture stimulation costs
- Data collection and pressure/desorption control wells
- Requirement for low pressure gathering systems
- Additional capital requirements for compression

All of the additional capital requirements translate into a longer time frame for well payout and return on capital.

10.3 Price Sensitivity

Analyses completed by CERI on behalf of the Canadian Society for Unconventional Gas illustrates that under the existing taxation and royalty structure, NGC wells completed in the shallow “dry” Horseshoe Canyon play are marginally economic in today’s current gas market. While 1 well per section creates a lower threshold for economic recovery of $3.70 mcf, only about 11% of the resource is recovered. Increasing the well density to 8 wells per section increases the overall resource recovery to 45% but requires a base threshold price of $6.00/mcf for projects to be economically viable. At this higher commodity price there is a modest return on capital, but little room for price volatility. Should market conditions for the price of natural gas decline to less than $6.00/mcf, many of the Horseshoe Canyon gas fields will in effect show a negative return on capital.

For the Mannville Formation, wells tend to have a longer payout time period and economies of scale and project planning are more difficult. The effects of price volatility are even more dramatic when there is a delay in achieving economic production due the requirement for extensive pilot well testing and the additional operational costs associated with de-watering of the reservoir prior to significant gas production. When capital investment and operation costs are built into the equation, Mannville Formation projects, will require a sustainable price threshold greater than $6.00/mcf to be economic.

10.4 Risk and Sustainability

Prior to 2001, there had been no commercial success for NGC in Alberta. While development of this resource has grown at a brisk rate in the last 6 years, there is still a high degree of uncertainty relating to risk and sustainability due to the immaturity of the play. Recoverable reserves over time translate into a barometer of economic viability for each project. In any NGC development, overall project economics need to be evaluated rather than individual well performance. Production profiles and decline curves generally have a less than 5 year production history upon which ultimate recoverable reserves are based. At this stage of development in the province, the long term recoverable gas volume from some NGC developments is not known. Unlike the conventional gas industry which has a long production history, production analog and history matching are not fully applicable for ultimate recovery projections. The infancy of the NGC industry presents a higher level of risk for development and ultimately investment, particularly in fields where technologies are still being developed.

10.5 Current Royalty Structure

The primary drivers in Alberta that have led to the birth and growth of a viable NGC industry has been commodity price and the recognition by industry of the significance of unconventional gas to ensure sustainability from the Western Canada Sedimentary Basin. While NGC developments in the Horseshoe Canyon Formation were able to capitalize on higher commodity prices and the transferability of conventional shallow gas technology to enable development, this was completed under a royalty structure where there were no incentives provided for R&D nor development. The sliding royalty scale for low productivity wells does provide some relief, but with higher capital costs and lower production, Horseshoe Canyon wells are still marginally economic under current gas prices. There are still a large number of wells to be drilled within the Horseshoe NGC "play" and ultimately the overall development is expected to encompass over 40,000 wells from its current total of ~9,000 wells. Technology appears to have turned the development of this NGC resource into one that while still unconventional, could be considered more routine.

In contrast, the deep Mannville wells that, because of high capital cost and ongoing high operation costs, require higher production volumes to be economic, will not likely benefit from the current low productivity royalty scale. The Mannville Formation is thought to contain as much as 60% of the provinces NGC potential and has the potential to be a significant gas supply in the next 10 to 20 years. Under the current royalty structure development of this resource appears to be hindered, particularly when additional cost pressures from low commodity prices are added into the equation. An additional challenge associated with Mannville NGC development is the high variability of the resource which hence requires additional R&D investment to determine optimal drilling and completion technologies in different areas. If development has slowed due to cost pressures and royalty challenges, the development of these technologies will be delayed which would ultimately delay the development of this resource.

The development of Alberta's deep tight gas and gas shales faces similar challenges as the deep Mannville type NGC play. In order to optimize wellbore performance, horizontal drilling either with single legs or multi-lateral configuration appears to be the preferred drilling and completion method. Individual leg production of gas is usually low relative to the capital costs required to develop the field. Collectively a commingled gas stream, will be forced to pay a higher royalty rate even though individual well leg performance is low. This aspect of the current royalty structure needs to be reviewed in light of drilling trends in the industry.

11.0 Conclusions

The rapid growth of the NGC industry in Alberta since 2001 has been triggered primarily as a response by the natural gas industry to replace declining production from conventional gas resources. As conventional gas production continues to decline from Western Canada, industry will become more dependent on unconventional gas sources such as tight gas and natural gas from coal to "fill the gap" between supply and demand. The gas industry faces a number of challenges if the development of the vast NGC resources in the province is going to continue and meet this increased demand. These challenges:

Development of Technology
High Capital Cost
Commodity Price Sensitivity
Risk and Sustainability of Production
Current Royalty Structure

have created a difficult business climate in which companies wishing to develop the provinces NGC resources must operate. Clearly at the present commodity price structure and cost for services, new NGC developments are at best marginally economic. Industry has responded to this environment by drastically reducing capital spending for NGC. Current estimates are that exploration and development activity has slowed by as much as 44% from 2006.

Economic analysis of lower risk NGC developments in the Horseshoe Canyon play indicate that a commodity price threshold of $6.00/mcf is required for a modest return on investment under the current provincial royalty and tax structure. NGC projects that are more capital intensive or with a higher risk profile would require an even higher base price threshold to be economic.

In order for industry to continue to develop the NGC resources of the province and to invest in technologies that will allow these resources to be economically competitive in the North American gas market, the royalty structure for gas production from Alberta must recognize the fundamental differences between NGC resource “plays” and conventional gas developments. Any changes to the existing royalty structure must take into account the industry challenges and provide a fair share to Albertans yet still provide a strong fiscal climate that will enable the resources to continue to be developed. In some cases, consideration should be made to provide incentives for the development of technology that will assist in the exploration and production of the more challenging NGC resource plays in Alberta.

The Canadian Society for Unconventional Gas supports a fair natural gas royalty structure that provides long term sustainable revenue to Albertans while at the same time encouraging industry to continue to invest in the exploration and development of the province’s unconventional gas resources in an environmentally and socially responsible manner.

Glossary

Coalbed Methane – Coalbed methane (CBM) is the natural gas found in most coal seams. CBM is almost pure methane, the principal component of natural gas. CBM is cleaner than conventional natural gas and can be sent to market with minimal processing, making it a cost-effective and clean-burning fuel.

- In the United States, the gas is generally referred to as coalbed methane (CBM) or coal mine methane (CMM)
- Alberta uses NGC (Natural Gas from Coal) since natural gas rules apply, and CBM
- British Columbia calls it coalbed gas (CBG)
- In Australia, coal seam methane (CSM) is often used

Whatever the name, it is the same thing, **natural gas that is produced from coals**.

Adsorption – Refers to the molecular bonding of a gas to the surface of a solid. In the case of NGC, methane is absorbed or bonded to the coal.

Casing – Steel pipe placed in a well and cemented in place to prevent the geological formations from collapsing, and to isolate water, gas and oil from the other formations.

Cleats – The network of natural fractures that form in coal seams as part of the natural maturation process of coal.

Coalification – The natural process that converts organic matter into coal over time.

Coal seam – A layer of coal found in the subsurface.

Completion – The activities and methods to prepare a well for production. Includes the installation of equipment for production from a gas well.

Conventional natural gas – Conventional natural gas is made up of 80–90 per cent methane, and consists of a mixture of hydrocarbon compounds and small quantities of various non-hydrocarbons.

Desorption / desorbed – To remove (an adsorbed or absorbed substance) from.

De-watering – The process of removing water from a coal seam. A pump located at the wellhead removes the water that naturally occupies the fracture reducing the reservoir pressure drawing the gas out of the coal. De-watering is required to reduce pressure within the coal seam, which in turn allows the methane gas to be released from the coal.

Directional Drilling – A well drilled at an angle from the vertical. Directional drilling can be used when geographical issues such as a river bank or other body of water prevent vertical drilling. Under normal conditions vertical drilling is used.

Disposal Well – Where produced water from NGC wells is injected into an underground formation for disposal.

Downstream – The refining and marketing sector of the petroleum industry is commonly referred to as the downstream sector.

Enhanced Recovery – The use of artificial means to increase the amount of hydrocarbons that can be recovered from a reservoir. A reservoir depleted by normal extraction practices can usually be restored to production by secondary or tertiary methods of enhance recovery.

Fault – A fracture surface in rocks along which movement of rock on one side has occurred relative to rock on the other side.

Flaring – The burning of natural gas as a means of disposal. Flaring is restricted to short-term testing, well workovers or rare emergency situations.

Formation (geologic) – A rock body distinguishable from other rock bodies and useful for mapping or description. Formations may be combined into groups or subdivided into members.

Fracture Stimulation – Forcing fluid at high pressure into an existing fracture in the coal seam to cause it to widen, creating passages for the gas to escape and improving well productivity. Advanced fracturing techniques make it easier to find and recover natural gas, as well as extend the longevity of older wells.

Hydrostatic Pressure – The force exerted from water.

Lithification – The process of converting sediment to rock.

Methane – The principal ingredient in natural gas. Conventional natural gas is made up of 80 – 90 per cent methane. NGC, an unconventional natural gas, is made up of more than 95 per cent methane.

Midstream – The processing, storage and transportation sector of the petroleum industry.

Permeability – The rate of flow of a liquid or gas through a porous material.

Sour Gas – Natural gas that contains hydrogen sulphide (H_2S).

Subsidence – Land subsidence is the lowering of the land-surface elevation from changes that take place underground. This occurs when large amounts of ground water have been withdrawn from certain types of rock. When the water is withdrawn, the rock falls in on itself.

Sweet Gas – Natural gas containing little or no hydrogen sulphide. NGC is considered a sweet gas.

Thermogenic – General or production of heat, especially by physiological processes.

Unconventional gas – Unconventional gas is defined as gas resources that lie in lower quality reservoirs and that require some unique application of drilling or completion technology to allow economic production of the resource. Unconventional sources are generally categorized as tight sands and carbonates, shale gas, coalbed methane (or NGC) and gas hydrates. As development continues unconventional gas development is becoming more routine. Typically, CBM consists of more than 95 per cent methane.

Water Quality – De-watering a coal seam can produce water of varying volume and quality from usable to saline. Testing of the produced water determines the disposal method. CBM produced water is generally of good quality. Water that meets quality standards may be allowed to flow into surface drainage or into ponds and seep back into the soil or evaporate naturally after receiving various government approvals. Water that does not meet quality standards because it tests too high in total dissolved solids (including salts) is injected into suitable underground formations after receiving government approvals.

Wellbore – A hole drilled into the earth, usually cased with metal pipe, for the production of gas or oil.

13.0 Sources of Information

Alberta Department of Energy
Alberta Energy and Utilities Board
Alberta Geological Survey
Canadian Association of Petroleum Producers (CAPP)
Canadian Energy Research Institute
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MHeath & Associates
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