Paper #1-2

DATA AND STUDIES EVALUATION

Prepared by the Data & Studies Subgroup
of the
Resource & Supply Task Group

On September 15, 2011, The National Petroleum Council (NPC) in approving its report, *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*, also approved the making available of certain materials used in the study process, including detailed, specific subject matter papers prepared or used by the study's Task Groups and/or Subgroups. These Topic and White Papers were working documents that were part of the analyses that led to development of the summary results presented in the report's Executive Summary and Chapters.

These Topic and White Papers represent the views and conclusions of the authors. The National Petroleum Council has not endorsed or approved the statements and conclusions contained in these documents, but approved the publication of these materials as part of the study process.

The NPC believes that these papers will be of interest to the readers of the report and will help them better understand the results. These materials are being made available in the interest of transparency.

The attached paper is one of 57 such working documents used in the study analyses. Also included is a roster of the Subgroup that developed or submitted this paper. Appendix C of the final NPC report provides a complete list of the 57 Topic and White Papers and an abstract for each. The full papers can be viewed and downloaded from the report section of the NPC website (www.npc.org).

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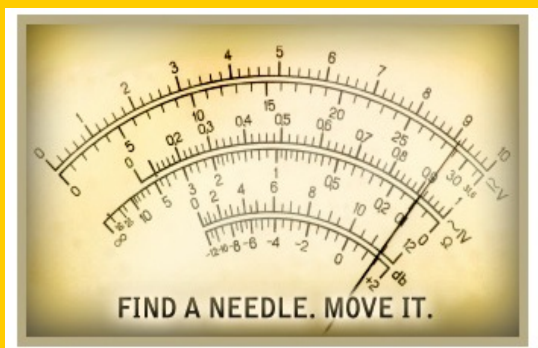
WHATS NEEDED TO MAKE A DIFFERENCE AND…



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Note: the majority of industry, government and public data were collected in 2010 and this topic paper was developed in the first quarter of 2011. We have attempted to incorporate recent, public, energy data releases and publications in preparing this final topic paper document.

Supply Data & Studies Evaluation
Team leader: Charlie Sheppard & Kevin Regan
Date submitted: August 19, 2011

I. Executive Summary

Energy; whether its hydrocarbons, nuclear, solar, wind, hydro, geothermal; is important in everybody's lives, since it impacts so many different tasks and systems we encounter everyday. There has been a continued focus and urgency about the role of energy in long-term economic vitality and prosperity, environmental impacts, and potential concerns about national energy security. Over the past fifteen years, the National Petroleum Council (NPC) has been asked to study and make recommendations on (1) whether, and (2) how affordable, energy supplies can be delivered to satisfy growing energy demand. These past studies include: Future Issues – A View of US Oil & Natural Gas to 2020 (1995); Meeting the Challenges of the Nation's Growing Natural Gas Demand (1999); Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy (2003); Facing the Hard Truths about Energy – A comprehensive view to 2030 of global oil and natural gas (2007); plus a separate Future Transportation Fuels study that is being worked simultaneously with this effort – The Prudent Development of North American Oil and Gas Resources.

In US Energy Secretary Chu's request letter to the NPC for this study, he emphasized the importance of the administration, congress and government agencies having the most up-to-date understanding of key energy data, information and knowledge for considering policy options that can enhance economic growth, environmental protection and national security. He specifically asked the NPC study participants to reassess the North American resource production supply chain and infrastructure potential, and the contribution natural gas can make in a transition to a lower carbon fuel mix. Your study should describe the operating practices and technologies that will be used to minimize environmental impacts and also describe the role of technology in expanding accessible resources. The United States has the capability, enthusiasm and human resources to develop a future vision and line of sight for our national energy policy and strategic direction. The challenge is to generate solutions that will be right for our country, North America and also the global market place. The NPC participants have the opportunity to be a microcosm of the nation and serve as a stimulant for creating alignment with diverse stakeholders around an energy policy in the national interest.

The data/studies team's objective was to evaluate if the North American oil and gas remaining resources and production capacity could keep pace with the highest, future demand scenarios. While international oil and gas imports can and will play a role in meeting North American energy needs, our goal was to assess the size of the North American resource base, the potential supply capacity of that resource base and finally the challenges and issues of that production growth.

There are a range of views regarding the future energy mix that will be required to satisfy the United States, North America and the world's energy needs to the year 2050. The primary demand driver is population growth and migration, GDP growth, and manufacturing output. The energy outlooks evaluated for both the current NPC North America and the 2006-07 Global Oil and Gas studies forecasted a wide range in the United States liquid (20 - 30 million barrels a day) and natural gas demand (20 - 40+ TCF per year) by 2030.The resultant carbon emissions are a function of the magnitude of energy demand and the supply fuel mix. Global CO2 emissions could grow from the around 30 billion metric tons in the last decade to in excess of 50 billion metric tons in the most optimistic energy consumption scenarios by 2030.

While not the primary objective of our investigation, environmental impacts and demand scenarios are directly tied to industry activity and investment levels required to grow North America's productive supply capacity. Thus, a fully integrated, comprehensive analysis and understanding of the impacts throughout the entire, complex energy chain is needed to provide balanced policy recommendations. As articulated in the NPC Hard Truths Global Energy Study, a tenant of any energy policy should be to reduce energy demand by increasing energy efficiency as much as possible, since every BTU that is not needed, reduces supply needs while reducing emissions and other environmental impacts. Another pillar of an energy policy is to promote supply diversity and production capacity growth which diversifies energy security, helping to sustain a balance between supply and demand and having a substantial impact on energy prices and volatility.

The North America oil resource and supply picture is relatively straight forward. Canada and Mexico are currently exporting oil into the US markets and the only question is whether their resource base and supply capacity can continue to be meet their internal demand, while maintaining export volumes. The United States resource base, plus imports from Canada and Mexican, has not been sufficient to meet the 20+ million barrels a day of liquids that is being consumed today. Therefore, we have focused on estimating if the combined North American resource base and future production capacity could satisfy internal demand levels, or how large the supply gap would be in the future. Our results suggest that North American production capacity can not grow fast or large enough to meet the growing needs in the United States for liquids unless there is a significant reduction in liquid demand. This might occur if there is substitution of liquids with other energy sources in the transportation (lion's share of liquid needs), and less so, the power, industrial and residential/commercial sectors.

The North America gas resource and productive capacity picture are considerably more complex. The industry's relatively recent application of horizontal drilling and hydraulic fracturing practices has led to a greater understanding of the potential magnitude of the US and Canadian recoverable resource base which is now believed to have grown considerably (2+ times?). Previously, there was a perception that domestic supplies could not meet internal demand requirements and significant volumes of LNG imports would be required. Thus, our goal was to determine if there are sufficient, affordable domestic gas resources that can be developed to meet all potential demand scenarios. The range of demand outlooks for the gas of 20 – 40+ TCF a year reflect:

- Low Side cases – low economic growth and/or curtailing energy use to minimize carbon emission and other environmental impacts
- "Mid" cases that reflect a historical share (%) in the overall fuel mix coupled with moderate economic growth consistent with historical trends
- High Side cases that consider increased natural gas penetration in the power and even transportation sector, replacing coal and oil. This also would likely improve the resultant environmental impact for these demand growth scenarios and would close the liquid import gap which has both economic and energy security advantages for the United States.

The North American energy business environment has regressed over the last several years. This is largely a function of the economic recession and a few, large industry operational failures (e.g. Macondo blowout and GOM oil spill disaster; San Bruno California pipeline explosion; Alaska TAPS pipeline leak; etc) that has increased concerns about industry operational practices and safety performance. There has been increased concern and media coverage regarding water usage and management for the shale and tight gas production capacity expansion that is anticipated in the future. Hopefully, by identifying best practices and new solutions that minimize the chance and impact of future occurrences, the excellent performance of industry over the last 25+ years will be recognized. Government and industry groups are discussing the merits of new regulatory initiatives including access to new acreage and business opportunities; well and project planning/permitting requirements; industry best practices and responsiveness capabilities to major operational problems such as spills, pipeline leaks, etc; greenhouse gas emission and other environmental requirements; and the transportation and sequestration of carbon dioxide (CO2).

We believe the range of supply outlooks can be characterized by three scenarios. The constrained supply cases correspond to a highly regulated industry environment, with curtailed access/development of new opportunities, together with a weak economy. Mid case scenarios reflect various iterations of industry, public and government business-as-usual cases, where economic growth and product prices will be the industry's primary investment considerations.

Unconstrained or high-side cases will require considerable alignment between industry, government and public stakeholders towards a common, shared, long-term vision for the future direction of the energy sector. The oil cases require significant long term commitments to diversifying the portfolio of North America supply areas; early and increased data collection to understand the new play areas (some currently in moratoria areas); research and technology to assess the commercial viability and development of large Rockies unconventional oil resources; and a new long distance pipeline to carry Canadian oil sands to US Gulf Coast refineries. The low and mid gas supply cases are likely to be similar conditions to the oil scenarios described above. However, the high gas production scenarios likely include an increasing gas share of the overall energy mix in the United States and Canada (?) and greater gas consumption in the power and transportation sectors. We have assessed the industry requirements and fundamentals to achieve this possible paradigm shift for gas, and while we believe it is feasible from a resource base and industry capability standpoint, considerable alignment and cooperation between industry, government and public stakeholders will be required to increase production rapidly and sustain 30 to more than 40+ TCF per year production level for future decades.

Shale gas is the potential game changer of the North American supply sector. The shale gas resource base and future production levels are likely as large as all the other current commercially viable gas sources combined, and shale gas has redefined the marginal (lowest cost new supplies) cost of new gas likely to enter the market place (including LNG imports). United States tight gas has been contributing in excess of a quarter of the total US domestic gas production and the resource base is large enough to potentially support production levels around 8 - 10 TCF/YR into the future. There are considerable gas resources in the Arctic, and two (Alaska and Mackenzie) large gas projects could contribute in excess of 3 – 5+ TCF/YR into the Canadian and US markets. These are large fields (>5 TCF fields with high flow rates), however they require significant capital commitments given the large transportation infrastructure requirements. Arctic supplies will be needed in the future, but Arctic project timing is likely dependant on the marginal cost of natural gas with the North American market, competing with other US/Canadian domestic supplies and LNG imports. While gas hydrates might be a future contributor to North America supplies; considerable research, technology enhancements; experimentation and pilot projects are required to assess the commercial viability of these resource (10’s to 1000’s of TCF).

Figure 1: Source – Industry Aggregated Database

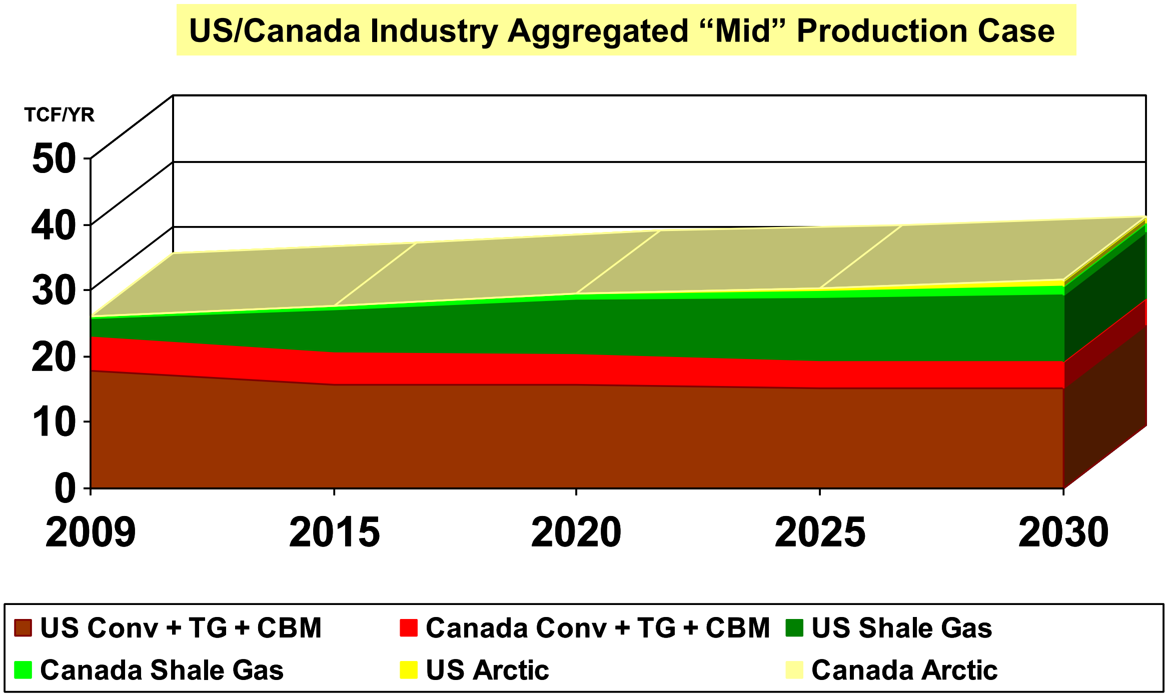


Figure 2: Source – Industry Aggregated Database

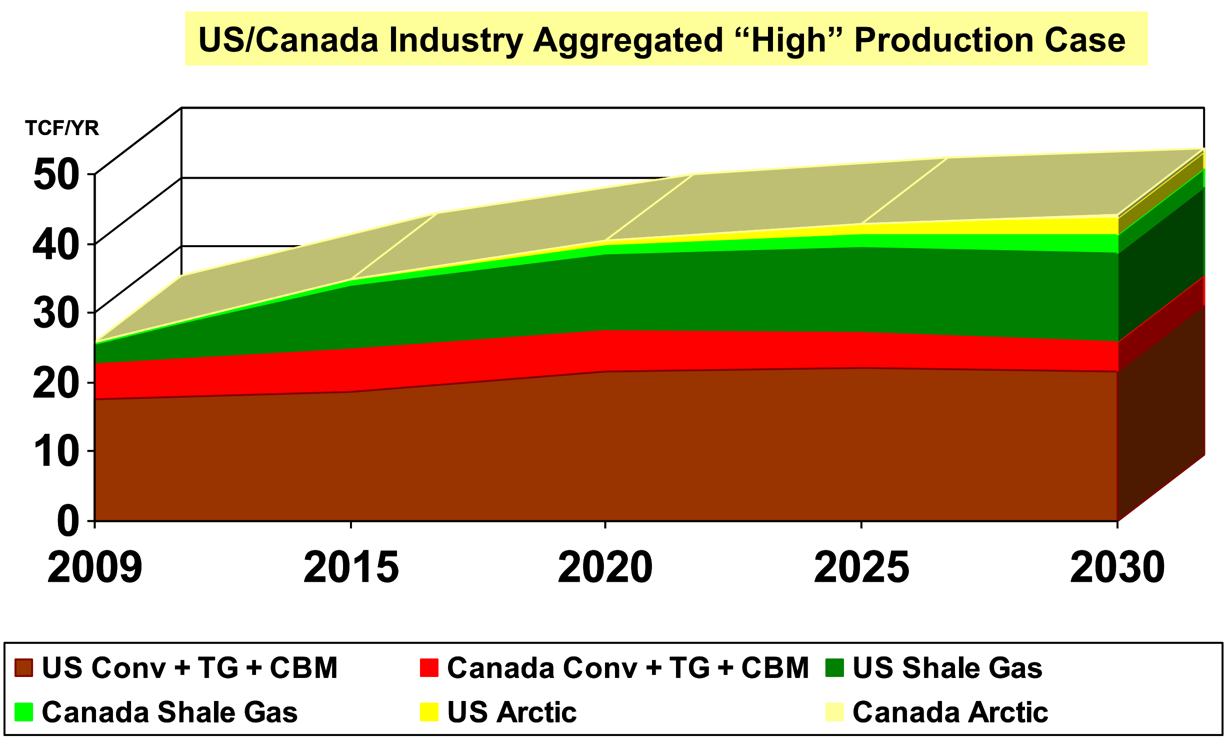


Figure 3: Source – Industry Aggregated Database

NA Oil and Gas Resources/Supplies That Can Move the Needle		
Gas and Oil Sector Priorities *(In descending order)*	**Size of the Prize**	**Key Enablers**
Shale Gas	Recoverable Resource Potential = US (700 -1800 TCF) & Canada (200-600 TCF); future NA production levels possibly in excess of 20+ TCF/YR	Hydraulic Fracturing; Resource Intensive – people, equipment, materials
US Tight Gas	Recoverable Resource Potential = 200 - 550 TCF; future NA production levels possibly in excess of 8+ TCF/YR	Hydraulic Fracturing; Resource Intensive – people, equipment, materials
Arctic Gas	Recoverable Resource Potential = US (150 – 350 TCF) & Canada (50 – 125); future NA production levels possibly in excess of 4+ TCF/YR	Long Distance Pipeline and Infrastructure Project Commitment and Construction
Canadian Oil Sands	Recoverable Resource Potential = 150 – 310 BBL; future production levels possibly in excess of 5+ MMBD	Long Distance Pipeline and Infrastructure Project Commitment and Construction
US GOM Oil	Recoverable Resource Potential = 40 – 60 BBL; future near and mid term production levels of 1.5 – 3.0 MMBD	Resumption of pre Macondo Deepwater Drilling Activity Levels; Paleogene reservoir performance and commerciality
US and Canada Tight "Shale" Liquid Plays	Recoverable Resource Potential = 10-20 BBL; future NA production levels possibly in excess of 1+ MBD	Hydraulic Fracturing; Resource Intensive – people, equipment, materials; How much is crude/condensate (refined transportation products) vs NGL's
New US L48 Offshore & US and Canadian Arctic Areas	Recoverable Resource Potential = 80-100 BBL; mid term (e.g. US West Coast) and longer term (e.g Arctic) production levels in excess of several MBD	Opening of Moratoria Areas and Data Collection; Timely Exploration / Development Program Approvals
Long Term: US Rockies Shale "Kerogen"	In Place 1+ Trillion Barrels, Recoverable Resource Potential & Commercial Viability ??	Continued technology evolution and experimentation to prove commercial viability; Resolution of any outstanding environmental impact concerns

The largest remaining North American oil resource potential is the unconventional Canadian oil sands (150 – 300+ billion barrels of recoverable resources) and US Rockies Shale kerogen (? recoverable resources, but over 1 trillion barrels in place) plays. The US unconventional Rockies oil plays, while having significant in place volumes, need considerable research, experimentation, technology advancements, and the resolution of above ground challenges. These issues all the need to be addressed to assess the commercial viability before proceeding with large scale production projects that could materially impact the oil supply situation. This is not expected until after 2030.

Canadian oil sands are already contributing around 1.5 MBD and could grow to 5 MBD out beyond 2030, which could represent approximately 40-50% of all US and Canadian crude production. Infrastructure expansion to transport this heavy crude to suitable upgrading facilities and refineries will be necessary to achieve these large growth aspirations. The Gulf of Mexico (GOM) is a world class petroleum system with still about 50 billion barrels of remaining potential. A considerable amount of the remaining resource potential is located in the lower permeability, Paleogene play (commercial viability/attractiveness still uncertain) and a number of new play types which in total have less overall potential than the current Miocene deepwater play. The Miocene play producing fields are the largest contributors to the current 1.5 MBD production level in the GOM. Future supply outlooks from the GOM ranged from 1 – 3 MBD and largely reflect the uncertainty regarding industry activity levels and acreage availability in future lease sales that has arisen since the tragic Macondo blowout and large oil spill. While there is significant near to mid term (e.g. world class petroleum system – offshore California) potential in other lower 48 offshore areas and the US and Canadian Arctic (80 – 100 billion barrels total for all these areas); new regulatory and permitting requirements plus acreage access will drive activity levels in these areas.

Finally, the liquid rich areas in the shale gas plays, Bakken/Three Forks and Monterey tight oil reservoirs have been actively pursued by industry over the last five years. Production has grown in excess of 300,000 barrels a day from these plays (based on data collected by yearend 2010). The current resource assessment of the tight oil plays is relatively small (10 – 20 billion barrels) and thus we don't anticipate the production levels are not expected to grow much beyond 1+ MBD in the future unless there is a step change in well performance or expansion of the resource base. Additionally, it's still unclear how much crude and condensate vs. natural gas liquids will ultimately be recovered from the shale gas plays, which has major price realization and processing implications. The individual, crude and condensate production rates for new wells are relatively low after the steep initial decline in the first year of production; however they are profitable and contributing to growth in the L48 onshore sector. We anticipate that as the US onshore conventional oil field production levels continue to decline, the increased "tight oil" activity may partially offset this decline in the next 10 to 20 years.

The only other area that could contribute material volumes to offset natural field declines in the mature US L48 onshore which is producing around 3 million barrels a day is from enhanced oil recovery resulting from injecting carbon dioxide (CO2) into the reservoir. The industry has been successful in recovering additional oil from older fields applying this technology and utilizing natural sources of CO2. There is considerable debate as to how much additional oil can be recovered from the fields that haven't been flooded with C02 as some of these are not suitable, while others are currently not "connected" to a natural source of CO2, requiring infrastructure development in these fields. While anthropogenic (man-made CO2) capture, transportation, injection and storage for enhanced oil recovery is another potential source of CO2, there is significant uncertainty regarding the cost of supply, regulatory requirements, and construction of new onshore pipelines necessary for commercial project viability.

Figure 4: Source - Industry Aggregated Database

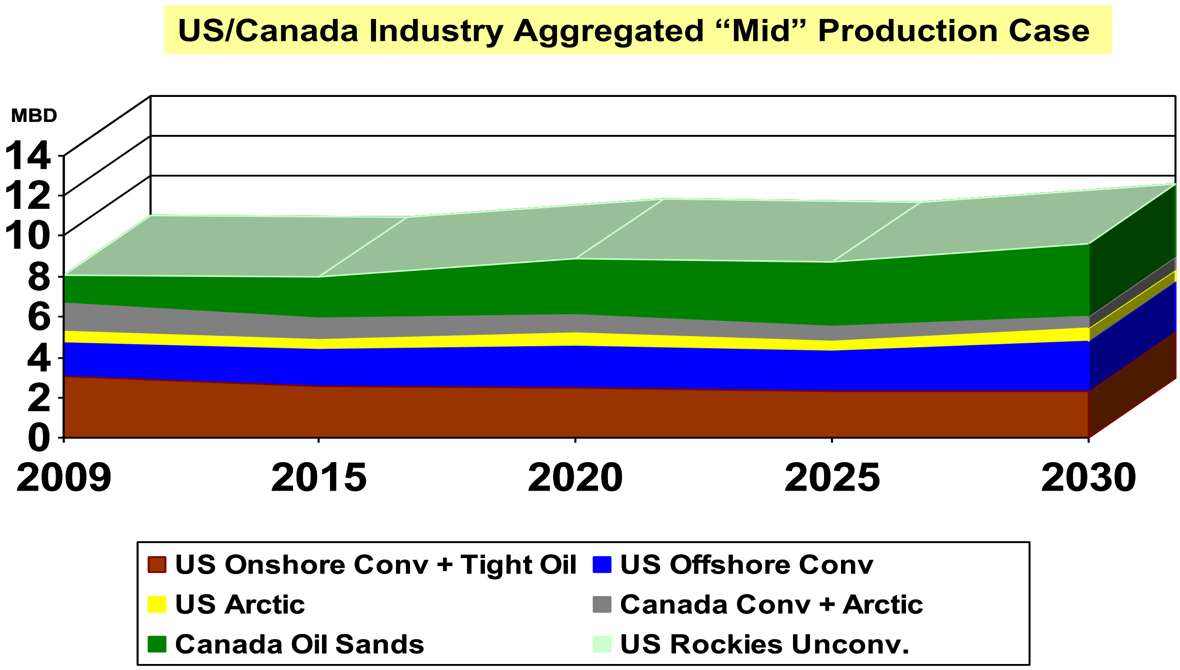
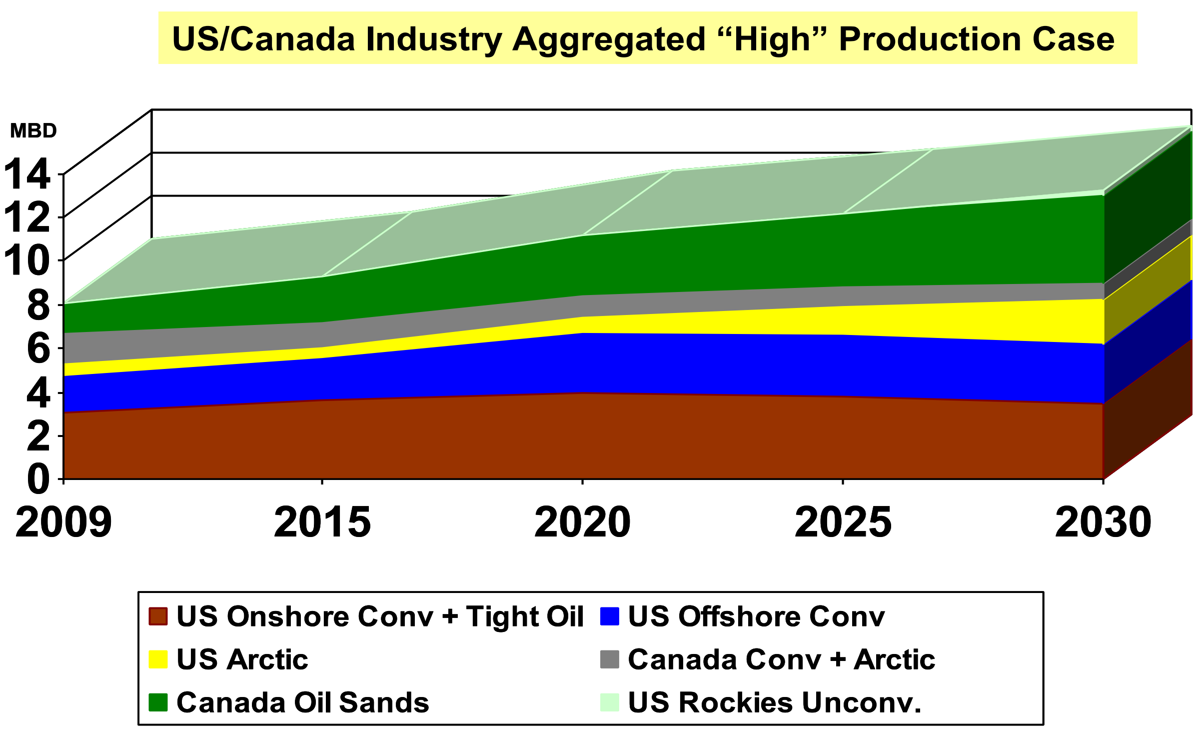


Figure 5: Source – Industry Aggregated Database



While the oil and gas resource base is large enough to support the aggregated, industry estimate of future supply contributions for various US and Canadian oil and gas segments in Figures 1-5, it is the development activity converting resource into production that may cause concerns, including:

- Water use and management
- Uncertainty of new greenhouse gas regulations and costs
- Acreage and resource access in remote and protected areas
- Industry capacity given experience loss from aging workforce and increased materials and equipment requirement in high "oil and gas" manufacturing style plays (e.g. shale/tight gas; Canadian oil sands; and "tight" oil) growth
- Pace of infrastructure de-bottlenecking and new projects
- Government "take" – future revenue sharing (federal, state and local)
- Surface/environmental footprint (e.g. Canadian oil sands; Rockies unconventional oil)
- Exploration and development project planning (e.g. offshore spill preparedness, etc.)
- Regulatory requirements and liability considerations for anthropogenic C02 capture, transportation, injection and storage
- Capital availability – attracted to projects/areas with clear rules of the game, contract sanctity; business environment/political stability; etc

Industry, government and the public can all play a role in enabling supply diversity and domestic production capacity growth. Its all a matter of choice. Industry will continue to actively progress and address the challenges above in order to implement new projects and plays. However; from a policy and priorities standpoint; industry, government and the public can accelerate and enable domestic supply capacity by resolving some of the outstanding issues in the most important areas that would curtail significant future volumes: (1) Hydraulic Fracturing; (2) Offshore Drilling and Spill Responsiveness; (3) Resource Access; and (4) Integrity and growth potential of the liquid and gas infrastructure network.

In summary, previous estimates from a variety of industry and government sources indicate a significant resource base exists within North America to provide up to 50% of current and forecast demand for US liquid petroleum requirements and 200% of natural gas. Using natural gas to displace oil and coal as an energy source would increase North American self sufficiency and reduce reliance on foreign supply. Achieving this level of North American production would require an aggressive development plan and agreement between industry, regulators, policy makers and the public as to the appropriate balance between supply development, environmental protection and economic growth. The optimum energy vision and strategic direction for the United States might also be considered and

utilized by others in the international community to address their energy needs/issues.

Ultimately, consumer preferences and future demand requirements will be met by multiple energy sources. In order to address the difficult choices that will have to be made and resulting consequence accepted, we believe that a more comprehensive and quantitative assessment of the merits for each energy source alternative should be completed. The below table is an initial qualitative attempt to generate interest for a transparent, comparative study for all energy source alternatives. This study should include: the size of resource base; supply cost analysis; production capacity, capabilities and challenges; operational and infrastructure requirements; and safety, health and environmental impacts.

Figure 6: Source – Sheppard & Regan Illustration

Ideal Mix?	Supply Cost	Environment Impact	US-Self Sufficiency	Comments
Oil	Moderate	High	-	OPEC is key to growth capacity
Gas	Low	Low - Moderate	+	Abundant resources
Coal	Low–Mid	High	+	Supplies largely in US, China, Russia, India & Australia
Nuclear	Moderate	Moderate - High	+	High Capital Cost & Safety Concerns
Biomass	Moderate	Low - Moderate	-	Impact on Food Prices?
Wind	Mid-High	Low	+	Transmission issues
Solar	High	Low	+	Technology advancement to lower costs
Hydro	Low	Low	-	Limited Supply
Geothermal	Moderate	Low	-	Limited Supply

The supply data studies team believes we "CAN MOVE THE NEEDLE" and it is feasible to reduce oil imports, energy dependence and US GHG emissions while also benefiting the

economy! We can optimize the supply mix by growing US and North America natural gas (in the power and transportation sectors) and oil focus/investment thereby reducing the need for foreign imports, increase investment in the US workforce and infrastructure, and promote investment in research and technology in all viable energy sources.

II. Introduction

Uncertainty surrounding North American energy resources and industry's ability to develop these safely can stifle investment. Since all energy sources can affect economic growth, energy security and the environment differently, as America's energy mix evolves, stakeholders will be faced with inevitable economic, environmental and energy trade-offs. To the extent they are affordable, consumers prefer clean energy supplies, assuming they are reliable and secure. However, renewable and cleaner fossil fuel energy alternatives can be relatively expensive, and not as reliable as proponents advertise. The remaining North American oil and conventional gas resource base is also becoming more costly and challenging to develop, although continued technology investment and advances can help accelerate defining the size of the endowment, locating resources, and producing/transporting these supplies into the market place. Many worry that oil and gas prices will rise again, especially if development, operating and regulatory costs escalate in the future.

Secretary Chu recognized these issues, as well as "game-changing" views regarding North America's unconventional gas resources. He requested the National Petroleum Council (NPC) help provide "the most up-to-date understanding of the North American conventional/unconventional oil and gas resources production supply chain and infrastructure potential to the Congress, Administration and relevant agencies to consider energy policy measures that enhance energy security and economic competitiveness. The contribution that natural gas can make in transition to a lower carbon fuel mix and the operating practices and technologies that will be used to minimize environmental impacts are key elements." In his letter to the NPC on September 16, 2009 he went further and stated that a "policy objective is to protect the Nation from the economic and strategic risks of excessive reliance on foreign oil and the destabilizing effects of a changing climate". North America's leadership in natural gas development could be celebrated as a technological achievement and play a role in resource development in other parts of the world.

The objective of the Data and Study Analysis Team (in the Resources and Supply Task group of the North American Natural Gas and Oil Resources Study) was to understand the:

1. Uncertainty surrounding the size of North America's conventional and unconventional oil and natural gas resource base, and
2. The challenges and enablers to convert this endowment into production/supply volumes that can help meet the future energy needs of North America.

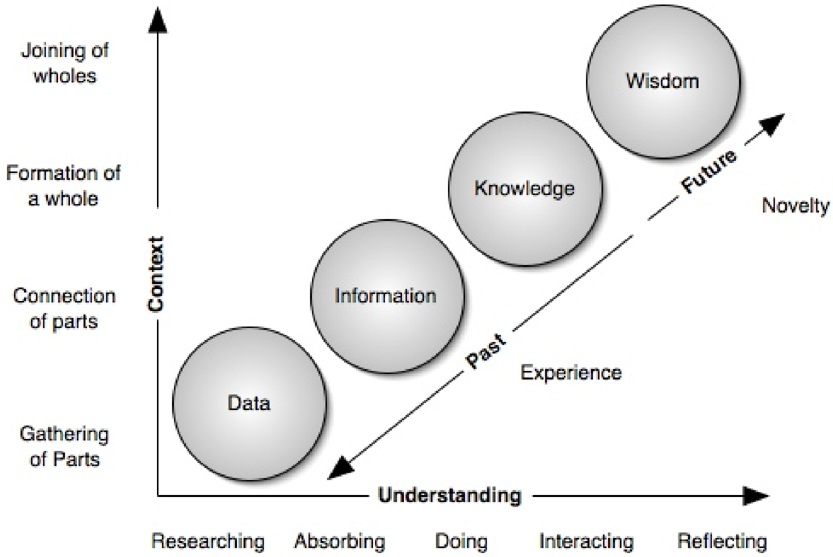
The Data and Study Analysis Team was comprised of diverse skill-sets, experiences, and expertise from participants from large integrated energy companies (e.g. Chevron, ExxonMobil, Shell), the major independent oil and gas producers with representatives of the American Natural Gas Alliance (e.g. Encana, Questar), large industry service companies (e.g. Halliburton), consultant companies (e.g., ICF International, Nehring Associates and Wood Mackenzie) and US and Canadian government agencies.

In conducting a "study of the studies", the Team evaluated a broad, diverse range of energy outlooks. The study scope was limited to North America with focus on the 2010-50 timeframe, and a full value chain (endowment to the burner tip) mindset and approach. While the study was limited to North America, the team benefited from the insights and learning's from many of the same issues addressed by industry and government representatives that also participated in the 2006-07 NPC Hard Truths study (see Appendix 1). While our recommendations and policy input are in response to Secretary Chu's request, these can also be applied by other global policy makers.

The team was dedicated to working through the process flow below to ensure a scientific, fact-based foundation for all the findings and recommendations. The data robustness assessment and interpretation scope of this study plus the lessons learninged for application in future studies is summarized in Appendix 2. A data repository with query capabilities will be publicly available for future use by all stakeholders.

Data → Findings → Integration/Recommendations → Report Writing/Policy Input → Study Participants Alignment and External Report Out/Communication

Figure 7: Source – Sarah Frasier



included both conventional and unconventional resources for various geographic splits (e.g. country, region, basin and play). An assumptions page was also included to help understand the key challenges and potential enablers for the future production capacity.

Data was collected from public, government, industry and consultant sources. Approximately 50 publicly available energy outlooks were examined by the supply team. Three graduate students from Rice assisted in collecting publicly released, energy outlook reports and downloading the available data into templates for comparison with the government and industry data sources. The approaches for these energy outlooks varied considerably, as did their vintage (1990's to 2010). While we evaluated all the data, we found the most recent gas resource and production estimates to be the most relevant, since many of them contemplated the technological breakthroughs for unconventional gas over the last decade.

The United States and Canadian government provided integrated energy outlooks (e.g. the Energy Information Agency (EIA), the National Energy Board of Canada (NEB), the International Energy Agency (IEA), the United States Geologic Society (USGS) and the Bureau of Ocean Energy Management (BOEM). More than 80 energy and consultant companies received a request to complete the comprehensive resource, production and supply chain survey/template. Approximately 25+ industry and consultant templates were returned, and, to maintain the confidentiality of individual company's proprietary data, then aggregated into the 12 unique cases below:

- Low, Median, and High for Large Integrated Energy Companies

- Low, Median, and High for Major North American Oil and Gas Producers
- Low, Median, and High for All Exploration and Production (E&P) Companies
- Low, Median, and High for Consultant Companies/Institutions

The Data and Study Analysis Team coordinated and facilitated several interpretation workshops to discuss all the available data from the public, government and aggregated industry outlooks. Two workshops were held in Houston, a third in Calgary, and a fourth in Washington DC. Representatives from all the various study groups (comprised of industry, academic and government stakeholders) were invited to maximize the perspectives, insights, expertise utilized in the data interpretation and promote discussion of key issues, findings and recommendations. These workshops covered the major North American oil and gas resource/production wedges, including:

- For Oil, Condensate, and NGLs:
    - US Onshore Conventional;
    - US Offshore Conventional;
    - US Arctic;
    - US Unconventional (e.g. Tight Oil, Oil Sands and Shale "Kergoen");
    - Canada Onshore Conventional;
    - Canada Offshore Conventional;
    - Canada Arctic
    - Canadian Oil Sands

- For Natural Gas:
    - US Onshore Conventional;
    - US Offshore Conventional;
    - US Arctic;
    - US Shale Gas,
    - US Tight Gas;
    - US Coal Bed Methane;
    - Canada Onshore Conventional;
    - Canada Offshore Conventional;
    - Canada Arctic
    - Canada Shale Gas;
    - Canada Tight Gas;
    - Canada Coal Bed Methane

All of the above production wedges were evaluated within the context of liquids vs. liquids and/or gas vs. gas competition – plus competition with other energy alternatives – to assess the feasibility and likelihood of the production volumes from each of "wedge" over the 2010-2050 timeframe.

The Data and Study Analysis Team evaluated a broad, diverse range of energy outlooks. A large proportion of the supply outlooks were developed by first determining the demand requirements (using economic growth and energy efficiency/intensity parameters as the main drivers), and then evaluating if/where domestic supplies or imports could match the consumption needs. Alternatively, some respondents utilized resource base models to determine the magnitude and duration of production plateaus without the benefit of in-depth analysis of the potential above ground and infrastructure limitations. Other institutions constrained their energy consumption to meet various carbon emission targets and thus the energy mix and hydrocarbon volumes were driven by this underlying assumption. In all of these these cases it's often impossible to determine if production volumes are resource and production-capacity constrained, and truly reflect the oil and gas supply capacity/capabilities of the United States and/or North America.

Therefore, given the difficulty of understanding the underlying assumptions and drivers for the collected industry outlooks, the data studies team and ICF International used its collective wisdom and capabilities to characterized three, comprehensive and integrated gas supply cases based on the ultimately recoverable resource and production capacity from each of the production wedges/areas above:

- A low-side case whose likelihood is high (occurs more than 90% of the time)
- A mid case that occurs about 50% of the time, and
- A high-side case whose probability is low (occurs less than 10% of the time)

We strongly believe that expanding this work to include oil/liquids cases, plus additional economic and carbon emission modeling could improve our understanding of the complex energy system and greatly augment the value of the three gas cases. Increased US natural gas production can have a multiplier effect in helping foster economic growth by creating jobs; increasing tax revenues for local communities and governments; reducing LNG (and if natural gas can be used more in the transportation sector) and oil imports, and thereby improving our foreign trade balance. This proposed work could be available to all stakeholders and help support a more transparent and fact-based framework to make the hard policy choices. We believe its essential to base these choices on in-depth analysis and interpretation of all the available data; open and candid dialog of the informed and diverse perspectives; and choosing the trade-offs between energy security, economic and environmental considerations that is required to provide the most affordable, clean and reliable energy for the consumers.

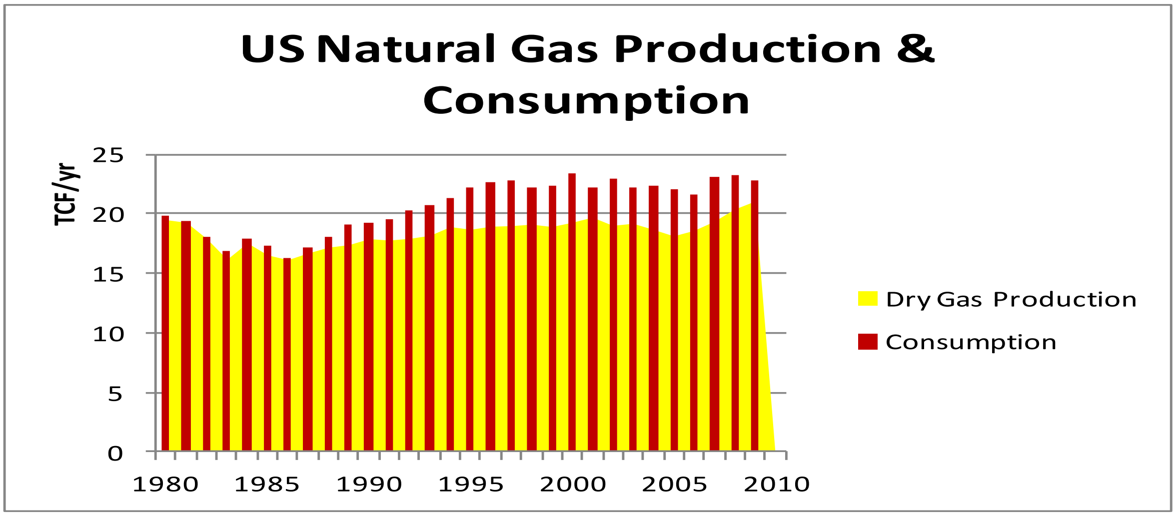
While the energy system is both complex and global (see Appendices 1 and 2), our goal was to provide a comprehensive, integrated, but yet understandable topic paper of the key elements of the oil and gas endowment/supply base (see below) for all potential audiences and stakeholders. While the focus is on oil and gas, all energy forms ultimately need to be considered given the interrelationships and competitiveness of the global energy markets and to provide meaningful insights and recommendations that ideally can move-the-needle and make a substantive difference.

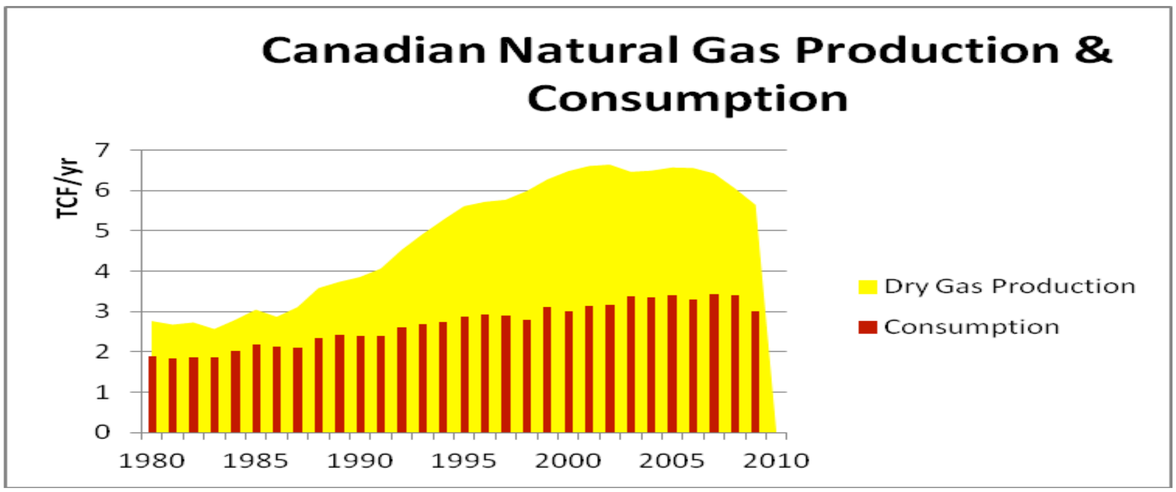
III. Gas Resource and Production History

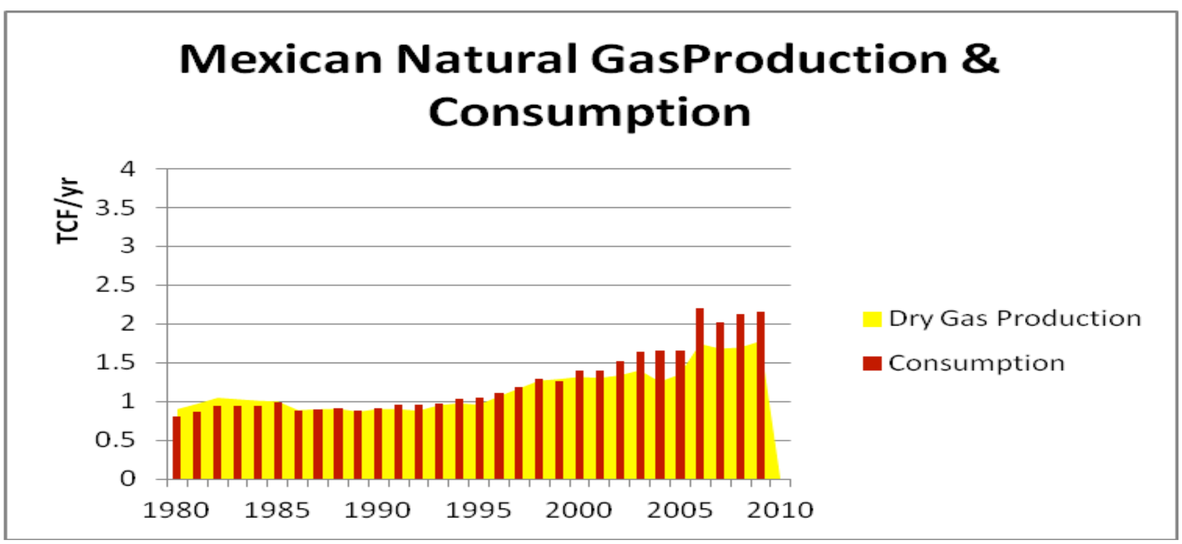
Most energy analysts in government, industry and public institutions believe the global gas resource base is more than adequate to meet demand over this study's timeframe (until 2050). Only about 20% of the 15,000 TCF of conventional global endowment has been produced to date, and our recent understanding of global coal bed methane, tight gas and shale gas reservoirs suggest the unconventional resource base could very large.
Regional natural gas supply patterns continue to shift. The marginal cost of indigenous supply in a region drives the import and export balance. As opposed to oil, which is a truly a global commodity, different dynamics and fundamentals are driving the North American, European and Asia Pacific gas markets. Outside of North America, gas imports (via long distance pipelines or LNG exports) from the large conventional gas resources of the Middle East, Australia, West Africa and Russia play a vital role in meeting consumption needs. Given North America's large gas resource endowment, plus supply and demand dynamics, there continues to be gas price disconnects between North America and the rest of the world. This is driven by the relatively lower (supply) cost of abundant domestic gas and the infrastructure network that connect supply hubs to consumers in North America, relative to large European and Asia Pacific domestic and regional markets that depend on foreign imports (typically longer term contracts linked with oil prices) to meet their consumption needs.

Historically, North American gas production has generally kept pace with growing consumption requirements. Canadian production has continued to exceed demand, while just in the past decade the US and Mexico has received LNG gas imports in addition to the pipeline gas from within North America to supplement their domestic supply base. As a result of technology advances and the emergence of the recent "game changing" shale gas plays, the gap between US demand and production is closing rapidly and likely to greatly reduce or eliminate the need for LNG imports.

Figure 8: Source – AEO 2011 Data







In light of this recent change in the North American gas sector, we plan to address the following questions:

- How big is the North America Unconventional Gas Resource Endowment?
- Can US and Canadian Unconventional Gas Production:
    - Reverse the potential decline of NA conventional gas production and satisfy future "reference or business as usual" demand growth needs?
    - Enable natural gas substitution for some coal and liquids in the power sector beyond a gas demand "reference" case?
    - Enable substitution for some liquid capacity in the transportation sector beyond a gas demand "reference" case?

Our focus is to understand the likelihood of increasing the US and NA production capacity given the many challenges, including:

- Size of the resource base
- Comparative costs to bring these volumes to market in light of other energy alternatives
- Infrastructure considerations
- Industry resources, capabilities, and capacity
- Materials and capital availability
- Environmental protection requirements
- Government policies
- Stakeholder issues

IV. Gas Resource Base and Endowment

We have limited the resource and reserve terminology to a few key terms and concepts, since a more detailed description of the definitions, fundamentals and assessment approaches/processes can be found in the Supply Resource Team's Topic Paper. In place resource and recoverable volumes (ranging from less than 10% to as much as 95% of the in-place) are fundamental elements of any discussion of endowment and overall energy supplies. The key consideration for all energy sources is converting the endowment into economically and commercially viable supplies. We need to beware of any possible resource misconceptions, and remember that:

- Resource estimates should reflect the full range of possibilities
- Do we fully understand all the assessment assumptions, vintage of estimate, and timing of resource availability?
- Resources do not always get bigger

- Technology breakthroughs don't always add significant volumes
- Not all barrels have the same economic value

North America contains both conventional and unconventional oil and gas resources. Until the last decade, most oil and gas estimates largely included conventional in place and recoverable volumes. The vast majority of the historical production from North America has been from conventional reservoirs and our understanding of both the in-place and ultimate recoverable conventional volumes is more advanced than unconventional accumulations because:

- There is abundant historical exploration and production data for conventional plays

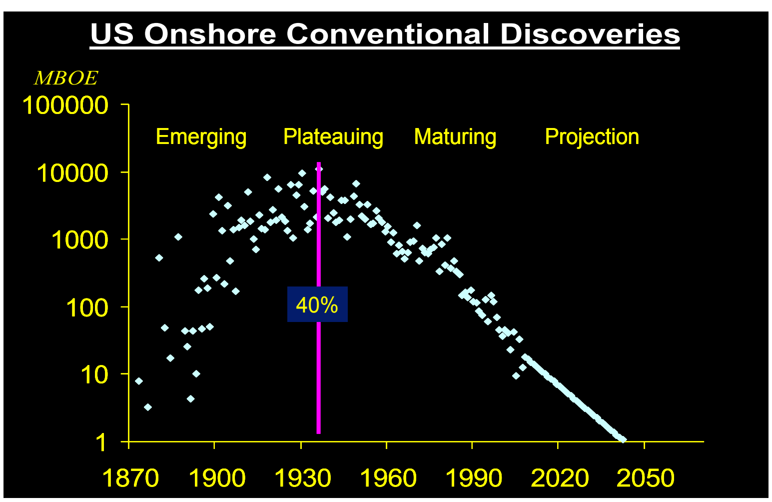
- Conventional plays are generally more mature in exploration "life cycle" (e.g. US conventional onshore plays)
  Hydrocarbon producing provinces have three discovery phases:
  - An early phase of large discoveries as the industry gets established
  - A plateau phase of maximum discoveries
  - A long slow decline as remaining resources are diminished

- Technology advancements have driven the pursuit of unconventional gas resources
  in the last decade

- Conventional volume estimates assessment methods are more established

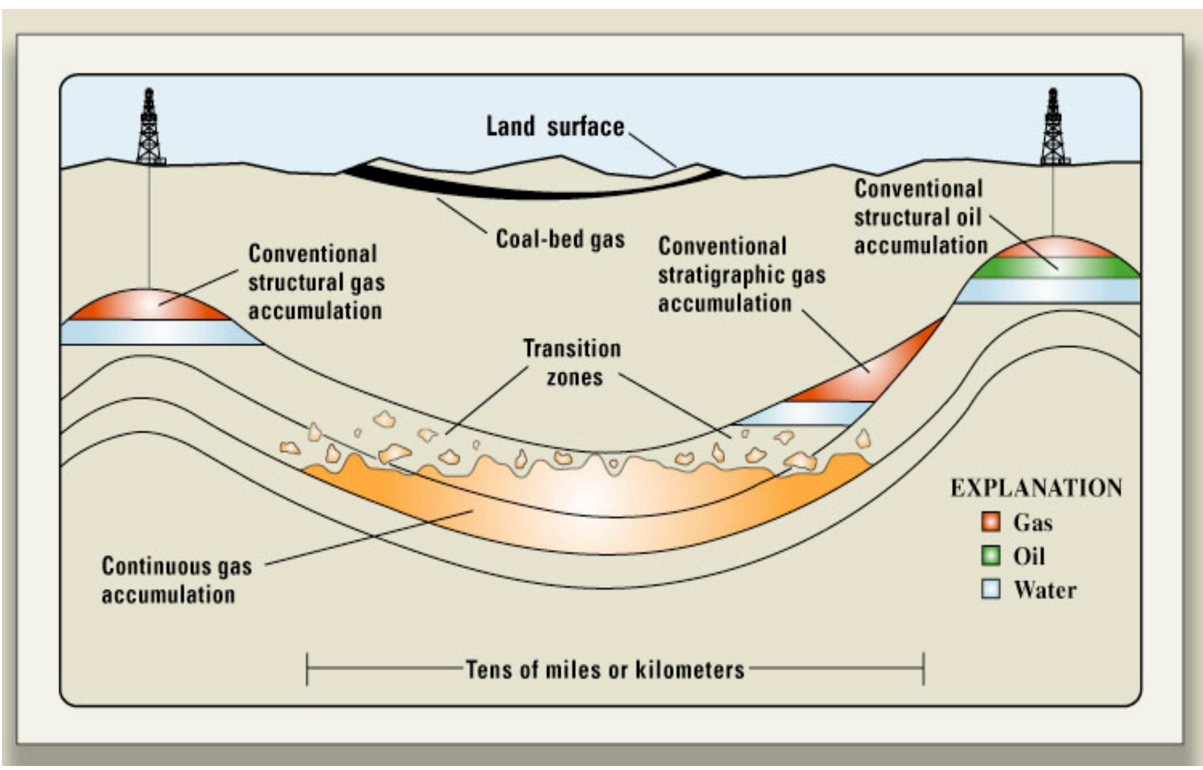
- Enhanced oil recovery (EOR) potential and effectiveness is greater and more understood in conventional reservoirs (e.g. enhanced permeability and oil quality)

Figure 9: Source – Keith King Illustration



The primary difference between conventional and unconventional reservoirs is the type of accumulation/trap. Conventional oil and gas is characterized by structurally, and less frequently, stratigraphically trapped accumulations with relatively permeable reservoirs that can be economically produced using “existing/known” technology. Many of the unconventional reservoirs are continuous accumulations (see below), with no underlying aquifer, which is different than conventional reservoirs. The unconventional gas and oil reservoirs have low matrix permeability (often less than 1 millidarcy) and, therefore, require the application and utilization of fracturing technology to create and expand fractures so oil and gas can flow in commercial quantities. Conventional oil reservoirs are also distinguished by the capability to be lifted and or pumped at reservoir conditions, whereas unconventional (heavy, oil sands, oil kerogen, etc) typically require processing or dilution to be produced. Moreover, unconventional oil reservoirs can require significant, additional energy utilization (gas, electricity, etc) to facilitate crude production, which decreases the overall net energy yield/gain from producing these resources. Our comprehension of the ultimate recoverable resource potential of unconventional oil and gas is less understood and most likely to change over time.

Figure 10: Source – Laramie Energy.Com



We have simplified the categorization of recoverable oil and gas resources from the in-place volumes into five easy categories:

- Produced Conventional and Unconventional Volumes
- Remaining Conventional Discovered – include both developed and undeveloped; future production is constrained by rate of development
- Remaining Conventional Discovered Growth – improved recovery in existing discoveries (e.g. water and/or CO2 floods, etc.)
- Conventional Undiscovered – restricted access and regulatory requirements can delay exploration; discovery pace drives production capacity
- Remaining Unconventionals – difficult to distinguish between what has been discovered vs. undiscovered in large, continuous accumulations and how to quantify growth potential. These can be transitional with conventional volumes, so we ensured no “double counting”

Over the past five plus years, many companies have capitalized on technology advances (especially for unconventional gas); relatively robust commodity prices (with considerable volatility); growing energy demand; and the availability of capital to expand their position and access to North America resources, which are largely “unconventionals”. As illustrated in the adjacent figure, the pursuit of North American growth opportunities is driven by the “size of the prize” and probability of achieving a good return on new capital investments. The impact of the recent economic downturn on commodity prices and their resulting volatility, curtailed demand growth, and a reduction of the financial liquidity of many E&P companies, threatens North America supply growth pace. In this study, unconventional gas types include coal bed methane, shale and tight gas; while the unconventional oil types are oil sands, oil kerogen (shale) and fracture-capable oil reservoirs (e.g. Bakken, Monterrey, Eagleford, etc.). We didn’t include gas hydrates (which is the subject of a separate white paper in the study) given our limited understanding of its commercial viability and if/when material production might occur in the foreseeable future.

While the size of the North America conventional resource base is relatively well understood and stable, our knowledge of the unconventional gas endowment is expanding rapidly given the increased industry activity and focus on shale and tight gas. We received relatively little data regarding the total North America resource endowment, largely since most institutions didn’t have or provide information on Mexico (which is the subject of a separate white paper in the study). Public data sources suggested that approximately 50 TCF has already been produced in Mexico, with remaining recoverable resource estimates of 50 to 200+ TCF. These estimates were primarily from pre 2005 vintage data sources and thus probably don’t reflect a recent assessment of the unconventional gas potential in Mexico.

The gas assessments of the ultimate, technically, commercially, remaining recoverable resource base for both Canada and United States varied considerably. This is largely a function of the vintage of the assessment and whether they included the most recent data and insights from the unconventional gas sector, especially shale gas. The ultimate remaining recoverable for the United States ranged approximately from 1,000 to 4,500 trillion cubic feet of gas, while Canada was 400 -1250 trillion cubic feet of gas. This wide range or recoverable resources results from the uncertainty of the ultimate recovery factors in the unconventional reservoirs. Given an annual consumption rate of approximately 30+ TCF in the US and Canada combined, the **resource base can meet demand requirements for another 50 to 150 years, but at what cost and sustainable growth rate?** The United States has produced around 1150 TCF which suggests it has consumed around 20% to 50% of the total domestic gas endowment based on the range of collected data. Canada has produced around 175 TCF which is around 10% to a third of its total gas resource base. If Canada solely utilized its domestic supplies for only internal demand requirements, this would be equivalent to 150 to 750 years of domestic supply.

The commercial development of gas resources into production is a function of the supply cost and prevailing commodity prices. Historically, industry has capitalized on the lowest "hanging fruit" and therefore, the development of the remaining conventional and unconventional resources are likely to become increasingly more costly and challenging. The adjacent historical US gas pricing illustration suggests the lower cost resources in the North American supply inventory have been produced in both the US and Canada. Technology can play a vital role in reducing supply costs and creating access to new regions, however continued development will require significant investment in new opportunities, infrastructure and the continued evolution of research and technology. Project viability assumes gas commodity prices will exceed investment and operating costs.

Figure 11: Source – Keith King Illustration

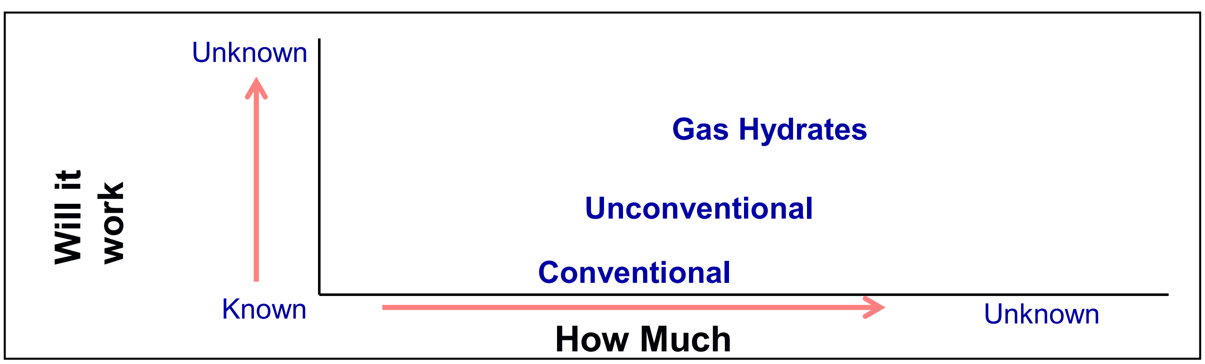


Figure 12: Source – EIA 2010 AEO

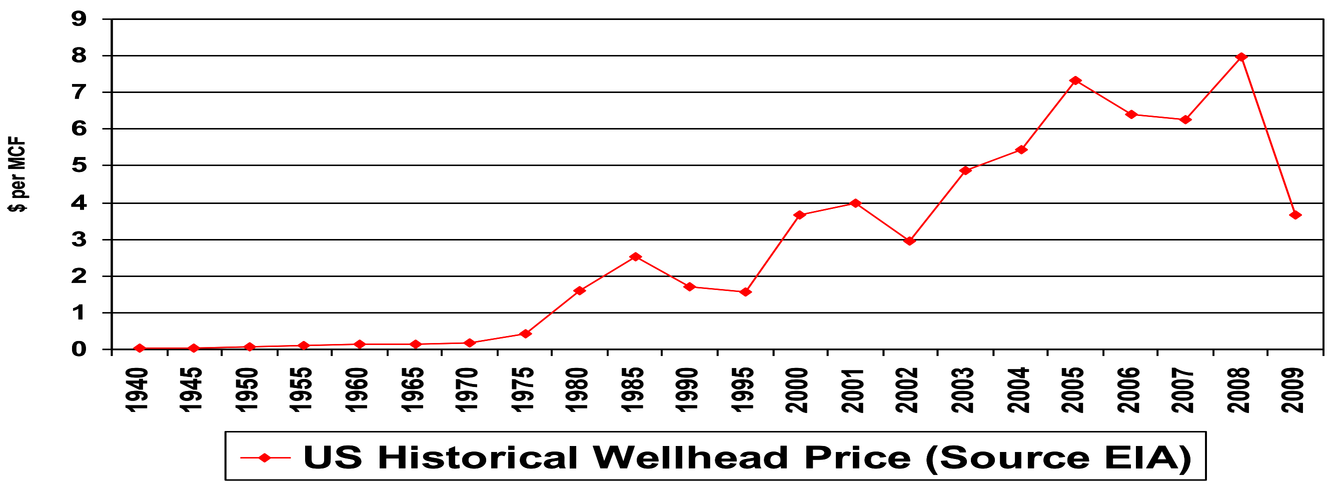
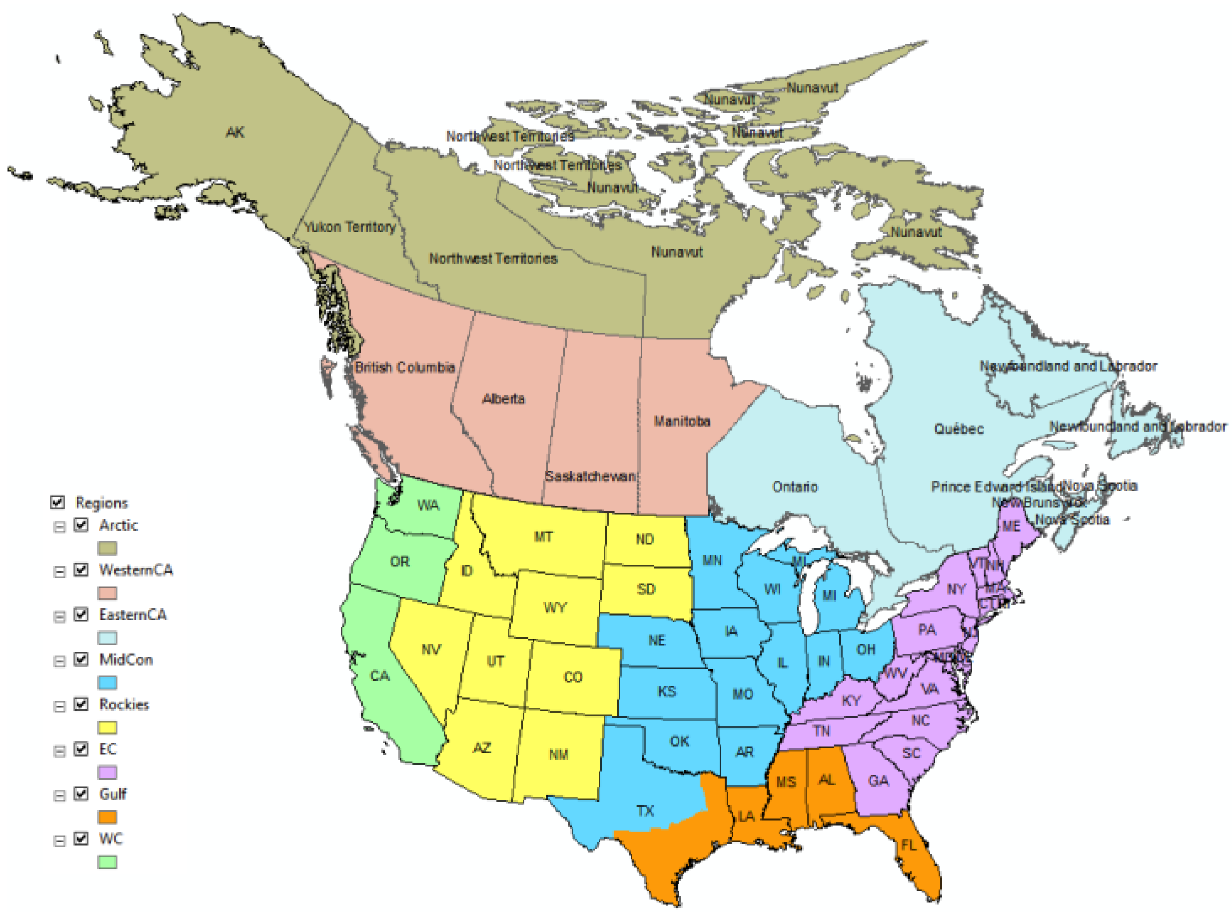


Figure 13: Source – NPC NA Study Geographic Scope



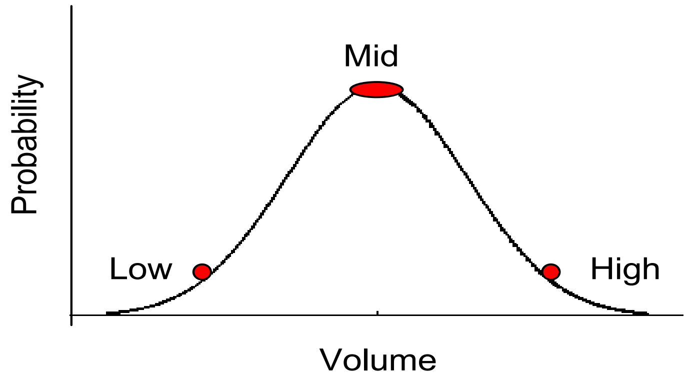
Please note: the US lower 48 (L48) and Canada were subdivided into the following gas types: conventional onshore, conventional offshore, coal bed methane, tight and shale gas. The Arctic regions in both Canada and US (Alaska) include both the onshore and offshore but only include the conventional volumes. The US and Canada onshore sub-regions are illustrated on the map and data was collected in the offshore for both the Atlantic and Pacific in Canada and the US and the Gulf of Mexico.

In Figure 14, we have included three industry scenarios that represent the results from the large range of outlooks we collected from publicly available and industry sources. While we received very few outlooks outside the low and high scenario values, we selected the above end members to represent the reasonable (around 10% likelihood) low-side and high side cases (see adjacent probability vs. volumes profile). In addition, we have also included the most recent US {Energy Information Agency (EIA) – utilizing USGS and BOEM data and augmenting wherever needed} and Canadian {National Energy Board – NEB} agencies estimates and the most recently available data from the Potential Gas Committee (PGC).

Figure 14: Source – NPC NA Oil and Gas Study Database

Trillions of Cubic Feet	PGC 2008 (10)	EIA 2011	Low Scenario	Mid Scenario	High Scenario
Produced			1140		
US Total* Remaining	2074 (2170)	2543	1500	2300	4000
Arctic	194	290	130	210	345
L48 Offshore Conventional	869	446	160	260	375
L48 Onshore Conventional		352	215	290	440
Tight Gas		455	200	350	550
Shale	616 (687)	862	700	1000	1800
(L48) CBM	99 (159)	138	90	120	150
Note: Low-High range based on spread of all data		NEB 2010	Low Scenario	Mid Scenario	High Scenario
Produced			175		
Canada Total* Remaining		1027	500	900	1250
Offshore Conventional		100	85	100	105
Arctic		116	45	75	125
Onshore Conventional		115	100	145	185
Tight Gas		104	40	70	100
Shale Gas (NEB doesn't include Montey)		82 (+>200-400+)	200	400	600
CBM		34	30	80	140

Figure 15: Source – Charlie Sheppard's Illustration of the Industry Aggregated Data Low, Mid and High Scenarios



Unfortunately, very few institutions submitted a comprehensive, integrated oil and gas resource data set. This may indicate that many organizations haven't dedicated the time or resources to develop a thorough understanding of the North American oil and gas endowment. Likewise, we also didn't receive an integrated, comprehensive, evergreen resource assessment from any particular US government agency, which also suggests that a common understanding or view may also be absent within the US government. We raise these observations in light of the *potential benefits and uses of resources estimates as pointed out in the NPC Hard Truths study (2006-07)* and our recommendation that there is a need for a more collaborative industry and government study or process, potentially together with academic institutions to 1) conduct, or 2) share, and/or 3) formally and periodically discuss national and regional basin/play oriented resource assessments:

- *Hydrocarbon resource assessments fill a variety of needs for consumers, policy makers, land & resource owners, investors, regulators involved in policy decision making.*
- *Industry use resource assessments to aid in:*
    - *Understand North America investments decisions within the context of global opportunity space*
    - *Portfolio Management*
    - *Corporate Strategy*
- *Governments use resource assessments to aid in:*
    - *Exercising stewardship*
    - *Estimating future revenues*
    - *Establishing energy, fiscal and social policies*

While there are limitations to what can be gained from any resource assessment, the data we collected from government, industry and the public sources provides a good starting point to enhance our understanding of the endowment fundamentals and the range of possibilities. Moreover, we found that some organizations provided very insightful, robust, recent assessments for particular sectors or regions in North America which they are focusing their efforts and investments. For example, the American Natural Gas Alliance (ANGA), a consortium of North American E&P companies, provided considerable data and contributions for unconventional gas. We believe the collected data from this study, which will be publicly available, can add value to recipients and provide a foundation for future studies.

What the Data Says

The **Canada conventional**, remaining recoverable resource base is approximately a third of the total remaining gas volumes in Canada and ranges from 230 – 415 trillion cubic feet (TCF) of gas (see above resource table). The industry mid scenario and the NEB (reference) cases were very similar (approximately 325 TCF). The range for the ***offshore*** region is relatively narrow at 85 – 105 TCF and almost all of the resources are located in the Atlantic. The range for the ***onshore*** region for the industry scenarios was 100 – 185 TCF, with relatively close agreement between the industry low and mid cases with the NEB reference case of 115 TCF. The remaining onshore gas volumes are located almost entirely in Western Canada. The greatest uncertainty for the conventional sector lies in the ***Arctic*** region, where there is considerably less historical data and understanding of the ultimate potential. The NEB estimate of 116 TCF was at the high end of the industry range of 45 – 125 TCF. The Arctic areas with the largest remaining potential include the Beaufort/MacKenzie (~60 TCF) and the Sverdrup – Arctic Islands (~35 TCF).

The **Canada unconventional**, remaining recoverable resource base is approximately two thirds of the total remaining gas volumes in Canada and ranges from 270 – 840 trillion cubic feet of gas. The NEB and industry believe there is around 150 TCF of remaining recoverable resources in ***coal bed methane*** and ***tight gas*** reservoirs in the mid/reference cases. Additionally, the incremental upside for CBM plus tight gas in the industry high scenario was less than 100 TCF. These plays types are located almost entirely in Western Canada and proximal to the existing infrastructure/network. While some of the remaining potential can be brought on-line within today's cost and price environment, we also believe a material proportion of the remaining volumes may lie in small field/marginal well fractions and/or higher supply cost areas (deep, etc.).

***Canadian shale gas* is a potential game changer**. The industry estimate of remaining recoverable resource potential estimates of 200 – 600 TCF could be almost half of the remaining gas resource potential for Canada! This play is in the early exploration phase and thus we can expect the "mean" or most likely values and the range to be further constrained as we get additional well and production performance data over the next decade. Whereas in conventional reservoirs where as much as 95 per cent of the natural gas can be recovered; the ultimate recoverable volume from shale reservoirs may be to be up to 20 - 30% of the in-place, with recovery factors in poor quality reservoirs/results below 10%. Cretaceous, Jurassic, Triassic, Mississippian and Devonian shales are potential targets with the largest resource potential located in Western Canada See (below map and table).

Figure 16: Source – Canadian Association of Petroleum Producers

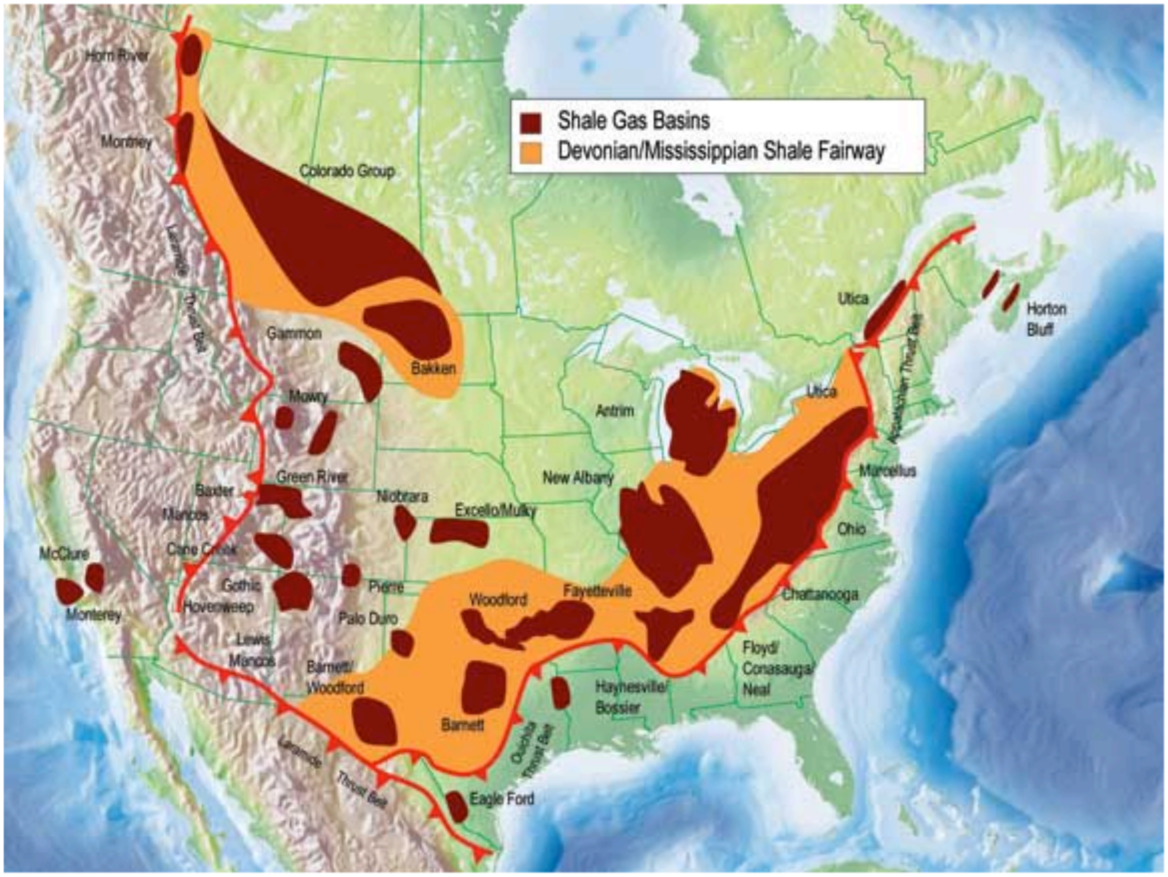


Figure 17: Source – NPC North America Study Database

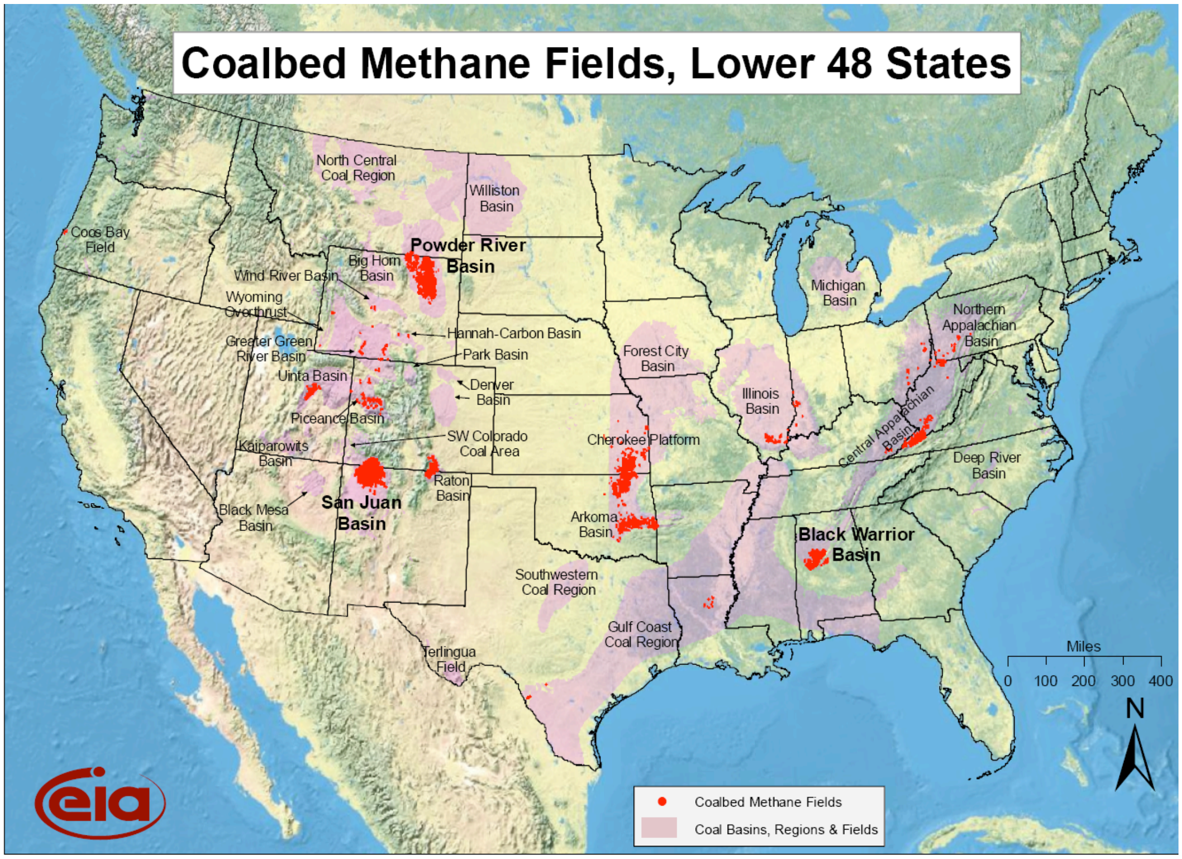
Canadian Shale Gas Most Likely (Mean, Average, etc) Resources (TCF)		
Regions & Plays	**Range for NEB 09, CUSG 10 and ANGA 10 Estimates**	
	In Place	**Recoverable**
Montney (Alberta and BC)	**550 – 720**	**32 - 337**
Horn River	**400 - 600**	**75 - 120**
Cordova Embayment	**40 - 200**	**3 - 68**
Utica	**50 - 180**	**7 - 42**
Maritimes	**25 – 130**	**1 - 50**
Colorado Group (WCSB)	**100**	**4 - 14**

The **United States conventional**, remaining recoverable resource base is around 25 to 40 % of the total remaining gas volumes in the US and ranges from 515 – 1160 trillion cubic feet of gas. The current EIA (2011 reference) assessment of over 1 Quad (equivalent to 1000 trillion cubic feet) of gas is at the upper end of the industry estimates and may suggest a difference of views regarding the technical and commercial viability of some of the remaining conventional resource base, especially considering the 2010-50 production timeframe for this study. The EIA and industry have a relatively similar view of the ***onshore*** region, with the low and mid cases for industry ranging from 215 - 440 TCF and the EIA (2011 reference) was 345 TCF. This is probably the most mature exploration and production area in North America. The industry remaining recoverable resource range for the ***offshore*** region was 160 – 375 TCF and the EIA (2011 reference) was 445 TCF. The vast majority of the remaining resources are located in the Gulf of Mexico with estimates ranging from 200 – 300+ TCF, with the Pacific and the Atlantic Coast each around 20 - 30+ TCF. The 2011 EIA reference case of the ***Arctic*** remaining recoverable gas of 290, whereas the industry's range was 130 – 345 TCF and the PGC (2008) assessment was 194 TCF. The largest remaining recoverable resources in the Arctic are located in the North Slope and include the approximately 35+ TCF already discovered, plus the additional exploration and growth potential bringing the total potential to over 100 TCF. The Chukchi OCS (~90 TCF), Beaufort (~30 TCF), and Bering Shelf (~20 TCF) also may contain material gas resources. Finally, various consultants (ICF 2008, SAIC/GTI 2010), at the request of the US government agencies, have estimated between 100 – 300 TCF of the remaining recoverable gas in the United States is located in moratoria areas, with 100+ TCF in the L48 offshore and onshore (largely Rockies) and up to 20+ TCF in the Arctic. The offshore and Arctic gas resources in the moratoria areas are all in conventional reservoirs.

The **United States unconventional**, remaining recoverable resource base is around 60 to 75% of the total remaining gas volumes in the US and ranges from 990 – 2305 trillion cubic feet of gas. The most recent EIA estimate for remaining unconventional recoverable gas is over 1 Quad with industry's mid scenario around 1400 TCF (1.4 Quads).

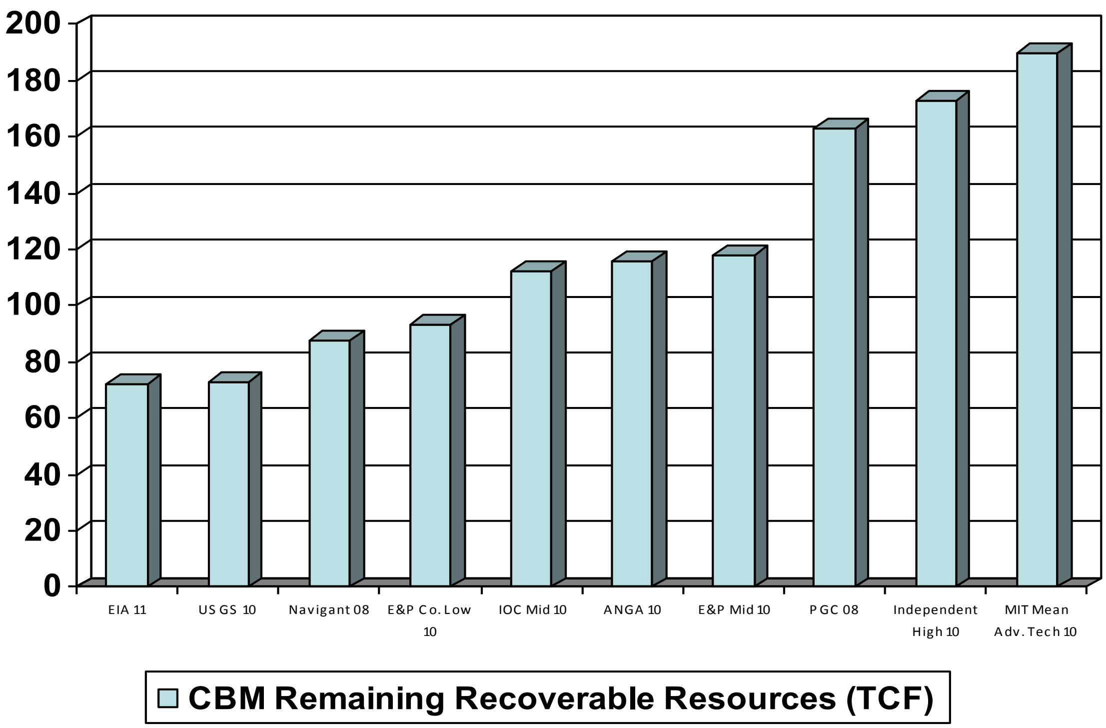
The Lower 48 is estimated to have in-place, ***coal bed methane*** resources of 700 trillion cubic feet (TCF), of which the remaining, economical resource base ranges from 70 – 150 TCF with an expected value/most likely of 100 – 120 TCF. CBM is a relatively small component of the total unconventional gas resource base. The vast majority of the coal bed methane recoverable resources are located in the Rockies (50 – 90 TCF) in the San Juan and Powder River basins; with the East Coast, Gulf Coast and Mid-continent regions ranging from 5-10+ TCF each.

Figure 17: Source – EIA



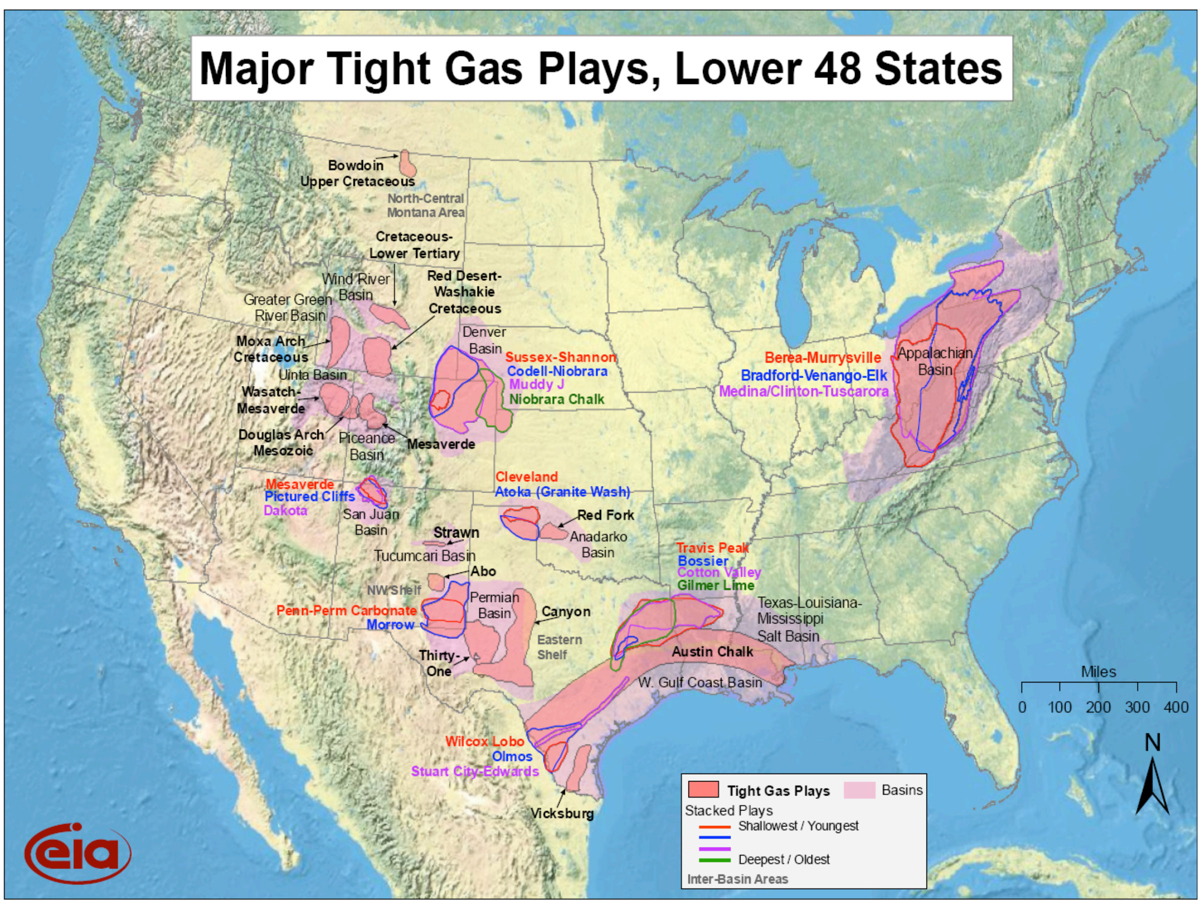
Source: Energy Information Administration based on data from USGS and various published studies
Updated: April 8, 2009

Figure 18: Source – NPC North America Study Database



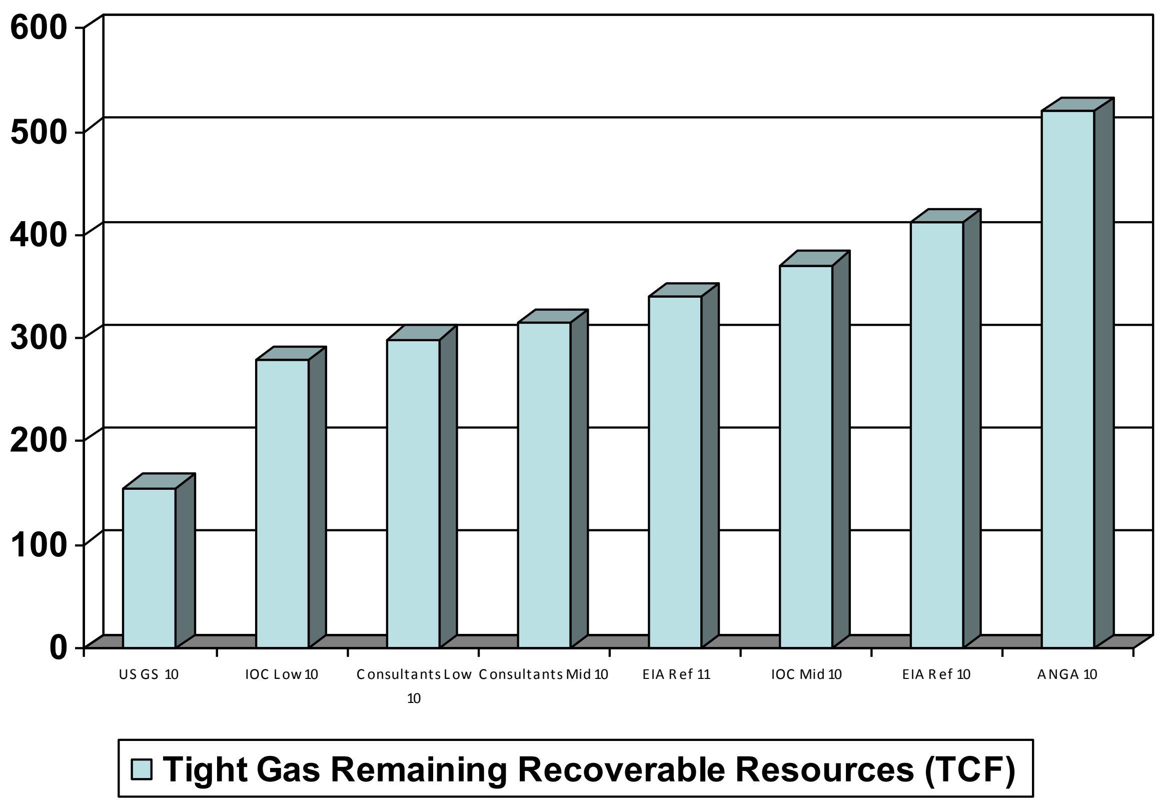
The ***tight gas*** remaining recoverable EIA 2011 reference and mid industry scenario is around 350 – 450 TCF, with a range of 200 – 520 TCF. Approximately 120 TCF of tight gas has been produced, which leaves anywhere from 65 – 85+% of the resource base that is yet to be developed and can contribute significant annual supply volumes towards future North America gas demand. The largest remaining resources are in the Rockies (with expected value/most likely estimates around 200+ TCF), largely in the Greater Green River, Uinta, Piceance and San Juan basins. There is also material (in excess of 50+ TCF) resource potential in the Gulf Coast (e.g. Mesozoic plays in East Texas and South Texas Tertiary plays), East Coast (e.g. Appalachia), and Mid Continent (e.g. Granite Wash) regions. Please note that in graph below and for other unconventional gas resource assessments, the USGS estimate may only represent the undiscovered and growth estimates instead of the total remaining as listed for all the other organizations. This is especially significant given the difficulty discriminating between what is proved/discovered in coal bed methane, tight gas and shale gas plays as opposed to what remains undiscovered or is in the future growth (ultimate recovery assessment – discovered recoverable volume) categories.

Figure 19: Source – EIA



Source: Energy Information Administration based on data from various published studies
Updated: April 8, 2009

Figure 20: Source – NPC North America Study Database



Many organizations and institutions have increased their assessment of the United States gas resource base, with the vast majority of the growth resulting from shale-gas plays in the Appalachian basin, Mid-Continent, Gulf Coast and Rocky Mountain areas. ***United States shale gas* is a potential game changer, with most recent industry assessments ranging from 700 – 1800 TCF, with the EIA reference and industry mid case around 1 Quad (1000 TCF).** As you can see from the below EIA chart and the following comments made during the release of the 2008 Potential Gas Committee report, shale gas has been the predominant cause for renewed optimism about the US gas resources and supplies for the future:

Figure 21: Source – EIA

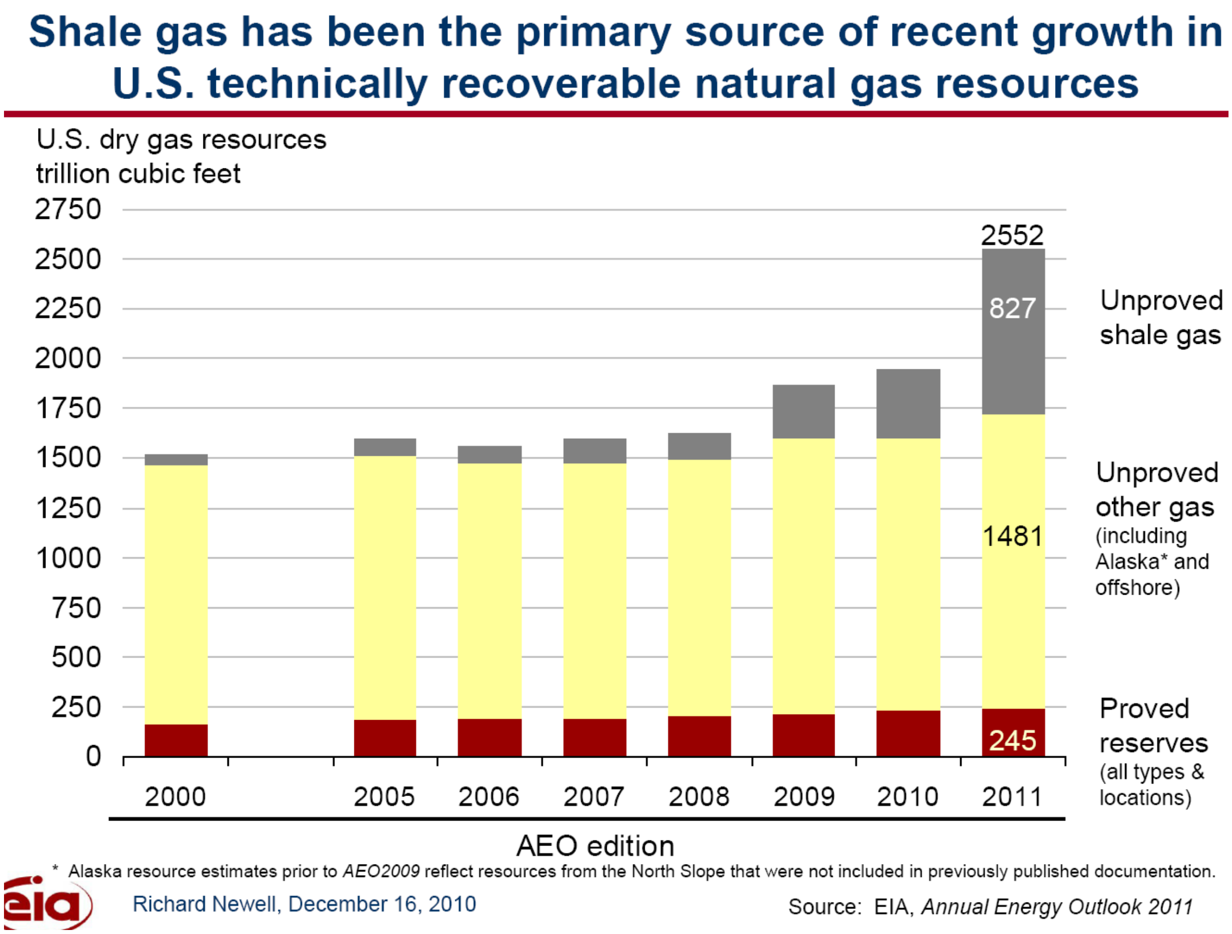


Figure 22: Source – Potential Gas Committee Press Release

Potential Gas Committee reports unprecedented increase in magnitude of U.S. natural gas resource base

GOLDEN, Colo., June 18, 2009 – The Potential Gas Committee (PGC) today released the results of its latest biennial assessment of the nation's natural gas resources, which indicates that the United States possesses a total resource base of 1,836 trillion cubic feet (Tcf). "The PGC's year-end 2008 assessment reaffirms the Committee's conviction that abundant, recoverable natural gas resources exist within our borders, both onshore and offshore, in all types of reservoirs," said Dr. John B. Curtis, Professor of Geology and Geological Engineering at the Colorado School of Mines and Director of the Potential Gas Agency there, which provides guidance and technical assistance to the Potential Gas Committee.

Dr. Curtis cautioned, however, that the current assessment assumes neither a time schedule nor a specific market price for the discovery and production of future *gas supply. "Estimates of the Potential Gas Committee are 'base-line estimates' in that they attempt to provide a reasonable appraisal of what we consider to be the 'technically recoverable' gas resource potential of the United States," he explained. When the PGC's results are combined with the U.S. Department of Energy's latest available determination of proved gas reserves, 238 Tcf as of year-end 2007, the United States has a total available future supply of 2,074 Tcf, an increase of 542 Tcf over the previous evaluation. As Dr. Curtis observed, "Our knowledge of the geological endowment of technically recoverable gas continues to improve with each assessment. Furthermore, new and advanced exploration, well drilling and completion technologies are allowing us increasingly better access to domestic gas resources —especially 'unconventional' gas—which, not all that long ago, were considered impractical or uneconomical to pursue." "Consequently, our present assessment demonstrates an exceptionally strong and optimistic gas supply picture for the nation."*

The recent paradigm shift in the North American gas outlook is underpinned by the increased size and availability of the shale gas resource base. Just a few years ago, many industry pundits believed the US was going to become increasingly dependant on liquefied natural gas (LNG) imports. The development and application of new technology in the last decade led to relatively low cost coal bed methane resource base development in the San Juan and Powder River basins, then Rockies tight gas, and recently the very large resource increase for shale gas within the Barnett Shale. This was quickly followed by other shale gas plays like the Fayetteville, Woodford, Marcellus, Haynesville and Eagleford.

Figure 23: Source – NPC North America Study Database

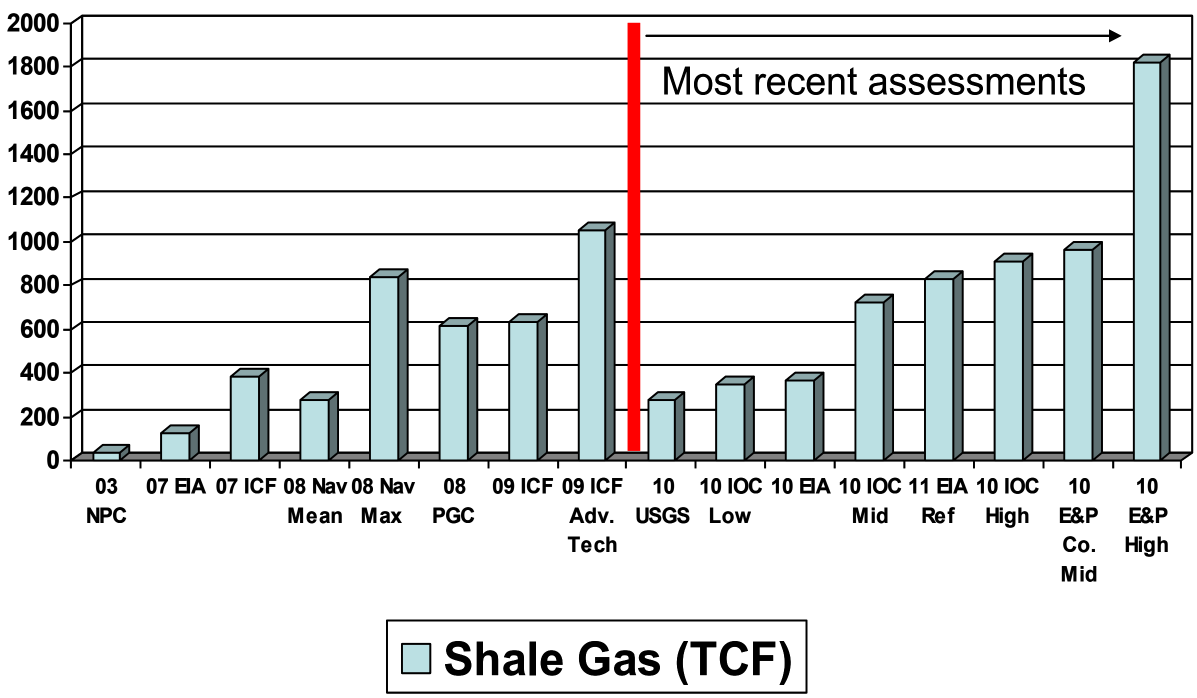
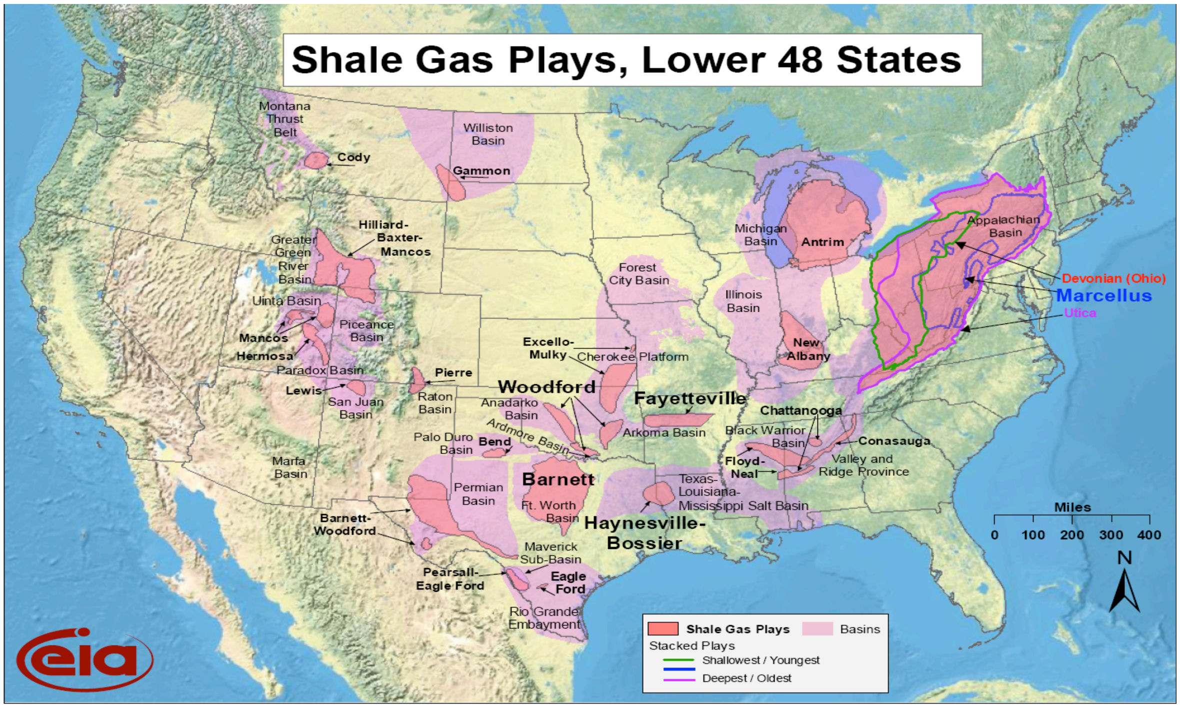


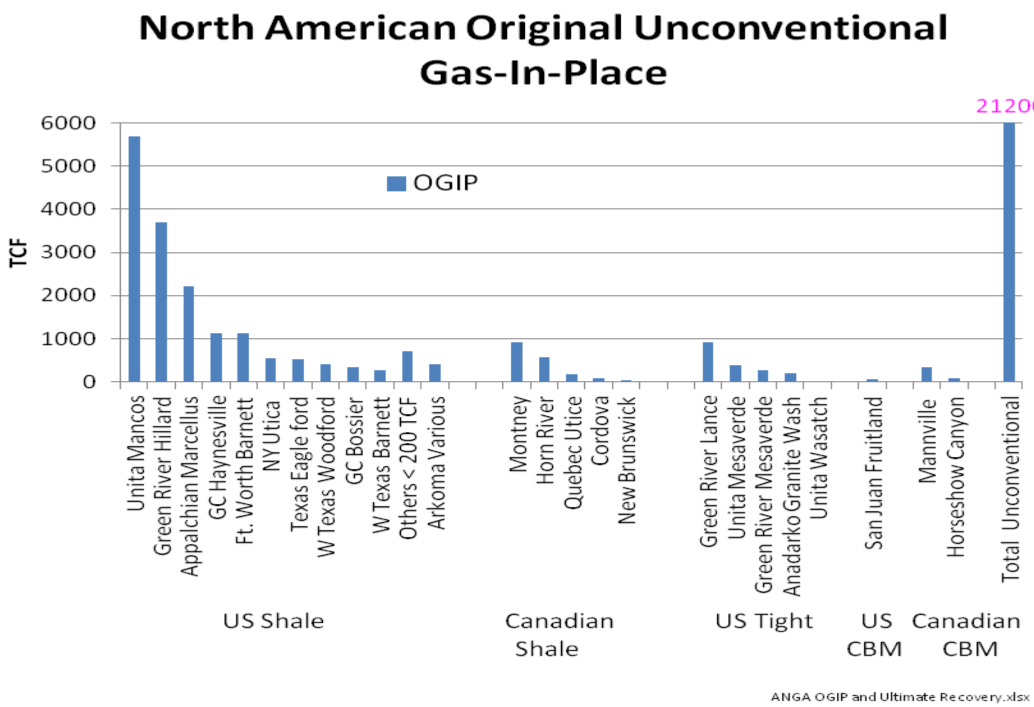
Figure 24: Source – EIA

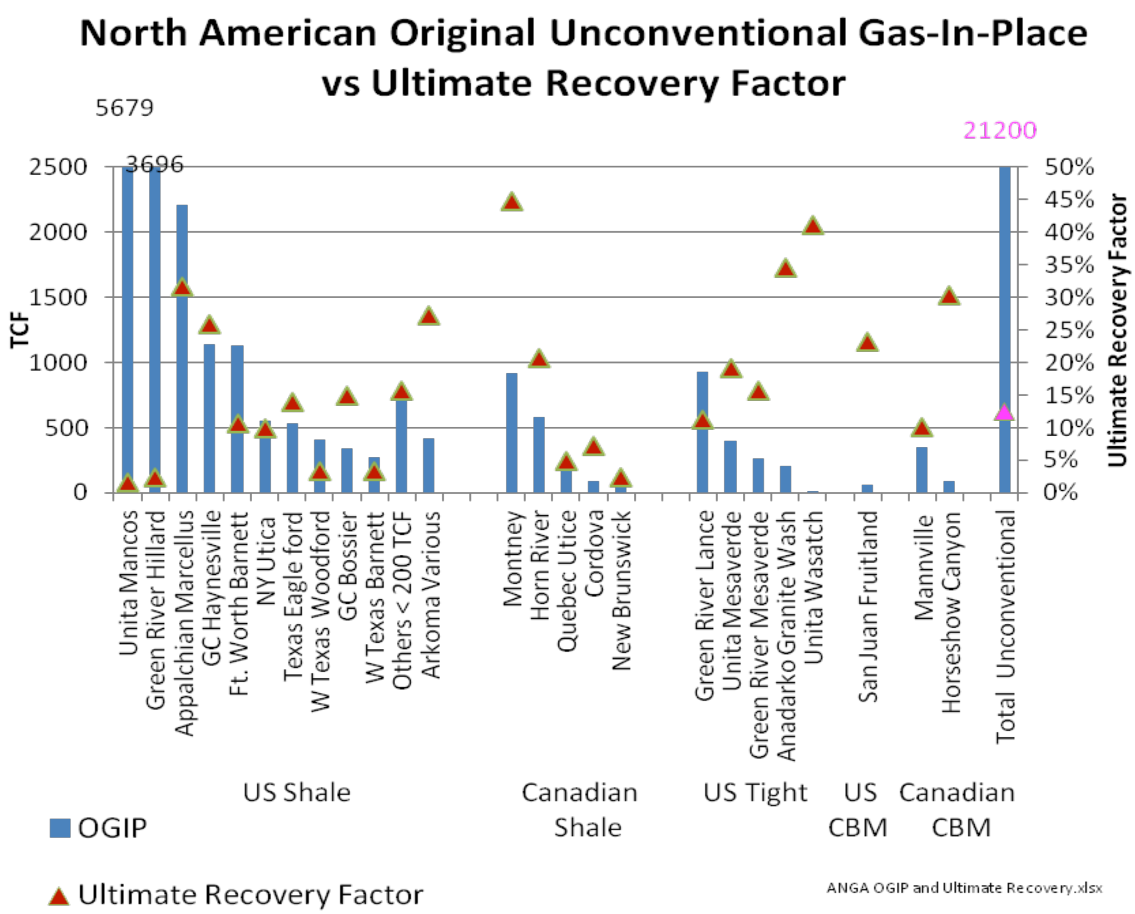


Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010

In 2010, ANGA and ICF estimated the in place resource volumes for many of the US and Canadian unconventional gas plays to be in excess of 20,000 TCF, however the ultimate recovery factor for the plays ranges from 5 – 40+%. The shale gas in place volumes were based on geoscience data and maps which included the net thickness, organic content and thermal maturity assessments provided to ICF by the twenty plus ANGA companies. In light of the difference in rock properties for the various shale plays, the recovery factors ranged from less than 5% for the Woodford and Barnett in West Texas, Unita Mancos and Green River Hilliard to possible as high as 30% over time for the Marcellus. Clearly, further technology advances could enable more gas to be recovered from the large unconventional gas endowment and provide additional resource base growth. However while the in place volumes for shale gas are large, the cost to develop these resources is a key component of the supply equation.

Figure 25: Source – American Natural Gas Alliance Study





The geographic distribution of shale gas supplies, together with location of the other conventional and unconventional plays, suggest that most regional, as well as the national US and Canadian gas markets, could have a self-sufficient gas supply source in the foreseeable future. This will ultimately depend on the supply cost at the wellhead plus transportation costs, but we are beginning to see growth in some (e.g. East Coast) regional supply chains given the recent availability of new, large shale gas resource plays. Historically, domestic gas supplies and large processing facilities have largely been situated in the Gulf Coast, Rockies, Mid-continent and western Canada, with US imports coming from western Canada and LNG imports primarily landing in the Gulf Coast. We believe there will be a shift in the US and Canada supply chain network over the next 10+ years as industry gas exploration and production activity is focused on the most profitable (likely lowest supply cost gas) opportunities and midstream companies link new supply hubs with regional markets. Already, we see Marcellus shale gas penetrating the northeast US market and fetching premium prices due to its reduced transportation cost relative to Henry Hub.

Figure 26: Source – NPC North America Study Database

US Shale Gas Most Likely (Mean, Average, etc) Recoverable Resources (TCF)	
Regions & Plays	**Range for Navigant 08, PGC 08, EIA 11, ANGA 10 Estimates**
East Coast	**70 – 613**
Gulf Coast	**90 – 350**
Mid- Continent	**110 - 205**
Rockies	**45 - 75**
Marcellus	**177 – 546**
Haynesville	**34 – 251**
Eagleford	**20 - 68**
Barnett (Fort Worth Basin)	**26 – 168**
Fayetteville (Ark. & Okla.)	**21 – 52**
Woodford (Ark & Okla.)	**12 – 28**
Mancos (Unita)	**11 - 21**

In summary, the apparent abundance of US and Canadian natural gas resources raises the question of the merits of a potential shift in US and North America energy consumption towards natural gas. Natural gas utilization yields lower carbon emissions than coal (45%) and oil (30%) and thus can help serve as a bridge to a lower carbon future. The large North America gas endowment will likely have an impact on the future energy mix, especially in the power and transportation sector where gas has the capability to displace some coal and liquid sources?

V. Gas Production Capacity and Outlook

The previous 2003 NPC North American Gas and the 2006-07 Global Energy studies concluded that it will be increasingly difficult to avoid declining conventional gas production. The 2003 study noted the accelerating field decline rates, decreasing size of new conventional discoveries and higher finding/development costs for deep (e.g., high temperature and pressure) reservoirs lead to this conclusion. Both of these NPC studies recognized three supply areas that were the key to satisfying future demand requirements, including (1) domestic unconventional plays; (2) Arctic gas; and (3) increased LNG imports. While we still believe these "sources" are still the foundational elements for NA supply, the timing, magnitude and relatively importance of each over the study timeframe of 2010-50 has changed considerably. Both previous studies suggested LNG and Arctic volumes would play a large role in future NA supplies in the near and mid term. The 2003 NPC study contemplated LNG imports and Arctic pipeline gas from both long distance Mackenzie & Alaska pipelines contributing over 5 TCF/YR in by 2015, whereas the 2006-07 Hard Truth Energy study reported that the various forecasts at that time suggested that by 2030 up to 18% of the US gas market could be supplied by LNG (5-6 TCF/YR) and the Mackenzie and Alaska pipelines would be operational and providing in excess of 2+ TCF/YR.

The outlook for the United States and North American gas production has changed dramatically in just the past few years. The gas resource base in both the US and Canada is believed to have increased significantly and will have profound impact on the NA energy markets from a pricing, energy security and environmental standpoint. Each of the production cases in the table below were developed from of an integrated energy outlook in which the NA gas demand was determined based on economic growth, energy efficiency and business environment assumptions. The EIA and IEA 2010 outlooks indicate that the majority of demand growth in the reference and modest growth cases can largely be met with NA supplies. If we also include industry supply scenarios for all of ***North America***, this suggests there is an **ample "supply base" for the modest demand scenarios as well as high gas consumption cases**. The gas resource base does not appear to be the limiting factor on bringing new NA supplies to market, but rather possible challenges associated with converting resources into production capacity.

US and Canadian import and or gas export levels will likely be driven by cost of supply and logistical (getting gas to consumers) considerations rather than from an energy security perspective. The pace and cost of increasing unconventional production in North America will impact LNG activity, with the lowest cost imports to continue landing in existing US and Mexico terminals unless these cargos are diverted to international markets with much higher netbacks/price realizations. Ultimately the pace and mix of increased unconventional production, LNG imports and the large investment needed to construct long distance pipelines from the US and Canadian Arctic will be a function of the marginal cost of gas supply, since consumers will be seeking the lowest cost, reliable, secure energy supplies.

Figure 27: Source – NPC North America Study Database

Modest North America Growth Demand Cases (TCF/YR)						
	2007	2015	2020	2025	2030	2035
IEA 2010 WEO Future Policies	28.2	29.2	30.1	30.8	31.6	32.6
EIA 2010 IEO Reference	28.2	27.4	29.6	30.7	32.9	34.9
North America Gas Production Cases (TCF/YYR) - 2010 Vintage						
IEA 450	27.4	26.8	27.1	27.5	27.9	28.1
IEA Future Policies	27.4	27.7	28.6	29.0	29.5	29.9
IEA Current Policies	27.4	28.0	28.6	29.2	29.7	30.2
Industry Unidentified	27.4	28.3	30.0	30.8	30.6	
EIA Reference	27.4	26.9	27.7	29.3	31.0	32.2
EIA High Economic Growth	27.4	27.4	28.9	31.0	32.9	33.9
Industry Unidentified Scenario	27.4	29.6	29.2	33.6	35.6	
Industry Unidentified Scenario	27.4	28.4	32.0	35.9	40.0	

What the Data Says

Mexico is not expected to contribute to North American natural gas production growth. The industry cases in the table below suggests that ***Mexican gas*** production is likely to decline over this decade until investment and the development of new gas resources may bring production up above 2 TCF/YR by 2030 (maximum of 2.4 TCF/YR)? Almost all of the below EIA and IEA forecasts below had Mexico production growing modestly above the 2008 production levels of 1.7 TCF/YR with the pace and magnitude (maximum of 2.4 TCF/YR in 2035) varied in the five cases.

The 2010 EIA IEO reference case projected that Mexican gas demand would grow considerably from 2.4 TCF/YR in 2007 to 5.4 TCF/YR by 2030. This suggests that imports will be required to meet these growth aspirations and needs. Energy ministry Sener noted that Mexico's domestic gas supply is insufficient to meet growing demand and in its most recent gas forecast said it expects imports to rise 5.2% a year and reach 3 BCDF by 2024. Two LNG regasification terminals have started service, including Sempra Energy's Costa Azul plant in Baja California State and the Altamira plant on the Gulf of Mexico coast owned by Shell, Total and Mitsui. Construction of Mexico's third terminal, Manzanillo, is underway and it will start operations in September 2011. Mexico may look to the US or develop new domestic unconventional resources (e.g., Burgos basin?) rather than import LNG, especially since unconventional gas supplies may be less expensive than LNG supply sources. Gas imports from the US will be highly dependent on whether Mexico has the pipeline infrastructure capacity and capital availability to deliver the gas where needed.

Figure 28: Source – NPC North America Study Database

Mexico Gas Production Cases (TCF/YYR) - 2010 Vintage						
	2008	2015	2020	2025	2030	2035
Industry Unidentified	1.7	1.4	1.4	1.3	1.8	
Industry Unidentified	1.7	1.5	1.4	1.4	2.0	
IEA 450	1.7	1.7	1.7	1.9	2.1	1.9
EIA Reference	1.7	1.9	2.1	2.1	2.1	2.1
EIA High Economic Growth	1.7	2.1	2.1	2.1	2.1	2.1
IEA Future Policies	1.7	1.7	1.9	2.0	2.2	2.3
IEA Current Policies	1.7	1.8	1.9	2.1	2.3	2.4
Industry Unidentified Scenario	1.7	1.6	1.4	1.9	2.4	

Figure 29: Source – PEMEX

As a result of the expected limited gas production growth, we didn't consider Mexican gas as a critical part of the North American supply and demand outlook in our analysis.

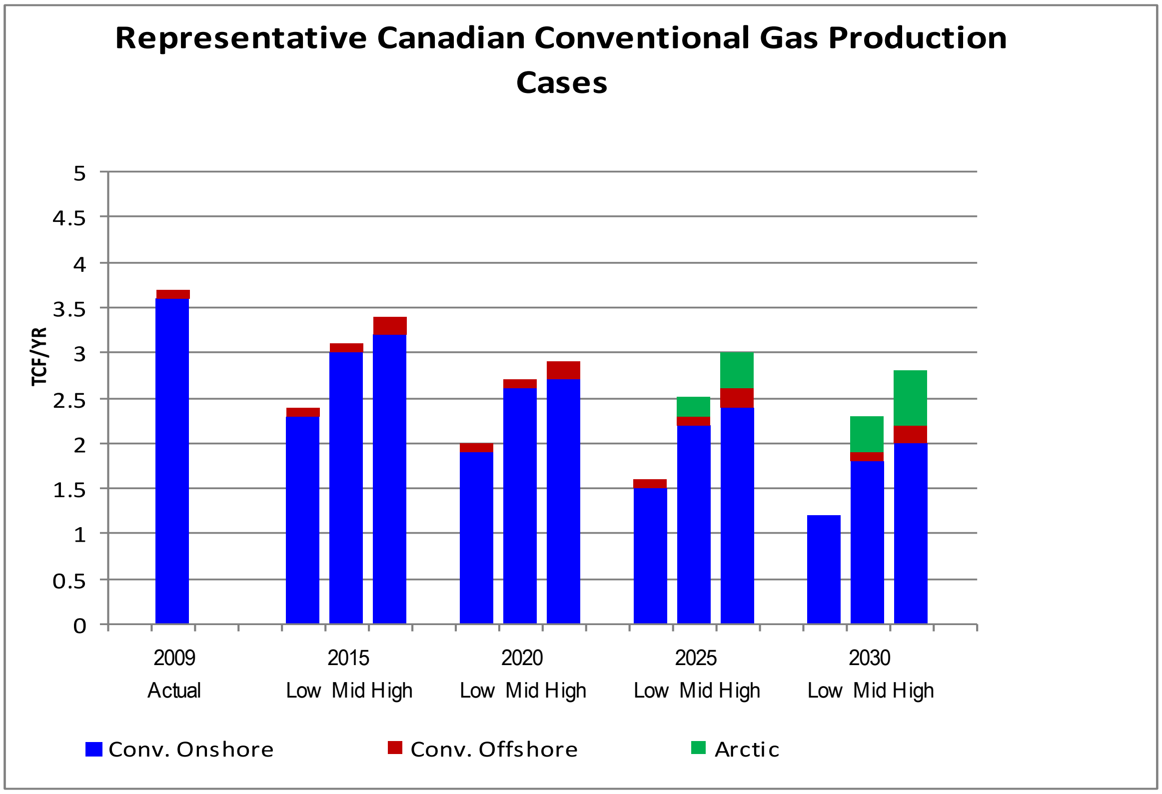
For the United States and Canada, over 25 industry templates were submitted and then aggregated into twelve cases provided there were 3 responses each for the consultant, IOC, E&P plus the IOC & E&P categories. We selected a low, mid and high case to illustrate the range of responses.

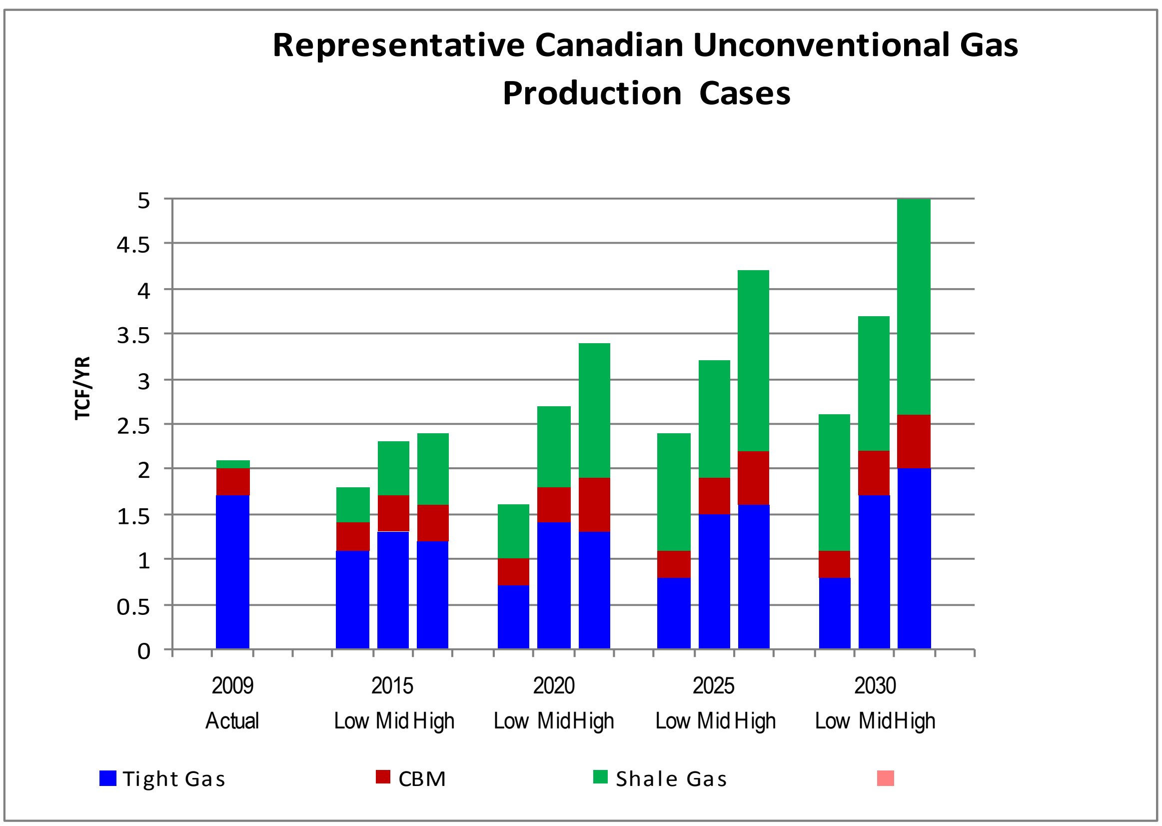
In all cases in Figure 30, the ***Canadian onshore conventional*** sector production output is expected to decline over the next 20 years and continue the trend of declining (in excess of 1+ TCF/YR) production seen over the last ten years. These supplies are almost entirely in Western Canada and we anticipate that industry will continue to maximize the ultimate recovery from these assets and infrastructure; however most of the new conventional additions will be small pool sizes adjacent to existing fields or infill drilling projects that will maximize recovery. The rate of decline in the existing reservoirs and fields in Western Canada is greater than 10% per annum. Without large, new discoveries, it will be impossible to reverse this trend of declining production. Deep, high pressure, and/or sour gas remaining resources and opportunities are likely to higher finding and development costs and may not attractive investment in light of alternative lower cost unconventional plays in the area.

The future gas production capacity from the ***Canadian offshore*** (Atlantic) is believed to be relatively small (less than 0.2 TCF/YR). Unless large new discoveries are made in the Atlantic (e.g. Orphan basin), this area is unlikely to have a material impact on Canada's conventional production capacity.

The only area which can provide substantive new volumes is the ***Arctic***; however there is considerable diversity of views as to when this generally "higher" cost gas will enter the market. The anticipated Mackenzie gas project timing has slipped considerably since the first NPC North America gas study in 1999, largely a result of the cost competitiveness of these supplies with alternatives, plus the challenges associated with building a large export pipeline from the discovered fields (with significant follow-up potential in the Arctic) down into the existing Western Canada infrastructure.

Figure 30: Source – NPC North America Study Database





Unconventional gas production is expected to offset the overall decline for the conventional sources in Canada. While tight gas and CBM are expected to maintain their current production volumes, **it is shale gas that will significantly grow in production** from the 0.1 TCF/YR to 1.5 (low) – 2.4 TCF/YR (high) by 2030. ***Coal bed methane*** production is anticipated to be between 0.3 TCF/YR to 0.6 TCF/YR in the above scenarios by 2030. While its difficult to distinguish the transition from conventional to tight gas reservoirs in Western Canada, the perception is that there is more remaining resource potential at current cost and price levels to exploit tight gas in the study timeframe, than conventional sources.

All the outlooks collected indicated that Canadian gas production will exceed even the largest internal demand requirement scenarios (up from 2.8 to 4 TCF/YR), and, therefore, the main driver for Canadian output will be "pull" from the United States and other export markets. Most forecasts suggest that without shale gas and in some instances Arctic gas production, Canadian gas production is likely to continue to decrease from historical levels. Both the industry "mid" and reference cases indicate that Canadian conventional, tight gas and CBM supplies would likely decline to *around* 4 TCF/YR by 2025. The industry was more optimistic about the contributions likely from shale gas plays; whereas the NEB had the Arctic gas and pipeline coming into play earlier than industry. The pace of Canadian shale gas development will be set by the netbacks determined by the export demand from US and Asia. Approval has been granted to build a 1.4 Bcfd LNG export facility in Kitimat, British Columbia, to take advantage of premium natural gas prices in Asia.

Figure 31: Source – NPC North America Study Database

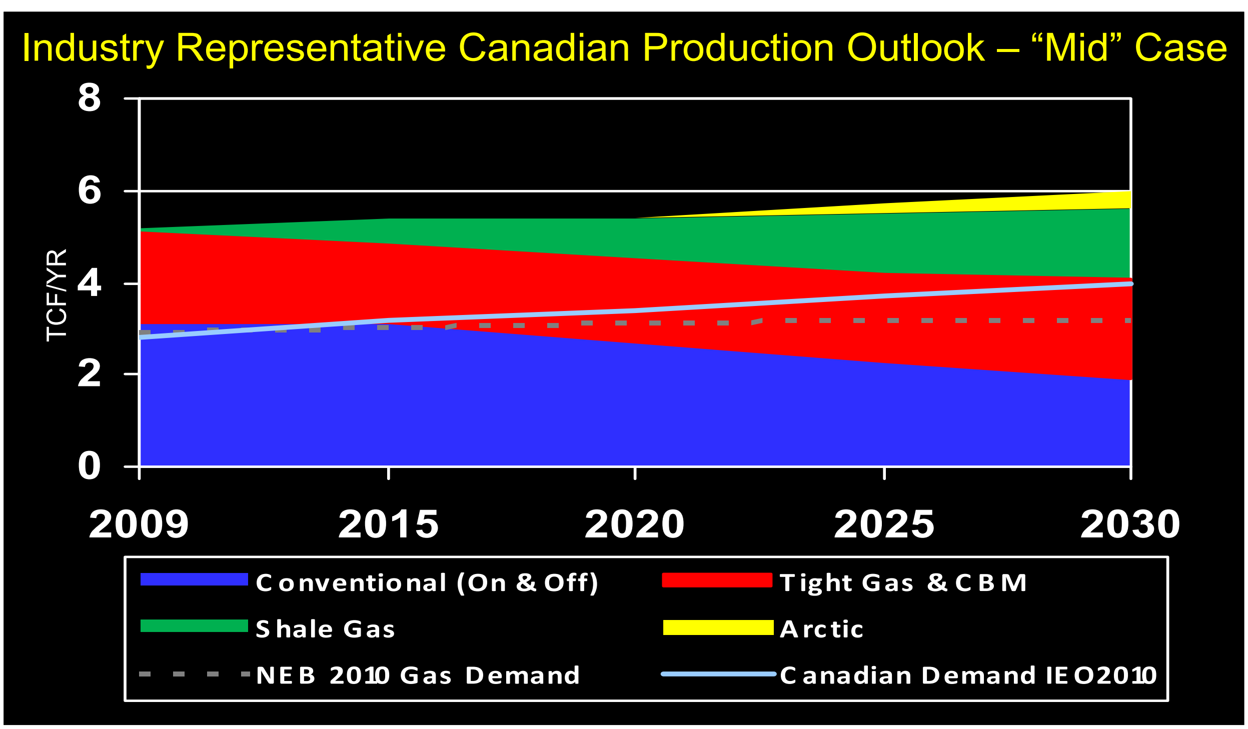
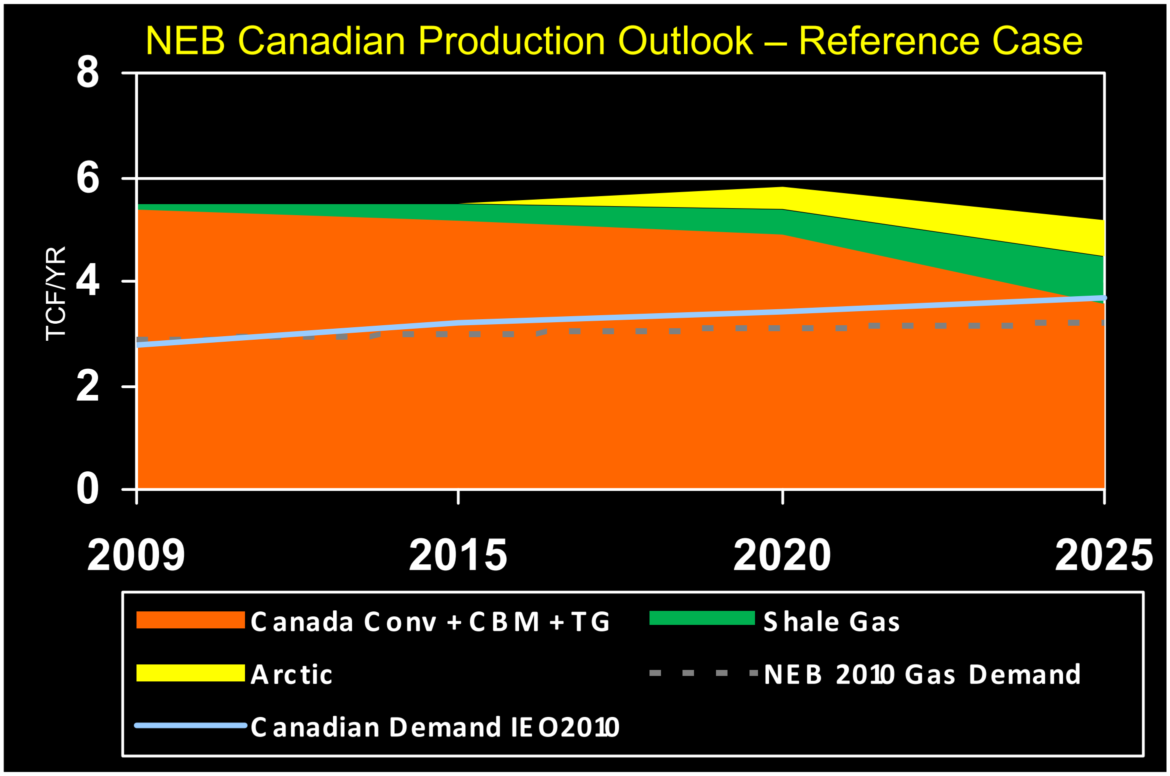


Figure 32: Source – Canadian National Energy Board



Only in the most optimistic, high-side cases was the ***United States conventional*** production levels forecasted to increase above the current 10+ TCF/YR. As in Western Canada, the lower 48 onshore conventional reservoirs and fields are mature and declines rates are steep. As can be seen in figure(s) 34 from the 2003 NPC Gas study, the base decline rates and average productive capacity of new wells continues to decline in this category. The number of new conventional gas wells required to simply maintain production levels continues to increase over time, as initial rates per well become smaller, and industry has been focusing its capital in lower cost and/or higher productivity wells in other categories (e.g. unconventional and offshore supply regions) to reduce their finding and development costs. Recent exploration discovery sizes have been small, wildcat success rates have been low, and a lot of the remaining resource potential is within the small field fractions in the ***US L48 onshore conventional sector***.

Figure 33: Source – NPC North America Study Database

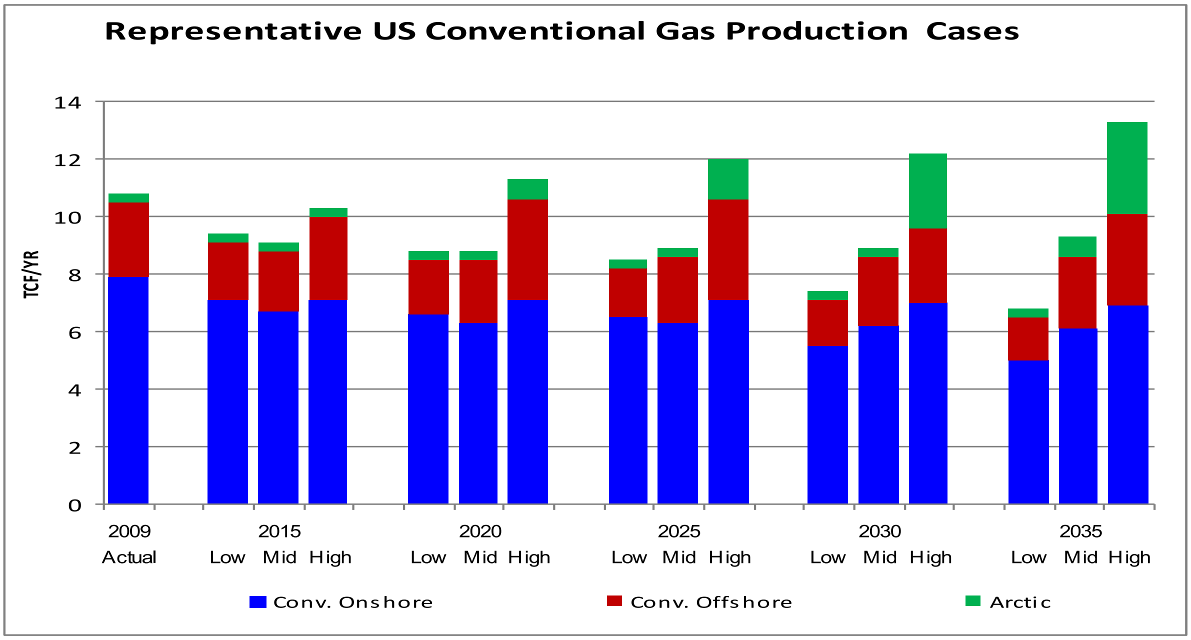


Figure 34: Source – 2003 NPC North America Gas Study

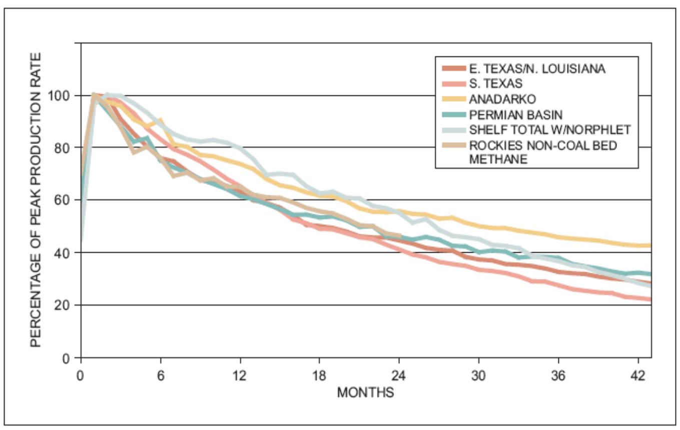


Figure S4-24. Comparative Well Profiles (1990 Vintage)

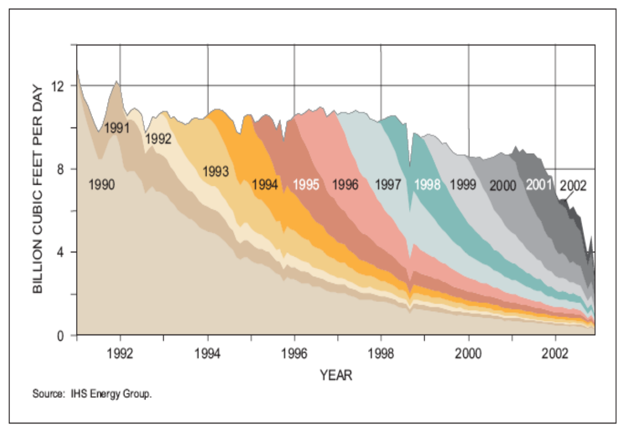


Figure S4-56. Gulf of Mexico Shelf – Daily Wet Gas Production from Gas Wells, by Year of Production Start

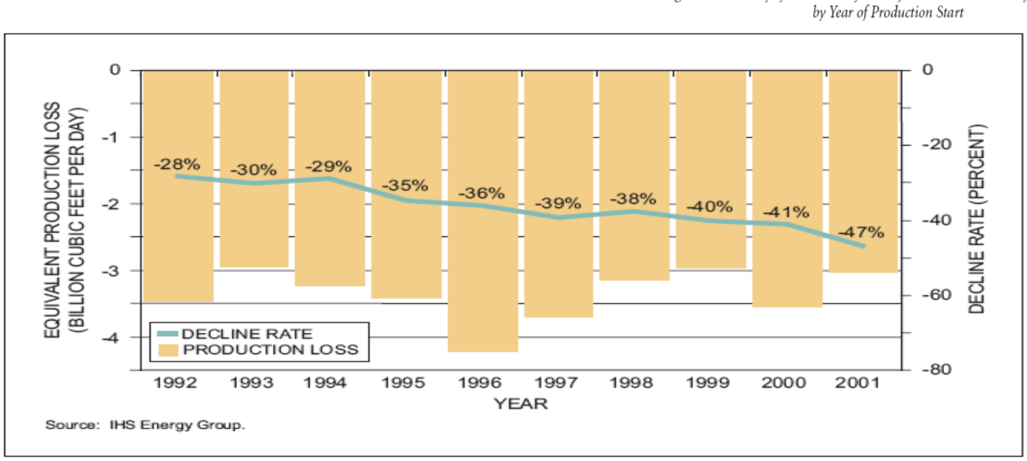


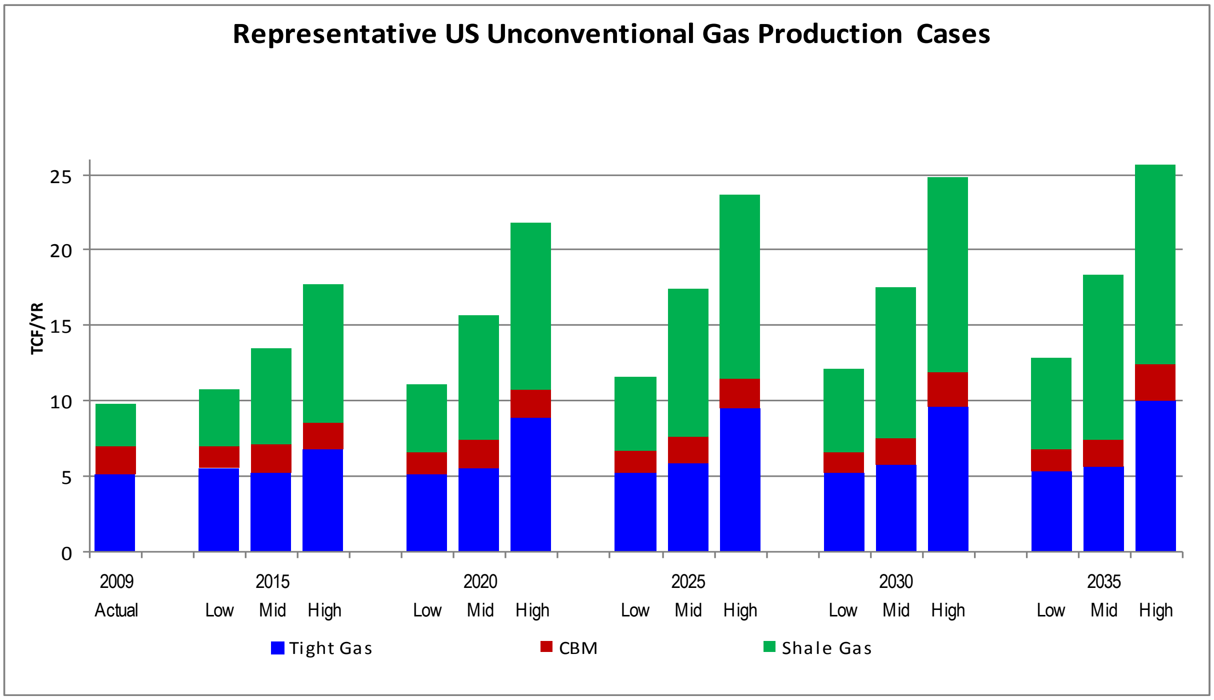
Figure S4-57. Gulf of Mexico Base Shelf – Decline Rate of Base Gas Production if No New Wells had been Drilled, and Equivalent Production Loss

There was a large range in the estimates for future productive capacity of the ***L48 offshore***, with current production levels of around 2.5 TCF/YR falling to 1.5 TCF/YR in 2035 in the low-side cases and as high as 3.2 TCF in the high-side cases. While the flow rates from excellent offshore wells can exceed 50 MMCFPD (initial flow rates), these wells have steep decline rates and thus active drilling programs to replenish supplies is needed to maintain and grow production. We interpret the decline in US L48 offshore production levels in the cases we collected from industry to reflect concerns about the resumption of historic drilling activity levels in the Gulf of Mexico and the timing of access to new areas in the Gulf, Pacific and Atlantic.

The ***Arctic (Alaska)*** region currently is producing less than 0.3 TCF/YR; however there is considerable discovered (in excess of 35+ TCF) reserves and additional undiscovered resources that could supply in excess of 2+ TCF/YR if the necessary infrastructure was in place to move gas into the US L48 markets. As with the Mackenzie project in the Canadian Arctic, the timing of the Alaska pipeline project continues to slip and most forecasts now question whether these supplies will be entering the market before 2035, which is a major deviation from past NPC studies where industry had the Arctic gas on-line as early as this decade. Arctic gas reserves and resources are not competitive with other NA gas alternative gas supplies because of several issues, including: 1) the project economics – will the long term price of gas cover the significant transportation and shipping cost ?; 2) who will bear the cost of the 25+ billion dollars to build the pipeline ?; what is the likelihood of state and federal fiscal stability over the life of project ?; 4) what are the permitting and environmental regulatory framework considerations likely to be? While the Alaska Natural Gas Transportation Projects Office (created by Congress in 2004 under the Alaska Natural Gas Pipeline Act) has stated at the Alaska Oceans and Islands Center in November of 2010 that permitting isn't a big problem and agencies have to complete environmental impact statements 18 months ahead of the project are encouraging, the time required to work through any regulatory issues that might arise could be significant.

By the next decade, it is predicted that more than 60% of the total US gas supplies are likely to come from the domestic, unconventional resource base! The smallest unconventional resource contributor will be ***coal bed methane***, with current production levels around 2 TCF/YR and future production capacity ranging from 1.5 – 2.5 TCF/YR by 2035 based on various forecasts collected in this study. Three quarters of the current production is from the Rocky Mountains, with the lion's share from the San Juan and Powder River Basins. The majority of regional data for the coal bed methane sector suggested the approximately 0.5 TCF/YR of production from the Gulf Coast, East Coast and Mid-continent regions will likely be difficult to sustain till 2035. The vast majority of the remaining resource potential is situated in the Rockies. The San Juan and Powder River Basins have been producing for more than twenty five years and the low-hanging fruit has been exploited. CBM developments are not without above ground challenges, including the disposal of water separated from the producing wells, the impact on surface landowners and local communities. Fortunately, these issues can be monitored and have been managed to minimize their impact. Industry and the government agencies are also continuing to evaluate new technologies and approaches to protect the environment and maximize operational best practices.

Figure 35: Source – NPC North America Study Database



Tight gas reservoirs are currently producing around 6+ TCF/YR and almost all the forecasts indicated that supplies can grow from this sector. Although most of the lowest cost, tight gas "sweet spots" have been developed by industry, there are still considerable field infill and additional exploratory opportunities at supply costs of $5 -10 per MCF that can be pursued by industry and relatively easily tied into the existing regional infrastructure. In 2008, the Rockies and Gulf Coast each produced around 2 TCF/YR, while the Mid-continent contributed around 1 TCF/YR. Most outlooks anticipate that the Gulf Coast tight gas production will decline in the future but there will be possible increases by 2035 from the Rockies region. Operators have been actively developing tight gas fields for over 10-15 years and working with the government (state and federal) agencies and local communities to address issues that arise. The areas of concern include continued increased environmental protection, with water use and management being the most pressing issue from the energy industries, public and government's perspective.

US and Canadian tight and ***shale gas*** are believed to comprise more than 60% of the remaining total resource base and will be major contributor of gas production growth and energy self sufficiency and security objectives in the future. US shale gas production has grown from about 1 TCF/YR in 2006 to currently in excess of 4 TCF/YR. Continued shale gas exploration and development over the next 5 -10 years will help further reduce the current uncertainty and tighten the range for the US and Canadian resource base ("size of the prize"). While conventional, CBM and tight gas developments are becoming increasingly costly and/or complex, "lower" cost shale (marginal cost of US supply as measured by full cycle F&D costs) developments provide the potential to grow US and Canadian production. If the higher-end recoverable resource estimates are affirmed, a robust production plateau can be maintained for many decades. In the mid and high industry cases in the figure above, shale gas production is anticipated to grow to over 10+ TCF/YR by 2035. The main challenge associated with large scale shale gas developments are potential concerns about water use and management associated with the hydraulic fracturing applications required to produce commercial quantities of gas from shale reservoirs.

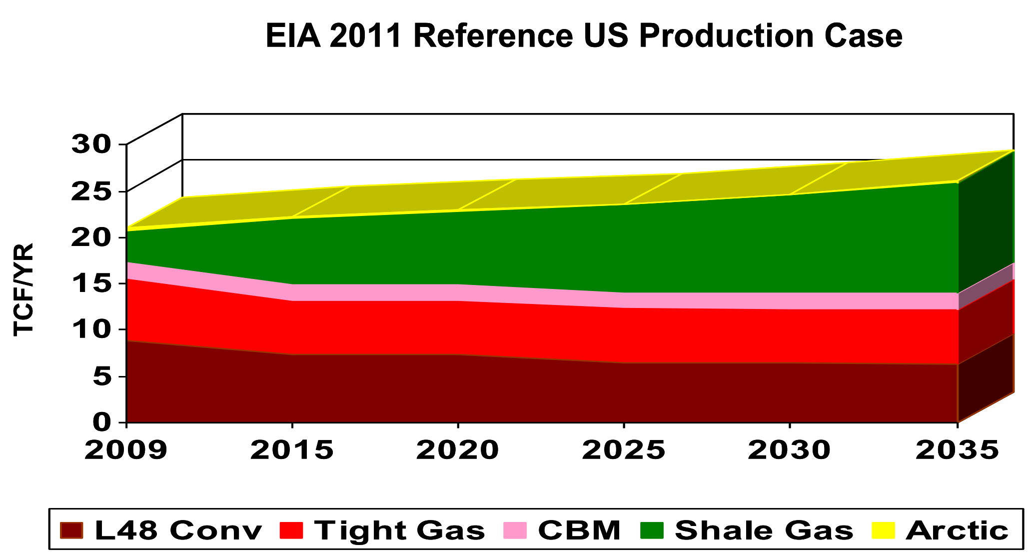
While all shale gas does not have a supply cost below $5/MBTU (assuming a continuation of the current regulatory and business environment), we anticipate industry will continue to focus on North America gas investments in this sector. A significant concern right now for industry is the relatively low US gas price realization relative to oil, which is trading at a multiple of around 4X for an energy equivalent unit of gas. This low gas price causes some operators to direct more of their North American investments into liquid rich shale plays. International gas prices currently are more "coupled" with crude price, and, thus LNG exports are being directed to these markets.

In the EIA and IEA integrated energy outlooks in Figures 36 and 37, the supply volumes have been determined based on the results of the projected, future, demand forecast requirements. Likewise, most industry and public cases collected in this study also arrived at production level estimates in response to anticipated consumption needs based on macroeconomic and energy intensity and efficiency assumptions. In addition to demand growth projections for the various energy sources that compromise the total required energy, assumptions about the mix of gas, oil, coal and renewables in the transportation and power sector can have a measurable impact on the use and need between gas, coal and oil.

The EIA and IEA supply outlooks were developed using modeling tools that selected the most cost effective mix of domestic supplies and imports to meet the overall gas and energy demand requirements within some underlying cost of supply or product price assumptions. Basically the model uses a succession of increasing volumes and supply costs assuming the lowest cost resources are depleted first before using the next highest supply cost. The EIA 2011 reference case assumes current laws and regulations, technologies that are commercial or reasonably expected to become commercial over next decade and adds a premium to the capital cost of CO2-intensive technologies to reflect market behavior regarding possible CO2 regulation. The IEA future policies case, the New Policies Scenario — "takes account of the broad policy commitments and plans that have been announced by countries around the world, including the national pledges to reduce greenhouse gas emissions and plans to phase out fossil-energy subsidies even where the measures to implement these commitments have yet to be identified or announced. These commitments are assumed to be implemented in a relatively cautious manner, reflecting their non-binding character and, in many cases, the uncertainty shrouding how they are to be put into effect". As a result of the aggregation process for the industry cases, it is difficult to understand all the underlying assumptions for the case below, however it is likely to represent a business as usual scenario". **A full cycle model that also accounts for the total environmental and economic impacts for any outlook or projection would be helpful in understanding all the implications of the complex energy system and provide more context and assessment of future energy policy options.**

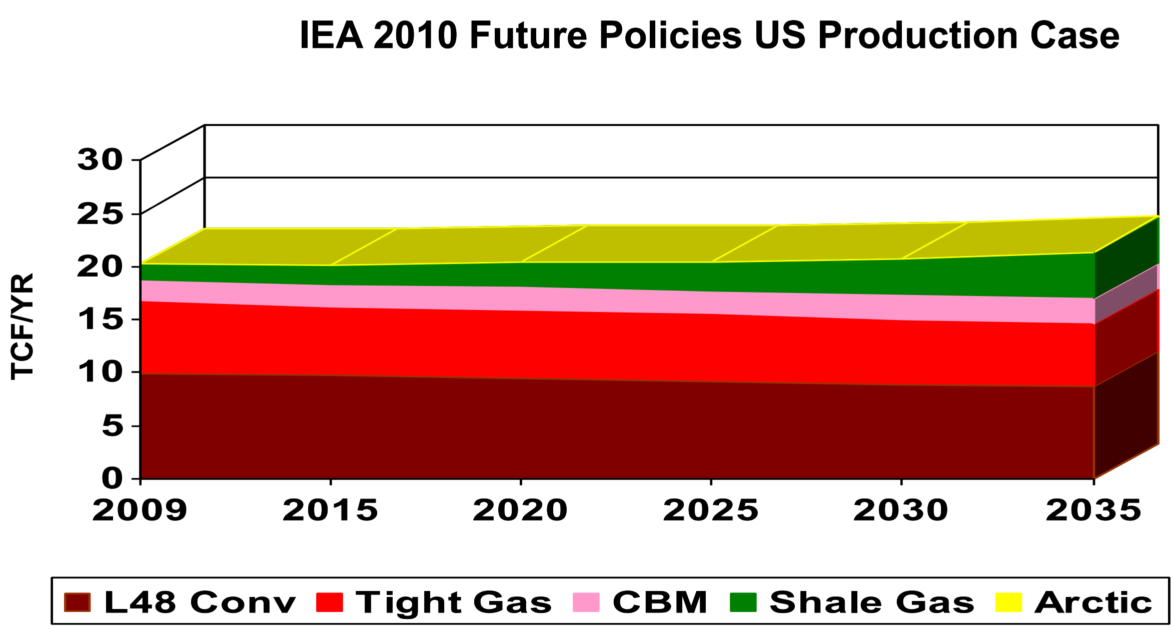
The EIA 2011 Reference case (figure 36) suggests that the production is likely to decline for the combined L48 conventional, tight gas and CBM areas over the study timeframe, which is probably a function of both the size of the prize and supply cost factors. The EIA models utilize the lowest cost (price) resources to fill the anticipated future demand requirements. The EIA significantly enhanced its shale gas production outlook in the 2011 reference case as compared to 2010, which reflects the increased resource base from 347 to 827 TCF this past year and its perceived relative lower cost of supply compared to other conventional and unconventional supply sources. This also resulted in the EIA reducing its forecast of the US wellhead and Henry Hub prices by $2 per MBTU (2009 dollars) from the 2009 AEO to 2011 AEO outlooks. Note these price projections don't account for cost escalations from increased regulatory requirements or possibly for the industry services, materials and/or equipment; or alternatively, increased efficiency or cost reductions based on technology advancements, operational learning's, etc. Product prices are likely the result of supply availability and cost vs. demand requirements/timing based on consumer behaviors, plus volatility resulting from market factors and forces.

Figure 36: Source – EIA 20111 AEO



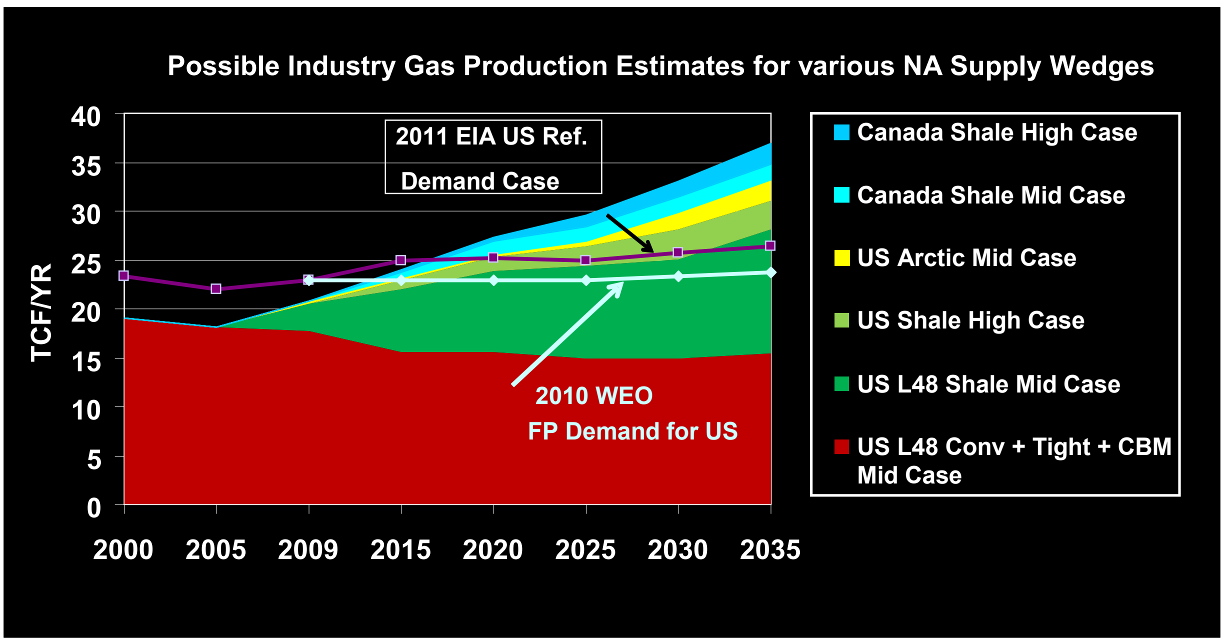
In the IEA's Future Policies (FP) case (figure 37), "global demand increases with fossil fuels accounting for over one-half of the increase in total primary energy demand. Rising fossil-fuel prices to end users, resulting from upward price pressures on international markets and increasingly onerous carbon penalties, together with policies to encourage energy savings and switching to low-carbon energy sources, help restrain demand growth". In the IEA US gas supply case, the production growth rate is the most pessimistic of three above cases, largely reflecting the reduction in both energy and gas demand in this scenario which assumes energy savings and reduced carbon emissions above and beyond the IEA 2010 current policies reference case. The IEA case does assume natural gas has more favorable environmental and practical attributes, and places constraints on how quickly low-carbon energy technologies can be deployed. The IEA Future Policies case also has significantly less contribution from shale gas than the EIA and North American industry forecasts, which may reflect dated shale gas resource and supply cost estimates.

Figure 37: Source – IEA 2010 WEO



The representative industry US illustration, figure 38, reflects the combination of a mid and high side supply case. It has been included to illustrate the potential sources and capacity from the largest North American production "wedges" to satisfy US energy demand. Two demand cases were provided for context and represent a more traditional energy mix (modest consumption cases by the EIA and IEA). High demand growth cases with potentially a step change in gas penetration in the power and transportation sector could raise demand 10 - 20 TCF/YR depending on how much the US energy policy is underpinned by gas utilization. Historically, the US has imported gas from Canada via long distance pipelines and LNG cargoes to meet the shortfall not provided by domestic gas supplies. In all the above outlooks, shale gas is believed to change this paradigm and provide future supplies to meet US and Canadian consumption needs. While the rest of the current United States gas sources (e.g. Conventional Onshore + Offshore + Tight Gas + CBM) are unlikely to meet demand over the past few years, US shale gas can fill the gap depending on how quickly industry can grow production. The mid case (dark green wedge in above chart) suggests that within 10-20 years, shale gas together with traditional areas can entirely meet modest US demand scenarios. Note we haven't included the current Canadian and LNG imports into the future projections which can provide additional volumes to meet "self-sufficiency". Additional growth in US shale gas, the Arctic gas and supported by large scale shale gas resource developments in Canada could result in significantly additions to the supply availability for US market needs.

Figure 38: Source – Industry Aggregated Data



We believe it is critical to understand the relationship between the key underlying production capacity drivers and fundamentals, rather than just relying upon a supply equation derived by backfilling demand estimates. There are a range of potential gas demand scenarios, each with unique overall gas and other energy source mix and assumptions. For example, if there is ample, cost effective US gas supplies that can be used for an increased share of both the power and transportation sector, this could result in a shift in the current energy mix. Demand needs can be met from various supply alternatives depending on the production capacity and cost.

We decided to address the question of the US and Canadian supply and production capability for the major production "wedges" or hubs by utilizing the collected data in this study and the modeling capabilities at ICF to illustrate constrained, mid and unconstrained US and Canada gas supply cases. The NPC study data and ICF modeling capabilities were utilized to increase our understanding and interpretation of the data collected and analyzed by public, government and industry organizations. Additional work can be done (including the oil sector) for a fully integrated model that can address the financial, environmental and social impacts of various scenarios and the resulting impact on economic growth, environmental protection and energy security.

The input parameters were developed based on the collective input and wisdom of a team of industry (consultant and E&P company analysts) to bracket the range of possible outcomes. Please note the low side and high side production cases have low probability of occurrence, but likely more in the 10% rather than 1% for extreme, outlier cases. Attached below is a thematic summary of the key parameters used to build the supply capacity cases:

Figure 39: Source – NPC North Oil/Gas Study & ANGA Data

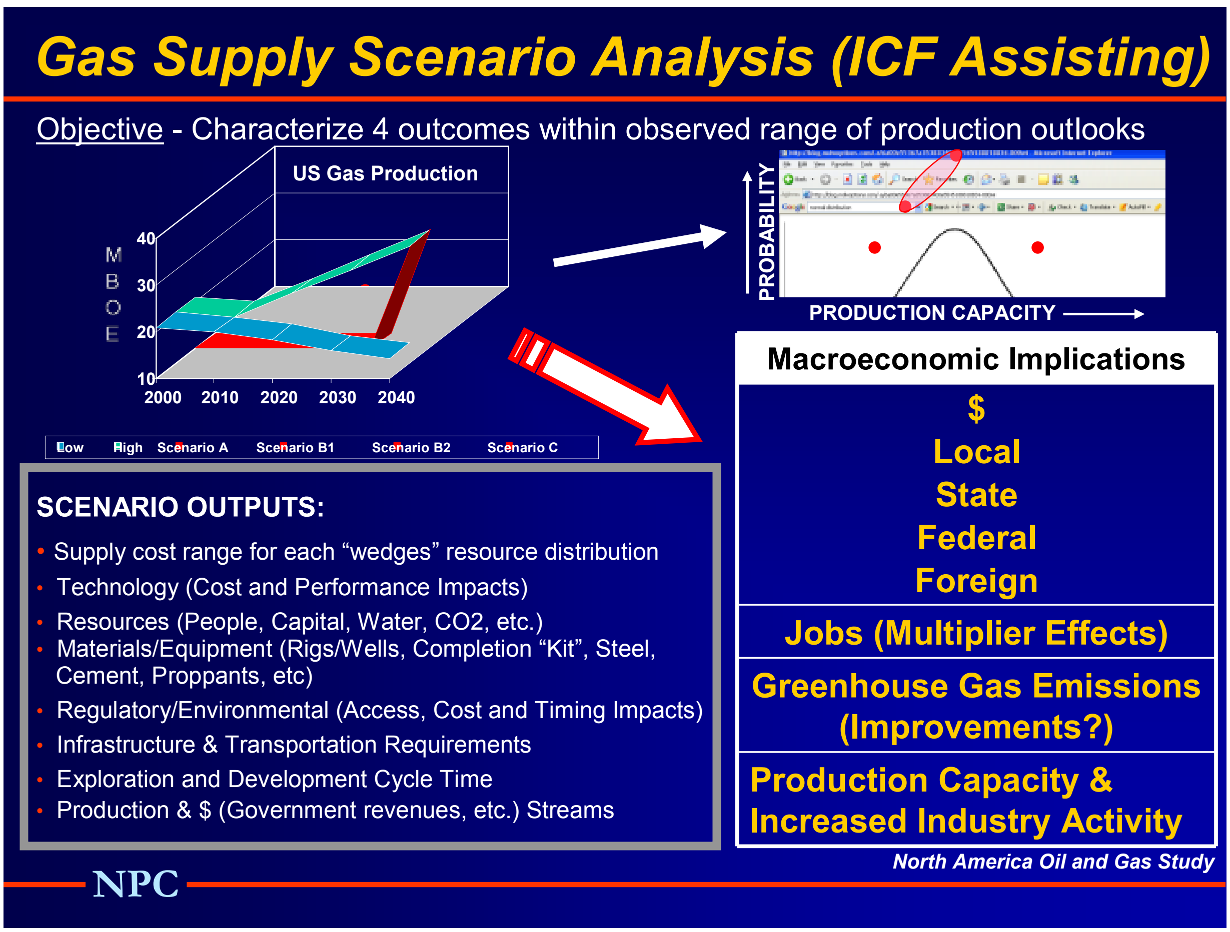
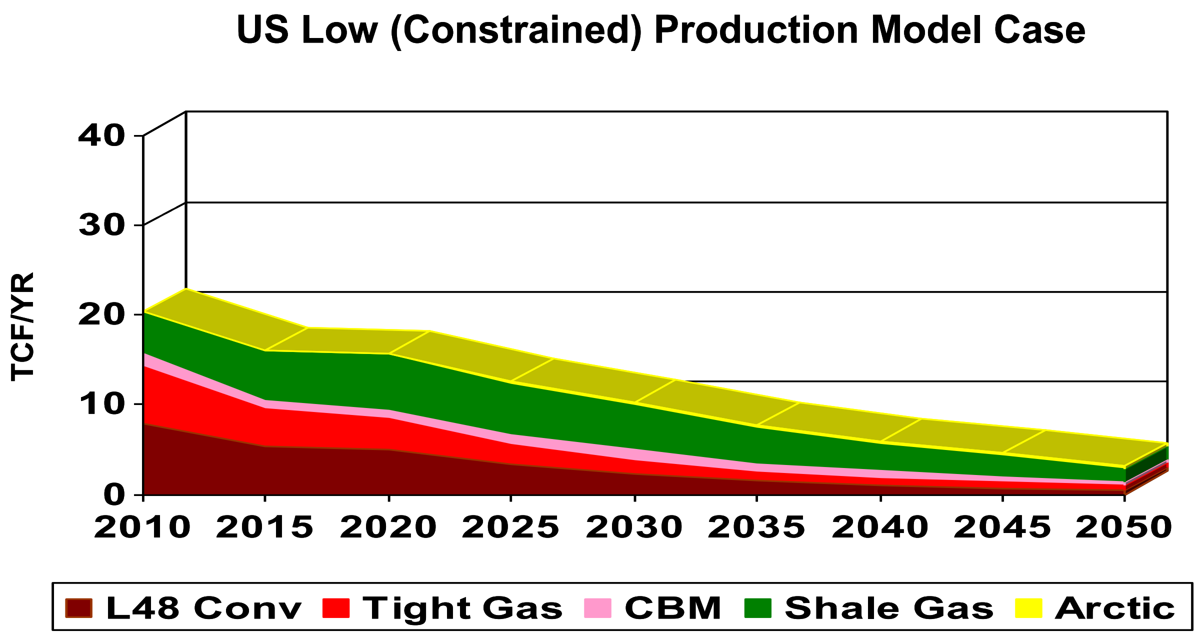


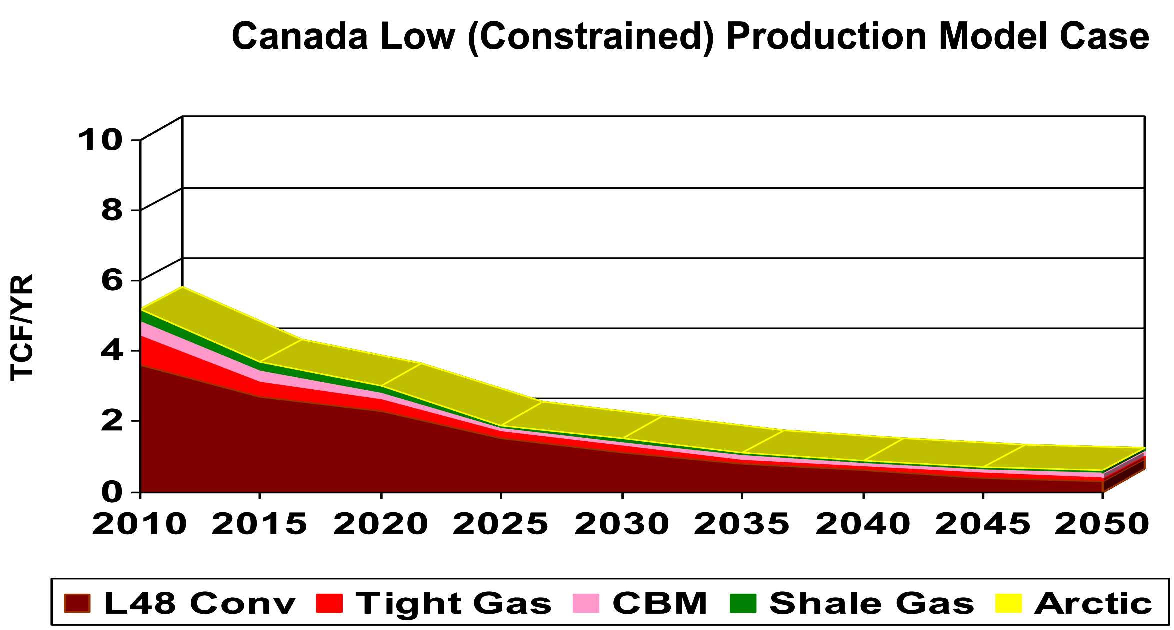
Figure 40: Source – NPC North Oil/Gas Study & ANGA Data

	LOW TEST CASE	MIDDLE TEST CASE	HIGH TEST CASE
Resource Base Assumptions	Low resource	Middle resource	High resource
Environmental Regulations	More stringent environmental regulations	Current environmental regulations	Optimized (risk-based) environmental regulations
Land Access Policies	More restrictive access	Current access policies	Optimized (risk-based) access regulations
Lower Cost Technologies	Current D&C costs	Current D&C costs	Slow reductions in D&C costs
Higher Success Rates and EURs from technology	No performance improvements	Slow performance improvements	Faster performance improvements
CO2 Availability for EOR	Current and planned natural source projects	Planned natural source projects plus anthropogenic capture R&D projects	US /Canadian GHG policies lead to large captured CO2 volumes by 2030
Maximum Oil Supply Cost	$50	$100 Run also @ $130	$200
Maximum Gas Supply Cost	$4.00	$6.00 Run also @ $8	$12.00

The supply buildups in figures 41-42 are based on an arbitrary demand ceiling of 45 TCF/YR for the combined US and Canadian domestic markets and assumes the lowest cost gas from both areas are drawn upon first as the total production ramps up towards the demand ceiling. The constrained production cases assume a low side resource base of 1500 TCF (700 is shale gas) in the US and 500 TCF (200 is shale gas) in Canada, restricted access to new acreage and plays, more stringent environmental regulations and a relatively low price environment ($4.00 per MBTU maximum supply cost in 2009 dollars, where industry investment and activity is likely to be curtailed). Canada can remain self sufficient throughout this decade in this case, whereas the US would require low cost LNG imports to meet the US consumption needs in light of a NA gas supply shortfall. We believe this case is unsustainable and unrealistic, since gas prices would inevitably rise in this type of scenario and the higher cost resources in North America would then come into play. This model case is useful from the standpoint of illustrating how limited resource access and restrictive policies will curtail oil and gas development, which likely will result in rising energy prices when supply can't satisfy demand needs. This case also suggests there isn't an unlimited supply of low cost shale gas.

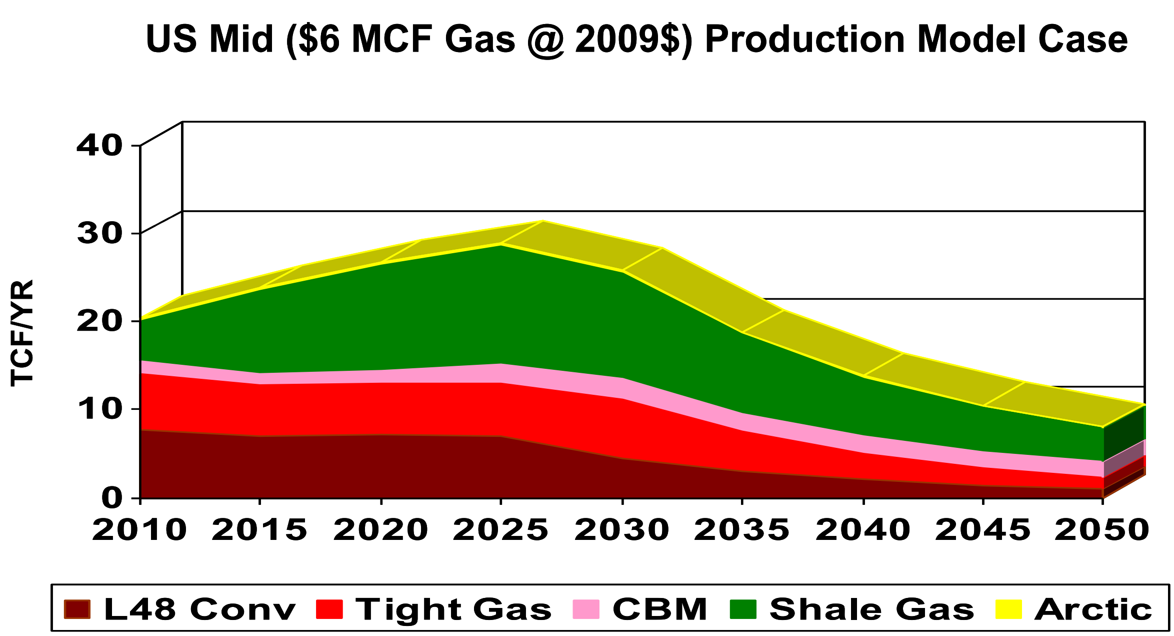
Figure 41: Source – NPC North Oil/Gas Study & ANGA Data



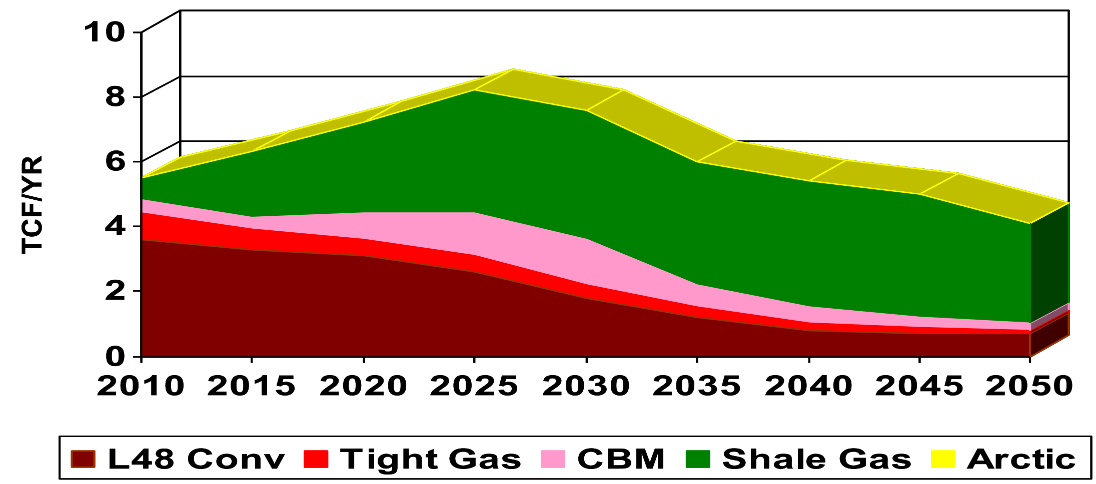


The two ($6.0 and $8 per MBTU supply cost maximums), different, mid-cases assumes a resource base of 2300 TCF (1000 TCF is shale gas) in the US and 900 TCF (400 TCF is shale gas) in Canada, current conditions for new acreage and plays access and environmental regulation, and an historical progression of improved ultimate well recoveries (EUR's) and success rates. The penetration of LNG imports and competitiveness in the North American market space is anticipated to be greater in the $8 case, providing European and Asia Pacific markets are not paying a premium or are coupled to high, global oil prices. While the production growth pace appears overly aggressive (e.g. 2020 to 30 buildup in Canada Mid $8 model case, etc.) in a few instances, these cases are useful in understanding the magnitude and sustainability of North American domestic gas supplies. In both US production "mid-cases", the domestic resource base can sustain production levels above 25 TCF/YR out to 2035 with resources at a supply cost of less than $6 and 8 per MBTU ($2009), providing costs don't significantly escalate from today's levels due to market factors (materials, equipment, services inflation) and/or new, large, regulatory and environmental regulatory expenses. In the event buyers are secured for the potential Kitimat LNG facility on Canada's west coast, in excess of 1 BCFD could be developed from Western Canada gas shale before 2020. In all of these cases below, Arctic gas from Alaska and Mackenzie projects have not been included in these projections, which could be more than 3 TCF/YR of additional supplies if and when the required pipeline infrastructure is in place. Moreover, Canadian supplies greatly exceed their internal demand and the incremental production (largely from growth in shale gas and CBM opportunities) would be routed to the US market. The ramp up of Canadian shale gas and CBM may coincide with the depletion of the lowest cost US supplies, which then access the next higher incremental cost supplies. Competitively priced LNG imports can provide a back-stop to a US energy policy which contemplates high gas demand levels, likely supplying gas for increased utilization in the power and transportation sector. All instances below are underpinned by shale gas expansion, often at a challenging pace for industry. Therefore, delays in acreage access, well permitting and completions, and construction of gathering systems and long distance transportation trunk lines can severely limit domestic production growth.

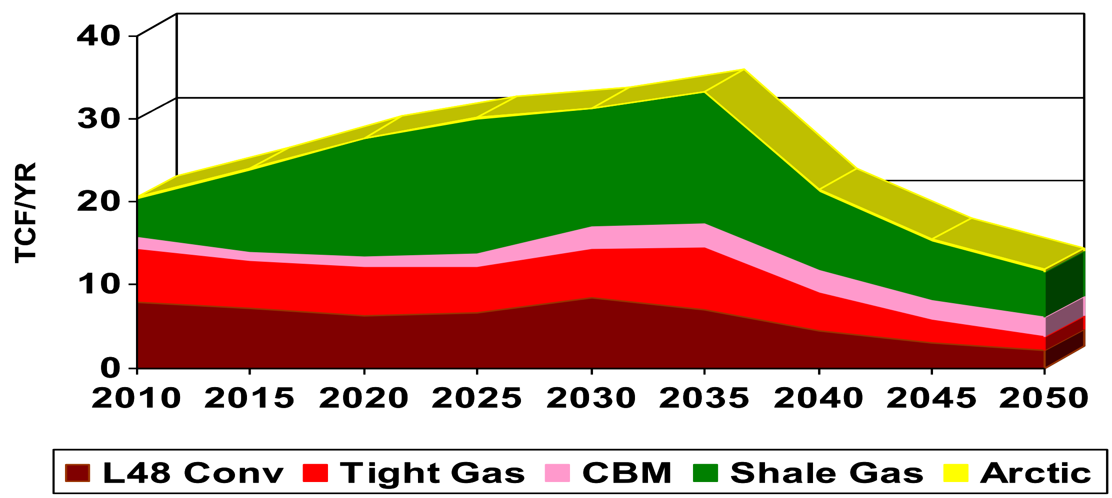
Figure 42: Source – NPC North Oil/Gas Study & ANGA Data



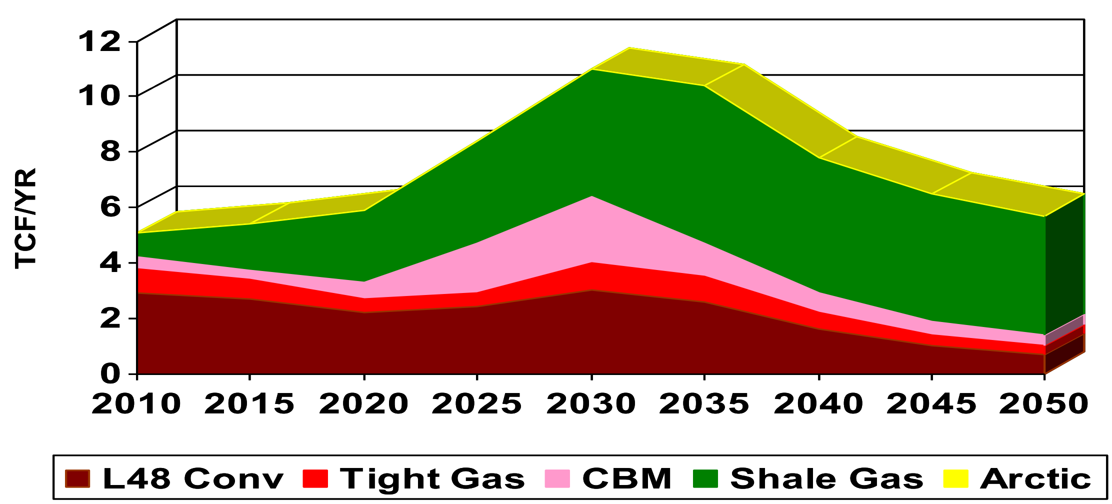
Canada Mid ($6 MCF Gas @ 2009$) Production Model Case



US Mid ($8 MCF Gas @ 2009$) Production Model Case

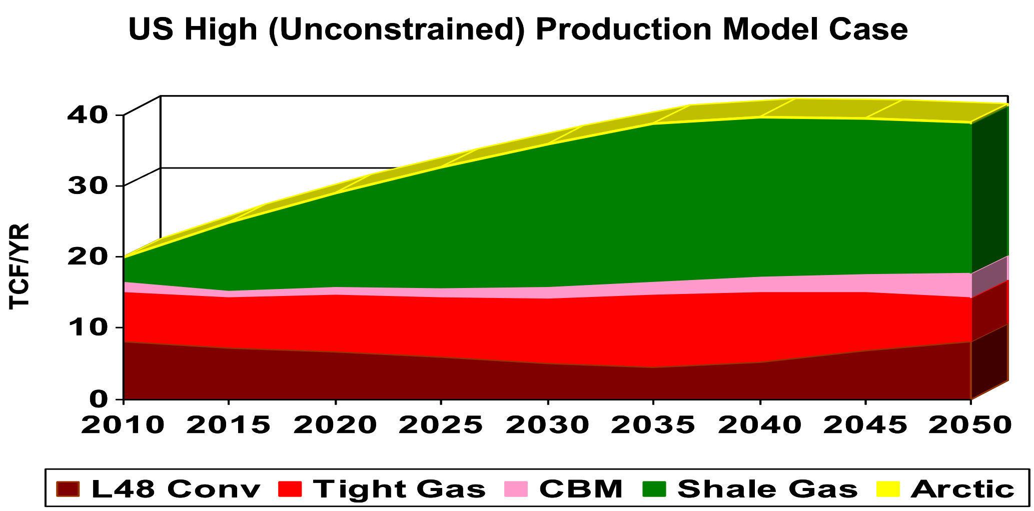


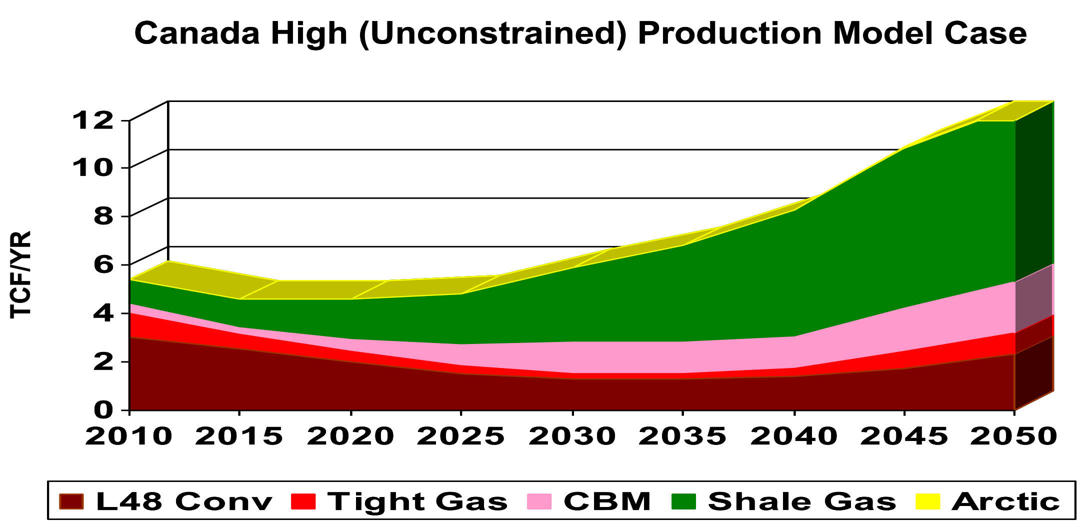
Canada Mid ($8 MCF Gas @ 2009$) Production Model Case



The unconstrained production cases below assumes a resource base of 4000 TCF (1800 TCF is shale gas) in the US and 1250 TCF (400 TCF is shale gas) in Canada, optimal access to new acreage and favorable regulatory policies which protect the environment and ensure safe, efficient operations; continued technology innovation and best practice applications to reduce costs and improve performance, and the expected increases in energy prices as more challenging and difficult resources are extracted from the gas endowment. Each of these assumptions is a good aspiration/objective for the industry, government and public to support and advocate, since it probably leads to a more reliable, secure and even affordable energy future. Economic growth and environmental protection need to optimized and include an in depth analysis of all the cost/benefits of future policy initiatives. We believe what is needed is a clearly articulated vision and line of sight for the future of the US/North America energy sector. Energy security can be enhanced by optimizing the domestic energy mix and resource development priorities, although truly sustainable energy security is a function of global energy security given the interdependences of global commodities and market.

Figure 43: Source – NPC North Oil/Gas Study & ANGA Data





These cases suggest that the **North American resource base, in an ideal business environment agreed to by industry, government and public stakeholders can MOVE THE ENERGY NEEDLE.** The continued evolution of shale gas and the pursuit of new, cost effective resource opportunities in the more mature North American resource sectors are needed to deliver sustainable results. The combination of the two unconstrained graphs below indicates that Canada can meet all its domestic consumption needs while also providing additional supplies into the US when these Canadian resources can financially compete with US domestic alternatives. In the next two decades, the US shale gas opportunities appear to be the lowest (marginal) cost of supply and will be developed preferentially ahead of the conventional, tight gas and CBM sectors on a finding, developing and operating cost basis. As the marginal US shale gas resources are finally developed, Canadian shale gas (more remote from US markets) and Canadian CBM production should start to increase, followed by a pursuit of some of new, higher supply cost conventional opportunities in new offshore and Arctic provinces in both the US and Canada and finally by new technology and long term opportunities (e.g. hydrates). Exploration, research and technology development should be encouraged for all gas sources (and all energy sources as championed in the 2007 NPC Hard Truths Study), since we need to progress and mature all possible solutions for our growing needs for energy.

Expansion of the role of gas in the US, North America and even the world's hydrocarbon and energy future can provide economic benefits and a reduction in the overall US energy environmental impacts, while also clearly aiding in the energy security realm. As detailed in the findings of the NPC Global Hard Truth study, the US appears to have consumed more of the total oil endowment than gas. Coal is abundant, but this large resource base is relatively restricted to a few locations around the world (e.g. Australia, China, India, Russia and the US). While a more detailed, fully integrated modeling and interpretation effort is required for a comprehensive cost and benefit analysis in the use of various energy sources and the resultant impacts on the economy, environment, social welfare and well being of the global community, we have tried to evaluate the impact of different levels of gas production and utilization in the US and Canadian on some of these above factors. However, more work is needed on all energy sources (oil, biofuels, coal, nuclear, solar, wind, geothermal, etc) and we believe this would be beneficial in advancing policy decisions that impact a broad and diverse group of stakeholders.

Domestic gas production growth could have a positive impact on the US and Canadian economies. The production growth in the mid and high side model cases could results in an increase in employment of 2 to 3 fold, government revenues up to 9 fold, and capital investment levels 3 times the current levels for the gas sector. There are also potentially other macroeconomic impacts since increased utilization of US and Canadian domestic resources will also impact foreign trade balance and other interdependencies between the energy and other sectors in the economy. However, increased water use (from 20 to 100 million gallons of water for hydraulic fracturing) and CO2 emissions (180 to 300 million tons) will result from the high side production cases. Environmental protection is a priority because increased activity in this sector will result in larger surface footprints, water usage and greenhouse gas emissions. However, a complete energy system balance needs to be calculated for all energy sources and their impacts on the environment. Although significant increases in gas production will have an increased environmental impact, overall it may be less than the entire North American energy system if gas substitutes for oil and coal?

GAS PRODUCTION SECTOR ONLY! !

Figure 44: Source – NPC North Oil/Gas Study & ANGA Data

Direct/Indirect/Induced Jobs (1000's)	Impact	2009	2020	2030	2040	2050
Low (Constrained) Case		500	300	150	50	<50
Mid ("6") Case		500	1000	500	200	200
Mid ("8") Case		500	1100	1200	400	300
High (Unconstrained) Case		500	1100	1500	1700	1700

Government Revenues ($ Billions)	Impact	2009	2020	2030	2040	2050
Low (Constrained) Case		12	12	7	2	1
Mid ("6") Case		12	30	33	16	6
Mid ("8") Case		12	33	53	40	19
High (Unconstrained) Case		12	40	73	86	90

Capital Investment ($ Billions)	Impact	2009	2020	2030	2040	2050
Low (Constrained) Case		40	15	6	3	2
Mid ("6") Case		40	70	29	12	11
Mid ("8") Case		40	77	85	16	14
High (Unconstrained) Case		40	76	109	124	129

CO2 Emissions (Millions of tons)	Impact	2009	2020	2030	2040	2050
Low (Constrained) Case		180	160	90	60	50
Mid ("6") Case		180	200	190	130	100
Mid ("8") Case		180	200	220	180	130
High (Unconstrained) Case		180	210	240	280	290

Water for Hydraulic Fracturing (Millions gallons)	Impact	2009	2020	2030	2040	2050
Low (Constrained) Case		25	11	4	0	0
Mid ("6") Case		25	50	22	3	0
Mid ("8") Case		25	61	36	5	0
High (Unconstrained) Case		25	63	82	70	42

The production graphs and tables (figures 41-44) for the modeled cases also clearly illustrates also the long term nature and enormous scale of the energy industry and system, and, therefore the significant lead times required for project development to generate reserves and production. Foresight and planning are key, since short term decisions can have a profound effect on the long term direction and pace of producing energy. While the gas base resource is large, there are material, challenges for delivering domestic gas production growth and a long term approach and mindset is needed to address the energy trade-offs we are facing for the optimal solution for our energy future. Below is a discussion of these challenges at various stages along the gas development chain:

Figure 45: Source – Charlie Sheppard Illustration

Identification of technically viable energy resources

↓

Assessment of resource base size and commercial viability/do-ability

↓

Resource (opportunity, acreage, etc.) access

↓

Exploration (validate; quantify; decision point to trigger large development investments)

↓

Project Development (industry capacity – *people, materials, equipment, etc*; capital availability; project management practices; permitting)

↓

Infrastructure/Transportation to End Users (availability; timing of new transportation routes/networks)

↓

Production Operations (Best practices)

Resource Access – is essential to sustaining and growing North American production. Since most of the unconventional gas plays are on private rather than government held acreage, this hasn't been a big concern to date. However, many conventional offshore opportunities in the L48 and Alaska are currently not available to industry and the recent lease sales in the Gulf of Mexico have been delayed and the lease "expiry" clock is winding down on currently held acreage. Consultant studies done on the behalf of the various US government agencies have estimated that in excess of 30-50+ billion barrels and 100 – 300+ TCF are currently in moratoria areas which are inaccessible to industry.

Opportunity Identification/Research & Technology Development – is the enabler to unlock future opportunities. Industry will typically focus its resources (people, funding) in the areas it believes will have the most impact. Thus, greater dialog between industry, government and academic institutions on where the limited R&D dollars are focused may optimize the impact and results from the research and technology development efforts. Moreover, greater data collection and access in the very early stages of opportunity identification and evaluation can help accelerate cycle time. For example, although the Atlantic, Pacific and some of Arctic offshore is currently inaccessible, the collection of modern seismic in these areas would help improve our understanding of the resource potential and the commercial viability of these areas, which can only help lessen the time between opening up these areas and the production of oil and gas.

E&P Project Planning and Execution – permitting and compliance with all regulatory requirements is becoming increasingly difficult and time consuming. In the offshore sector, industry is actively seeking to begin operating again in the Gulf of Mexico deepwater and pursue exploratory activities on leases in the Arctic; however significant delays are being encountered which will likely delay future production volumes. However, it is clearly understood this issue is directly linked to operational performance, and poor execution and practices can and have deterred energy development progress. A timely solution is needed and any collaboration between government officials, industry and the public that can accelerate resolution would be welcomed. Moreover, there is a spectrum and diversity of operational and safety performance in the industry, and those who perform well shouldn't be penalized for the problems and issues created by the poor performers.

Since an increasing share of future production will be from shale and tight gas plays that require hydraulic fracturing, all permitting, operational and regulatory concerns regarding unconventional gas and oil, needs to be addressed quickly to enable production to grow from this large resource base. Water management is an area which enables exploratory and development activities to flourish Some companies have developed a process to treat formation water for use in fracturing operations. In addition to providing a clear, timely process to drill and complete wells, industry and other stakeholders should continue to explore innovative ways to reduce water use and improve recycling and disposal technology and practices. Additional environmental areas are being studied both by industry and government agencies, however we need to apply the most cost effective solutions and achieve balance between economic, environment and energy security considerations. Cost escalation in regulatory initiatives can ultimately lead to higher energy prices for consumers.

Industry Capacity – needs to be evaluated on a total energy system basis, since increases in any one sector or area may only result in a shift in resources rather than a step chain in the ability to increase total energy supplies to meet consumer needs.

As originally noted in the 2007 NPC Global Energy Hard Truths report, the petroleum industry is facing a considerable human resource challenge. A large percentage (nearly 50%) of the workforce will be eligible for retirement in the next ten years and less university graduates have entered the workforce in the past generation. Industry and the government have a role to play in helping rebuild the science and engineering capabilities and communicating the benefits of employment with oil and gas companies. An increased focus on training younger employees is essential, especially if activity levels continue to increase. Emphasis needs to be placed on operational best practices, safety and environmental protection while addressing the retirements of the highly experienced industry personnel.

While growth in the gas sector can be partially offset by shifting resources from other parts of the petroleum industry, the system could become stretched or incapable of meeting a high growth scenario in the unconventional gas and tight oil areas, Canadian oil sands, expansion of E&P in the offshore and Arctic and finally resource intensive plays like the oil (kerogen) shale play in the Rockies would suffer setbacks. Doing all things simultaneously would be a large strain on people, materials and equipment. The total United States and Canada gas rig utilization for the four "model" cases is listed in figure 46. Please note that the rig type and mix is not included in this table, and not all of the existing fleet of rigs is capable of the horizontal drilling and hydraulic fracturing completions required for new shale and tight gas wells. The increase in drilling requirements in the higher production cases will likely be met with new build rigs that can optimize the drilling efficiency of large shale and tight gas projects. The industry and service sector participants in our data interpretations workshops believed the below increased gas sector rig utilization below is feasible and achievable.

Figure 46: Source – NPC North Oil/Gas Study & ANGA Data

US RIG UTILIZATION FOR "MODEL" CASES				
	2009	**2015**	**2020**	**2025**
Low (Constrained) Case	**950**	**700**	**350**	**100**
Mid ("6") Case	**950**	**1150**	**1250**	**1150**
Mid ("8") Case	**950**	**1050**	**1350**	**1400**
High (Unconstrained) Case	**950**	**1200**	**1350**	**1450**

Canada US RIG UTILIZATION FOR "MODEL" CASES

	2009	2015	2020	2025
Low (Constrained) Case	**250**	**125**	**10**	**10**
Mid ("6") Case	**250**	**200**	**200**	**225**
Mid ("8") Case	**250**	**125**	**175**	**275**
High (Unconstrained) Case	**250**	**125**	**125**	**125**

Infrastructure Supply Chain – in many of the outlooks we received, infrastructure capacity and capabilities weren't considered, or they assumed that if development projects go forward, the transportation infrastructure would be in place to evacuate these hydrocarbons. The pace of project development and infrastructure requirements is often underestimated and project delays are common (e.g. Alaska and Mackenzie Arctic gas pipelines, proposed Keystone pipeline to move Canadian oil sands production to the US Gulf Coast refineries, etc.). In addition to large trunk lines, the development of subsidiary gathering systems to move unconventional gas and oil into major trunk lines can also be challenging and time consuming. Moreover, a dramatic increase in the processing and utilization rate (potentially up to 1 million barrels a day) in Natural Gas Liquids (NGL) that might arise as the result of liquid rich shale gas production could also create bottlenecks and the need for new gas processing facilities.

Industry/Government/Public Cooperation – can be the linchpin to work through any obstacles and challenges to our energy future. We believe the most rapid and effective way to resolve issues is to work together to understand the fundamentals, quantify the benefits and concerns, openly discuss the trade-offs with all the concerned stakeholders; and then jointly support and proceed with a "solution" to accelerate energy "gains" (increased efficiency and reduction in energy use, increased supply, increased environmental protection and increased energy security).

One possible mechanism to improve knowledge of the energy fundamentals is to utilize the current organizations (e.g. National Petroleum Council) to facilitate governments, industry and public in collecting, discussing and sharing data that would be maintained in some data repository. Improving the full cycle, energy value chain modeling (tools, data, interpretation, discussion and workshops) could aid in a more fulsome discussion of various energy visions, strategic direction and overall energy policy options. While periodic studies by the industry, government committees, and public institutions are both helpful and useful, they often quickly become outdated because the data is not refreshed and the study participants disperse with little continuity to enable implementation of the recommendations. This can result in repeatedly revisiting the same issues with minimal follow through and buy-in on recommendations. There are several models that could be pursued to improve the collective knowledge, strengths and wisdom of the energy "community" if there is support to consider new paradigms and we welcome the opportunity to discuss with interested parties.

VI. Oil/Liquids Resource and Production History

Total global oil endowment is estimated to be in excess of 5 trillion barrels. As can be observed from figure 47, the global oil endowment is concentrated in a few regions around the world. Liquids demand exceeds domestic production in many nations. Global and US consumption depends on reliable supplies freely traded among nations. A recent media commentator noted *the last eight US administrations have all sought to eliminate the dependence on foreign crude and considered various alternative energy sources in addition to fossil fuels. Yet, while the United States was able to put a man on the moon within ten years of President Kennedy's goal, we have been unable to become energy self sufficient.* While the United States has been blessed with large natural resources (second largest gas and coal producer in the world, and the third largest oil producer), being self sufficient for liquid hydrocarbons is a very ambitious and probably unattainable goal, especially over the next 40 years. "**Ideally, rather than strictly focusing on the pursuit of energy self sufficiency, nations/global consumers should strive to moderate demand, expand and diversify domestic energy supplies and strengthen global energy trade and investment. It is becoming increasingly difficult for any nation to become disengaged from global energy activity, trade and finance" (2007 NPC Global Energy Hard Truths Study).**

Figure 47: Source – NPC Global Oil/Gas Study (2006-07)

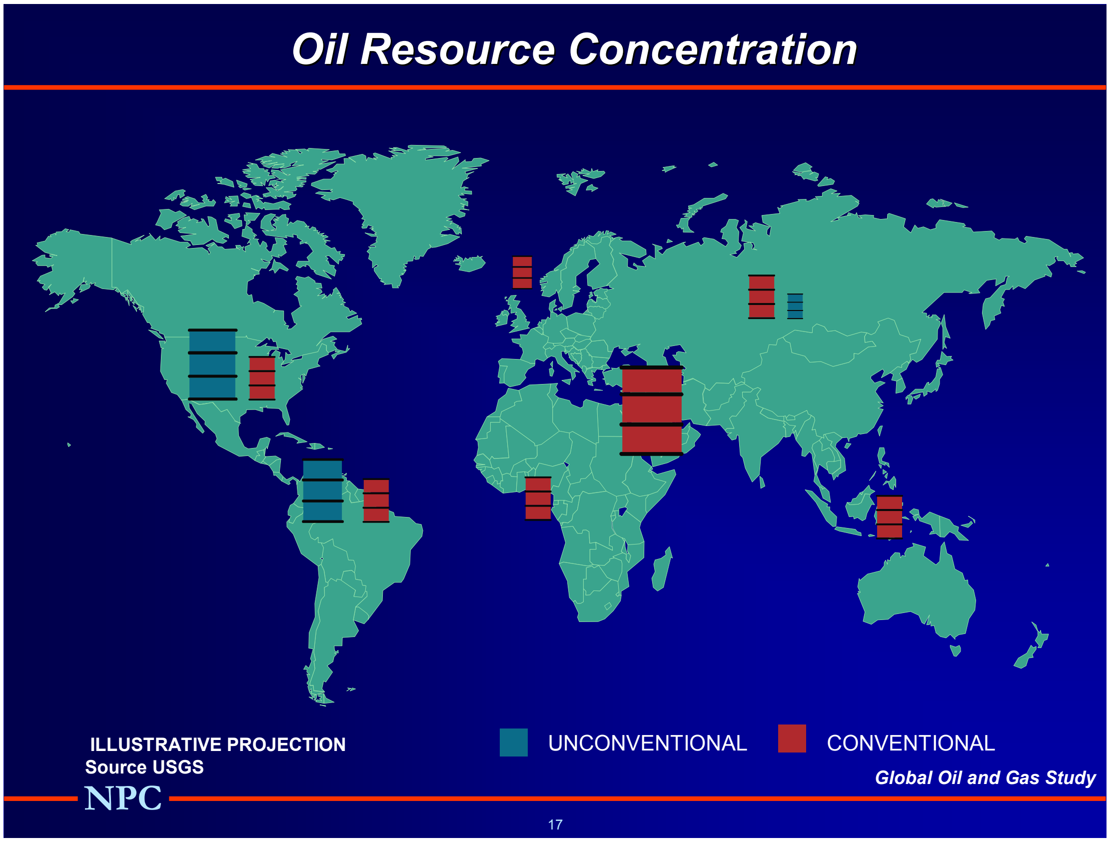
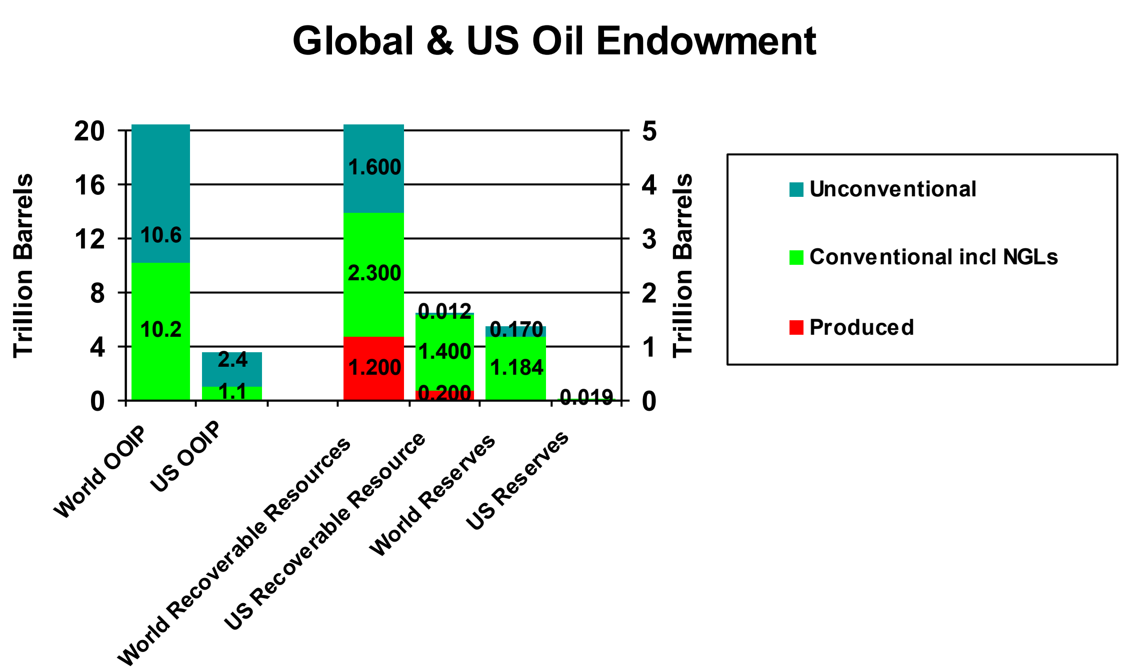


Figure 48: Source – NPC North America Oil/Gas Database



The United States Oil Resource Base has increased over time due to technology enhancements and a greater understanding of new “frontiers”. The United States oil in place for conventional reservoirs is about 11% of the world’s total, while its unconventional reservoirs are 23%. Adding in Canada’s unconventional bitumen endowment, thought to be in excess of 2 trillion barrels, would increase this percentage much more as the chart above shows.

While US crude oil production peaked in the early 1970’s at around 9.6 million barrels per day (MMBD), except for the start up of Prudhoe Bay and periods of high oil prices, it has been on a downward slope (44% from the peak) since 1985. In total, the US imports about half its liquids consumption of nearly 20 MMBD (chart below), equivalent to about one quarter of the worlds liquid demand.

Figure 49: Source – EIA Data

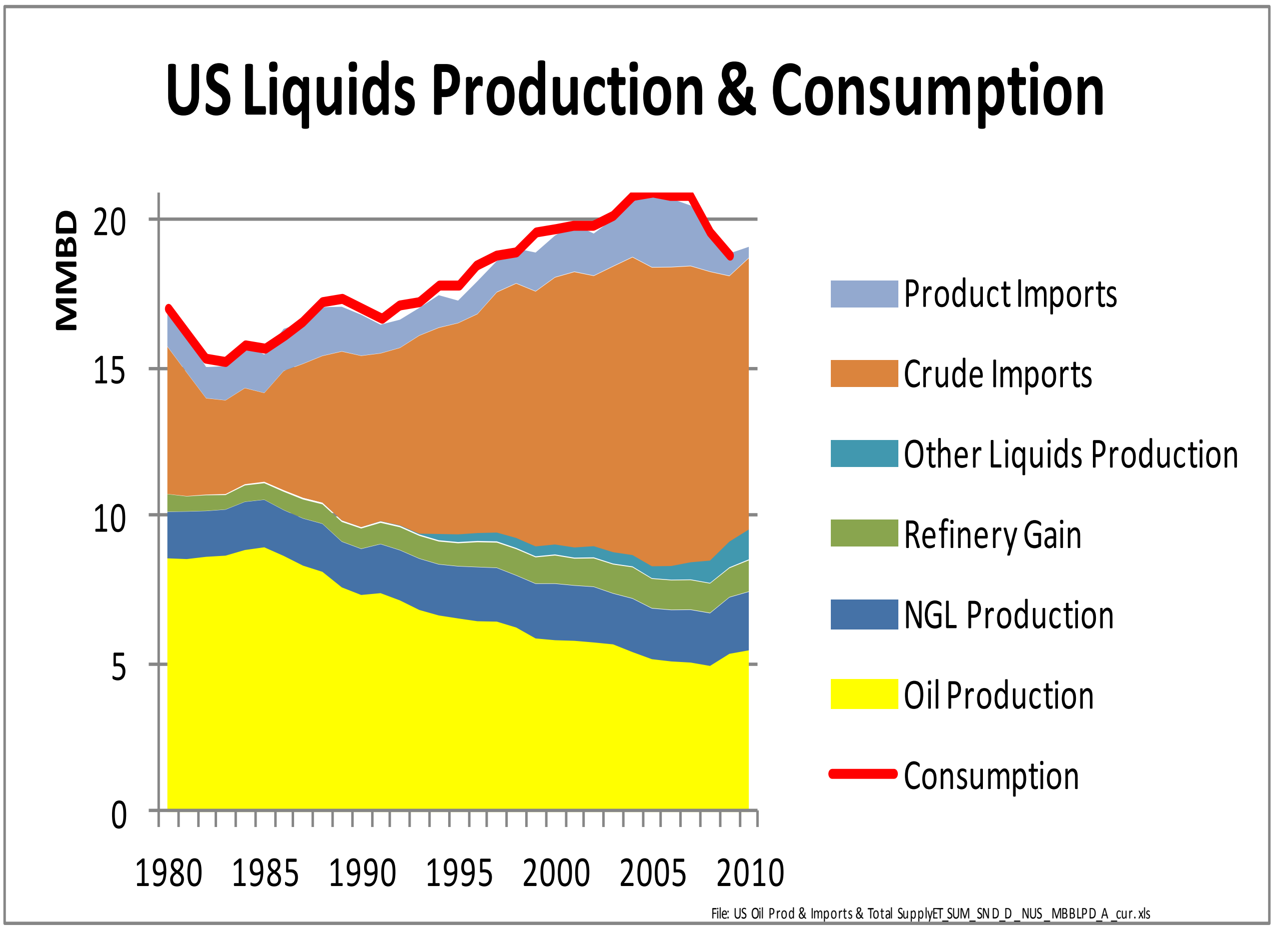
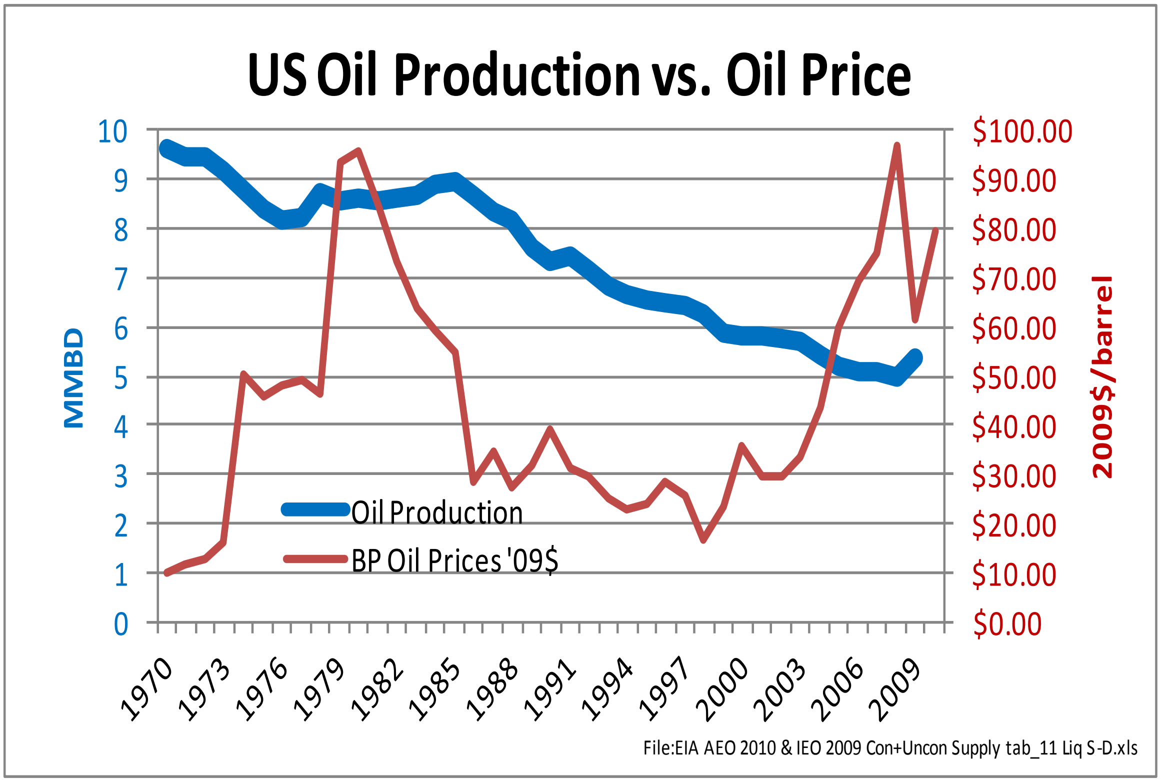
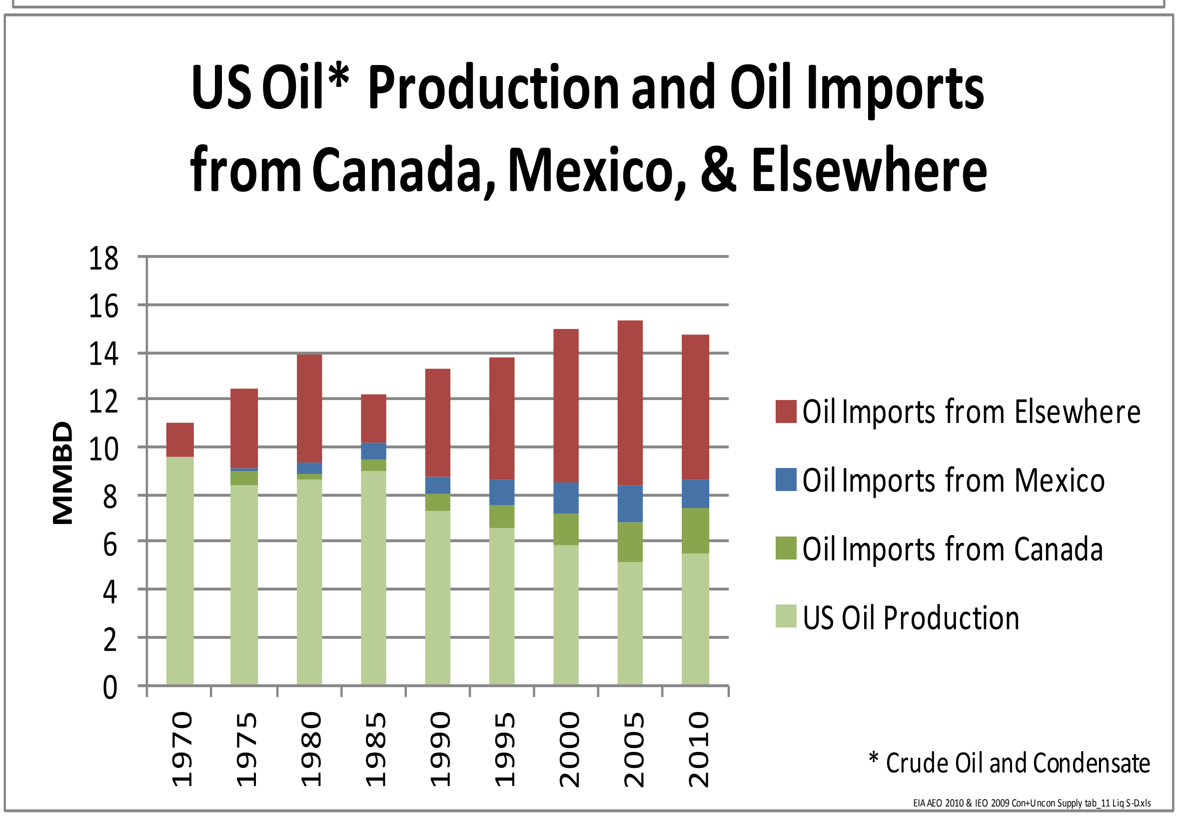


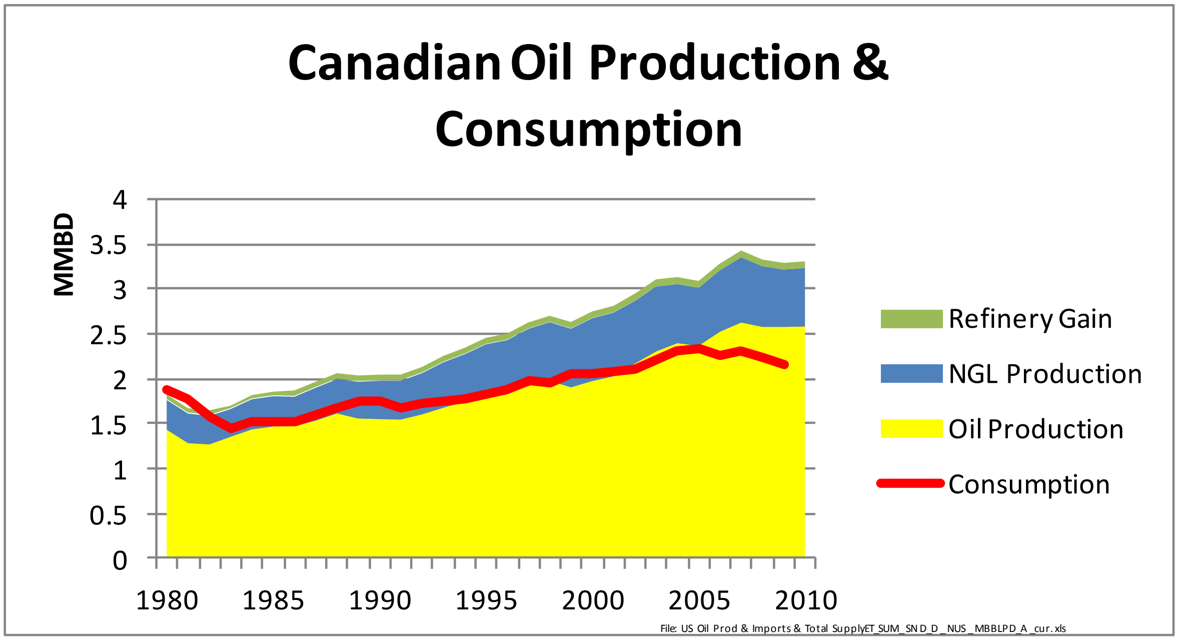
Figure 50: Source – EIA Data

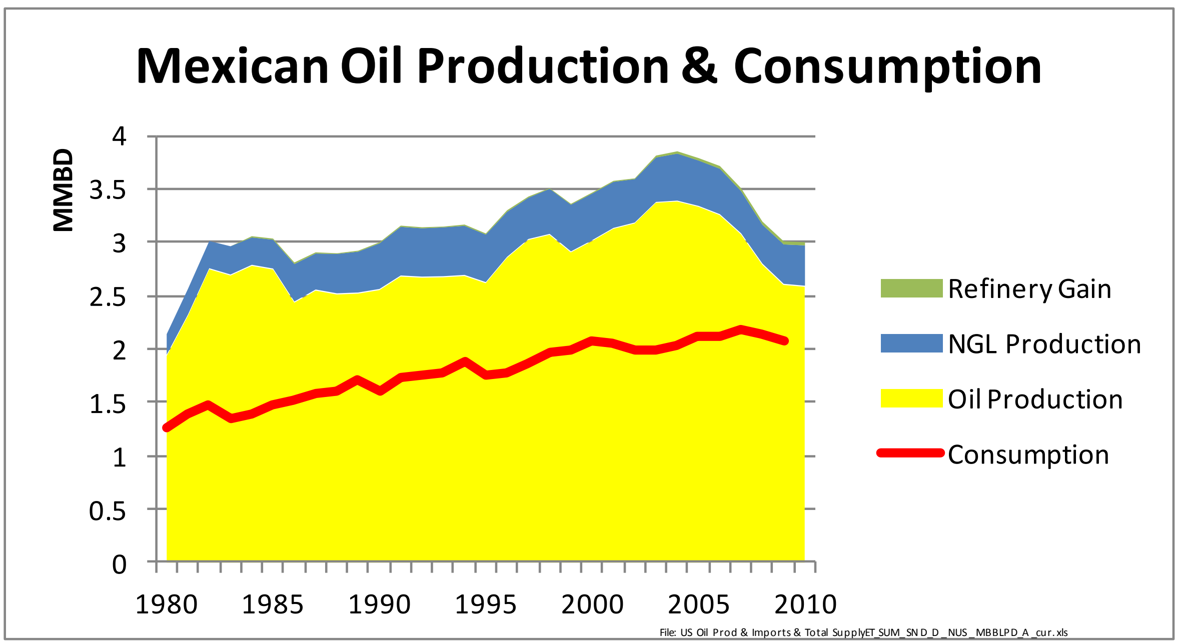




Canada and Mexico liquids production have exceeded their domestic needs (see charts below), allowing the United States to import volumes from its neighbors (in 2010, about 25% from Canada and 15% from Mexico).

Figure 51: Source – EIA Data





The primary questions we hope to address for the North American liquids supply outlook are:

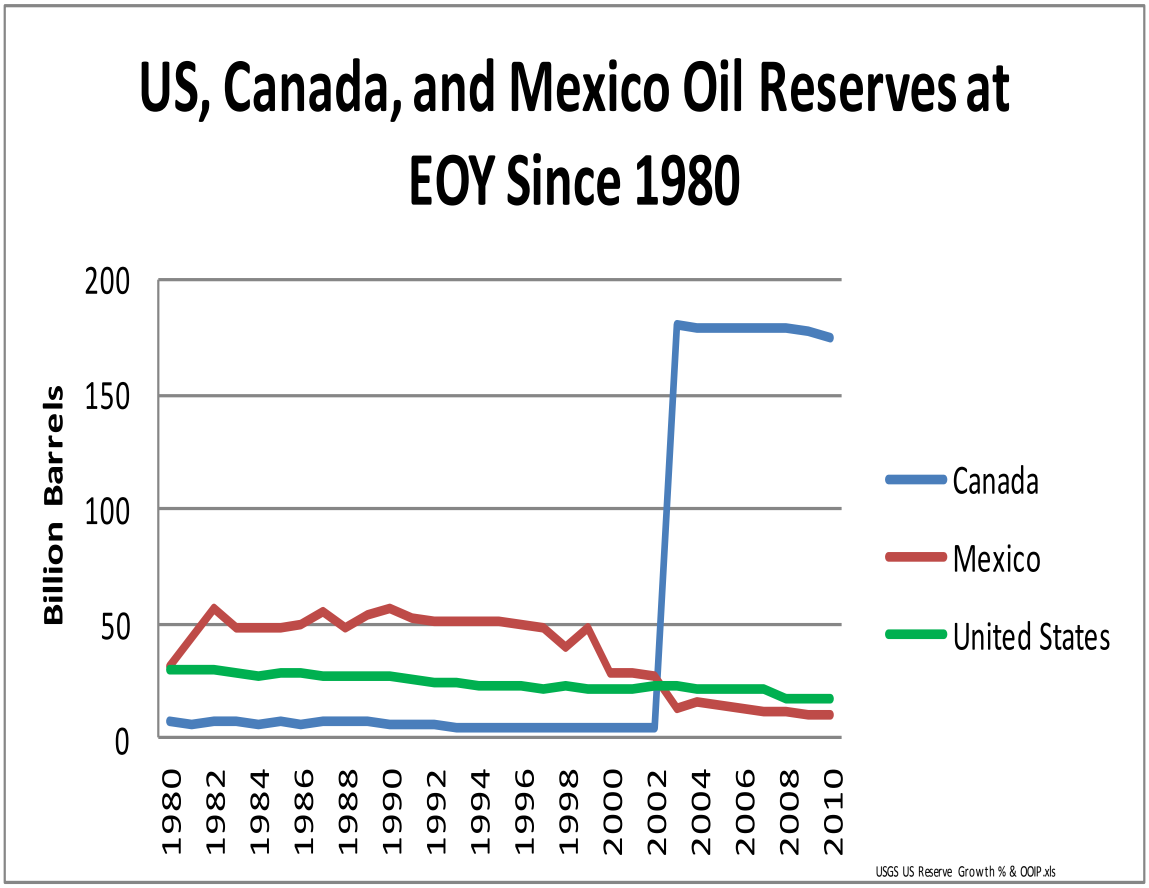
- ❖ What is the anticipated size of the North America liquids supply gap?
- ❖ Can the United States reduce its dependence on foreign liquid imports in the future?
- ❖ What is the magnitude and duration of future Canada and Mexico exports to the United States in light of natural field decline rates, future development opportunities and domestic liquid demand growth needs? Will the US government encourage Canadian oil sand production growth and new long distance pipeline infrastructure into US Gulf Coast refineries or limit access because of environmental concerns?

VI. Oil/Liquids Resource Base & Endowment

While we received very little total North America endowment data, we used the country data to "piece together" an estimate of the remaining recoverable resource base. We believe the remaining NA resource base is likely to be in excess of 500+ billion barrels (BBL), with more than 50% in Canada, 35% in the US, and 15% in Mexico. The resource estimate submitted by the USGS/EIA for the 2007 Global Hard Truths study and a 2009 PEMEX publication both indicated the total Mexican recoverable resource estimate was about 85 billion barrels, with approximately 50 BBL yet to be discovered.

Oil reserves are a subset of the remaining resource base. Reserves only include quantities of crude oil estimated to be commercially recoverable by application of development projects in known accumulations. To qualify as a reserve, these volumes must be discovered, still remaining and commercially recoverable! The US conventional oil reserves estimate is 19 BBL, which is only 2% of the world total. Many countries (e.g. OPEC) have a political motivation to maintain high reserve figures, and some countries are also now counting unconventional barrels in their reserves estimates. Canada, for instance, raised its reserves estimate by about 170 billion barrels in 2003 when it started counting some bitumen resources as reserves. On the other hand, Mexican reserves continue to slide, and without a major change in policy, technology and capital infusion into the E&P sector, it is difficult to see how that trend won't continue in figure 52.

Figure 52: Source – EIA Data



What the Data Says

In the US and Canadian resource base table in Figure 53, we have included three cases that represent the range of remaining resource estimates we received from industry, plus the most recent EIA and NEB released data. The industry's assessment of the United States remaining resource base ranged from 105 - 270 BBL, which is almost entirely restricted to conventional reservoirs at this point. The US's remaining conventional resources are only 6% of the world's total. The US has produced a good portion of its oil in place (OOIP) as a result of being a large producer of oil for a very long time (produced about 200 billion barrels to date – 17% of all oil produced in the world).

Figure 53: Source – NPC North America Study Database

Oil Resource Base Estimates

Billion Barrels	EIA 2011	NPC Low	NPC Mid	NPC High
Arctic	48	25	40	55
L48 Offshore Conventional	57	40	65	100
L48 Onshore Conventional	80	35	50	85
Unconventional "Tight Oil"	34	5	10	15
Shale Kerogen	0 – 750?	0	0	10
Oil Sands	?	1	2	5
US Total Remaining	219	106	167	270
Billion Barrels	NEB 2010	NPC Low	NPC Mid	NPC High
Arctic	20	15	20	25
L48 Offshore Conventional	4	1	2	5
L48 Onshore Conventional	1	1	2	5
Unconventional "Tight Oil"	?	1	2	5
Oil Sands	308	150	170	310
Canada Total Remaining	333	168	196	350

Up until the Macondo incident (BP blowout in the Gulf of Mexico), the exploration results from the Gulf of Mexico were the most encouraging in the United States, with 1-2+ BBL of total exploration success each year over the last two decades. The range of estimates for the US offshore ranged from 40 – 100 BBL, with both the industry mid and EIA reference case estimate at 60 - 65 BBL. The majority of this remaining potential is believed to be in the GOM (40 – 50 BBL) and the Pacific – Offshore California (10 BBL). There is also large potential remaining in the Arctic (25-55 BBL); however it's encumbered by numerous restrictions. The three largest potential areas with additional exploration potential in the Arctic include the North Slope (~18 BBL), the Chukchi (~16BBL) and the Beaufort (9BBL).

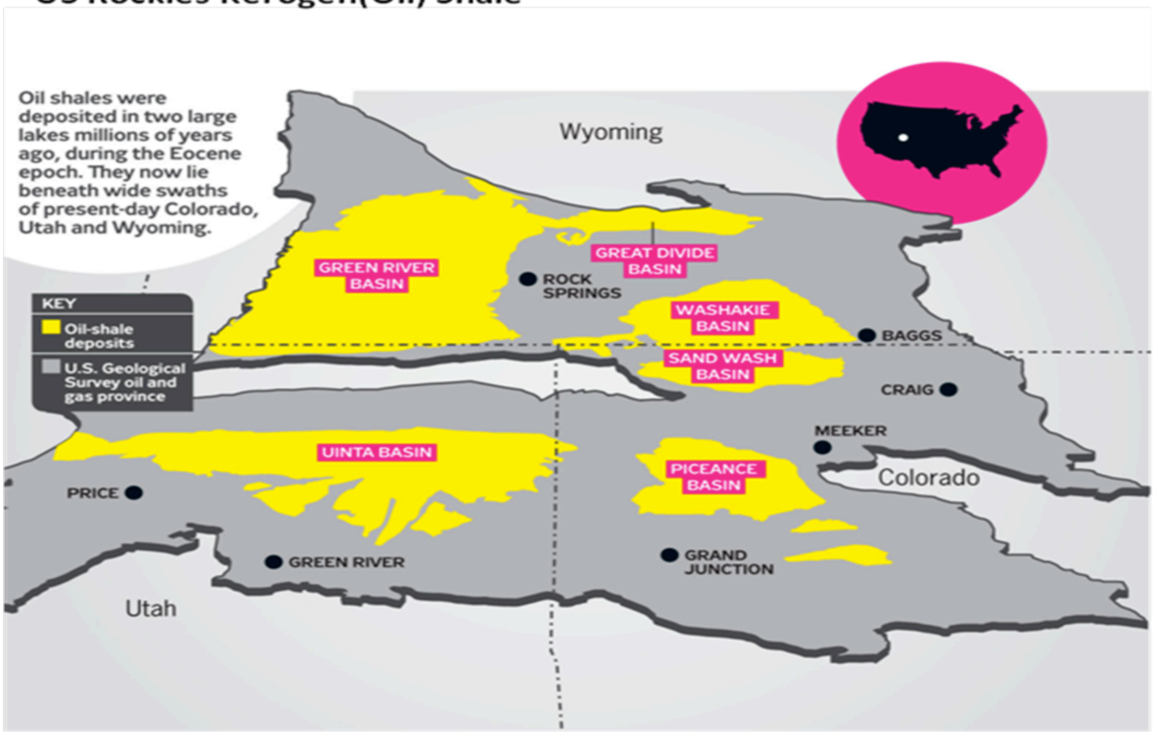
While there are considerable in-place resources in the L48 onshore in both conventional and unconventional reservoirs, there is a lot of uncertainty regarding the recoverable volumes. In the conventional plays, the industry estimates for the remaining recoverable resource base was 35 – 85 BBL. The industry view probably reflects a belief that it is unlikely new, large fields will be found, with most of the additions coming from small fields/discoveries that would be a continuation of the low success rates and discovery sizes in this sector over the last 20 years.

Another component of this remaining resource base includes growth from additional enhanced oil recovery projects on existing fields. The industry believes that it will be costly and challenging to achieve a huge gain above what has been already achieved during the last 30 years of secondary and tertiary recovery using enhanced recovery technologies and techniques. However, several consultant companies carrying out studies on behalf of US government agencies suggest that 40 – 100 BBL may be recovered using natural and anthropogenic CO2. This assumes a very high ultimate recovery rate from existing fields. Moreover, the cost to collect and transport CO2 to many of the possible, new “EOR” candidates (e.g. California fields), together, with clarifying the regulatory and liability “rules”, are a formidable challenge for investors and E&P companies. For example the additional cost for the CO2 supplies and a near to midterm $75 to $100 oil price environment is economically problematic given the alternative domestic and international liquid supplies.

Industry is more likely to continue directing their capital in the L48 to the lower permeability (TIGHT) oil plays such as the Bakken, Monterey, Niobara and also the liquid rich areas of shale gas plays than other L48 opportunities. Currently, the industry estimate for crude and condensate (although considerable NGL volumes are possible) is 5 to 15 billion barrels from tight oil. There are very large in-place volumes (in excess of 2 trillion barrels) of kerogen in the Green River Shale Formation in the Piceance and Uinta basins (see figure 54). In the industry estimates above, only in the high scenario case were recoverable oil resources thought to be “economically” recoverable over the study timeframe. This reflects the additional technology development, pilot projects and high oil price environment required to demonstrate the commercial viability of these resources. Moreover, there are considerable environmental, energy and water use factors that also come into play if and when these plays are developed at a large enough scale that will have a material impact on future US production volumes.

Figure 54: Source – (a) Natureblog.Com; (b) IENEARTH.ORG

US Rockies Kerogen(Oil) Shale



Canadian Oil Sands

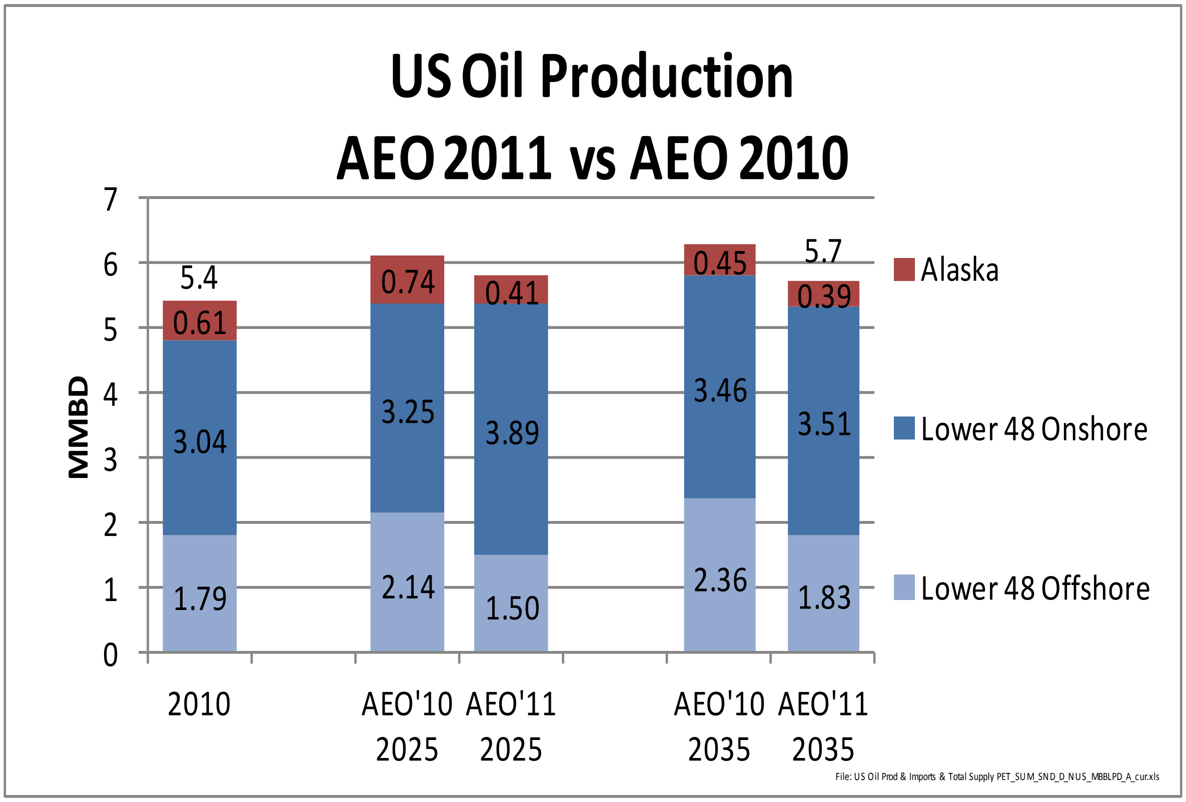
However, industry is currently producing significant volumes from the unconventional Canadian heavy oil sands. This unconventional bitumen resource is one of few North American plays capable of supporting expanded production over both the near and long term. The economically recoverable resource estimates range from 150 – 310 BBL and generally reflect the confidence industry and government stakeholders have in pursuing more costly and challenging areas in the oil sand play. Regardless of the challenges, this North American resource is large by global standards and will underpin liquids production in the region in the future.

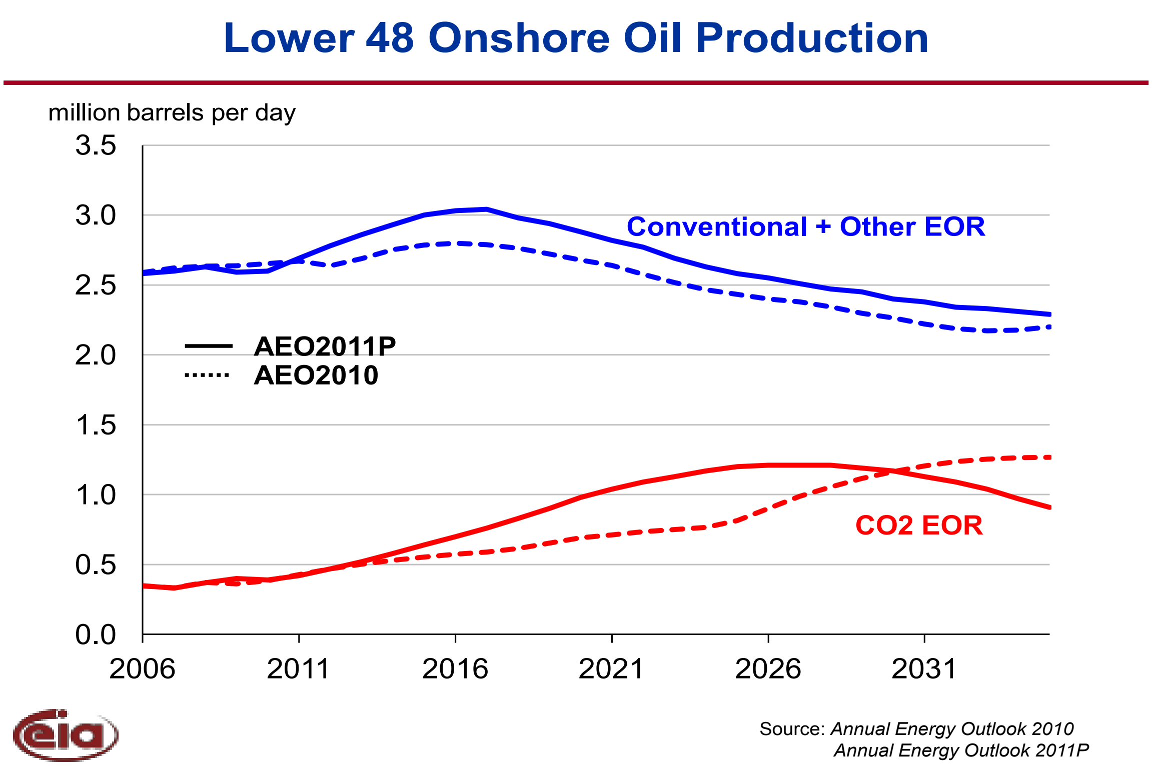
By contrast, the remaining resource potential is negligible in the Canadian conventional sector, with less than 5 – 10 BBL total estimated for the combined onshore and offshore areas outside the Arctic. Industry activity levels are low in these areas, suggesting the magnitude and competitiveness of these areas for investment dollars is low compared to other global oil opportunities. The remaining resource estimate for the Arctic ranged from 15 – 25 BBL's, however there are considerable challenges to exploring for these high supply cost opportunities. However, these exploration targets are large and thus industry is likely to continue evaluating and selectively pursuing these in the near to long term. The Beaufort Sea (~7 BBL) and Sverdrup/Arctic Islands (~5 BBL) are believed to have the most remaining potential.

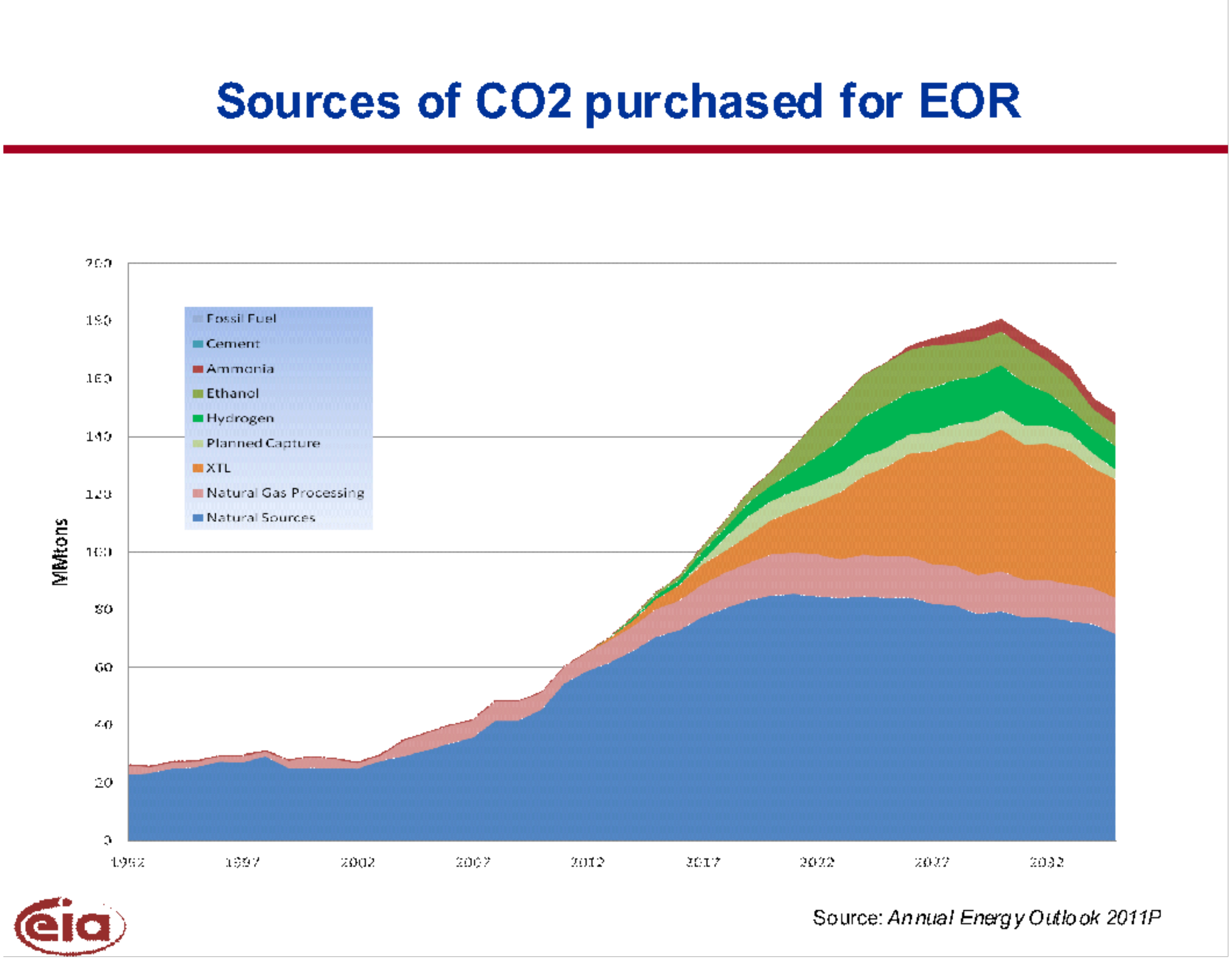
VII. Oil/Liquids Production Capacity & Outlook

In the IEA AEO2011 Reference case, U.S. domestic crude oil production is forecasted to increase from 5.4 mmbd in 2009 to 5.7 mmbd in 2035 which represents a +0.3% CAGR, despite a -1.4% CAGR since 1970. Cumulatively, oil production in the lower 48 States in the AEO2011 Reference case is approximately the same as in the AEO2010 Reference case, however the distribution from various sectors differs in that more onshore and less offshore oil is produced in AEO2011 (see figure 55). Onshore oil production is higher in AEO2011 as a result of an increase in EOR (enhanced oil recovery), as well as increased oil production from shale oil sources which have been included in the onshore conventional production wedge as wells as the inclusion of Rockies oil shale volumes out in 2035. EOR accounted for 33 percent of cumulative onshore oil production.

Figure 55: Source – EIA Data





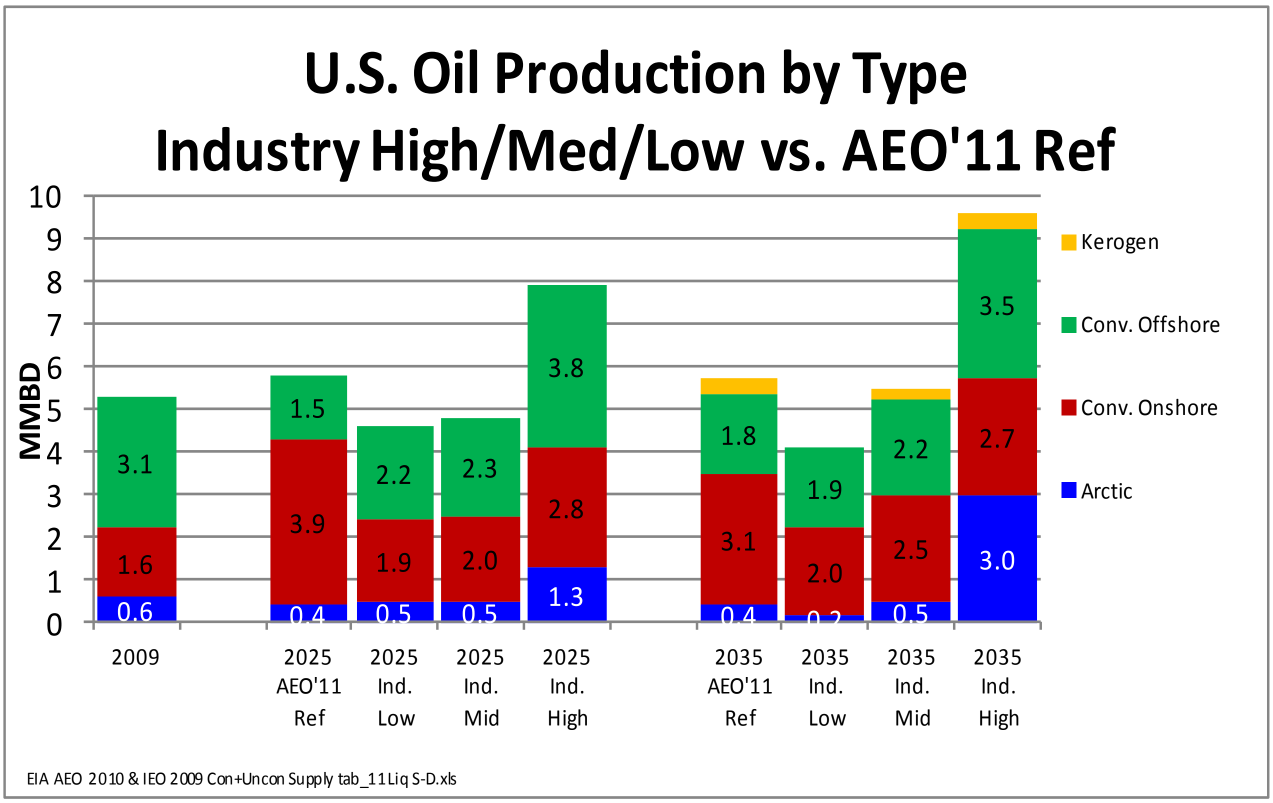


However, other outlooks collected in this study suggest the assumptions regarding this recent EIA case may be difficult to achieve by 2035. The bulk of the EOR production uses CO2. For CO2-enhanced EOR oil production, naturally produced CO2 or man-made CO2 captured from sources such as natural gas plants and power plants is injected into a reservoir to reduce the residual oil saturation in the reservoir. A skeptic would suggest that the EIA's bullish view underestimates the difficulties and costs associated with CO2 collection and distribution, and assumes a good response to the flood. Liability issues have also not been adequately addressed. For instance, where does the potential liability for possible CO2 leakage resulting from CO2 injection storage and sequestration lie?

The Data and Study Analysis Team obtained a wide range of industry and consultant views on oil resources and production supply capacity. The total US production volumes in the EIA reference case and the industry mid case were relatively similar by 2035. The industry/consultant mid case oil total production forecasts were lower by 1 mmbd than the AEO 2011 forecast in 2025. Consequently, the Industry's oil production CAGR from 2009 until 2035 was 0.1% versus 0.3% in the AEO's 2011 Reference Case. Generally, the Industry's median case was much less bullish for the onshore sector (likely EOR projects).

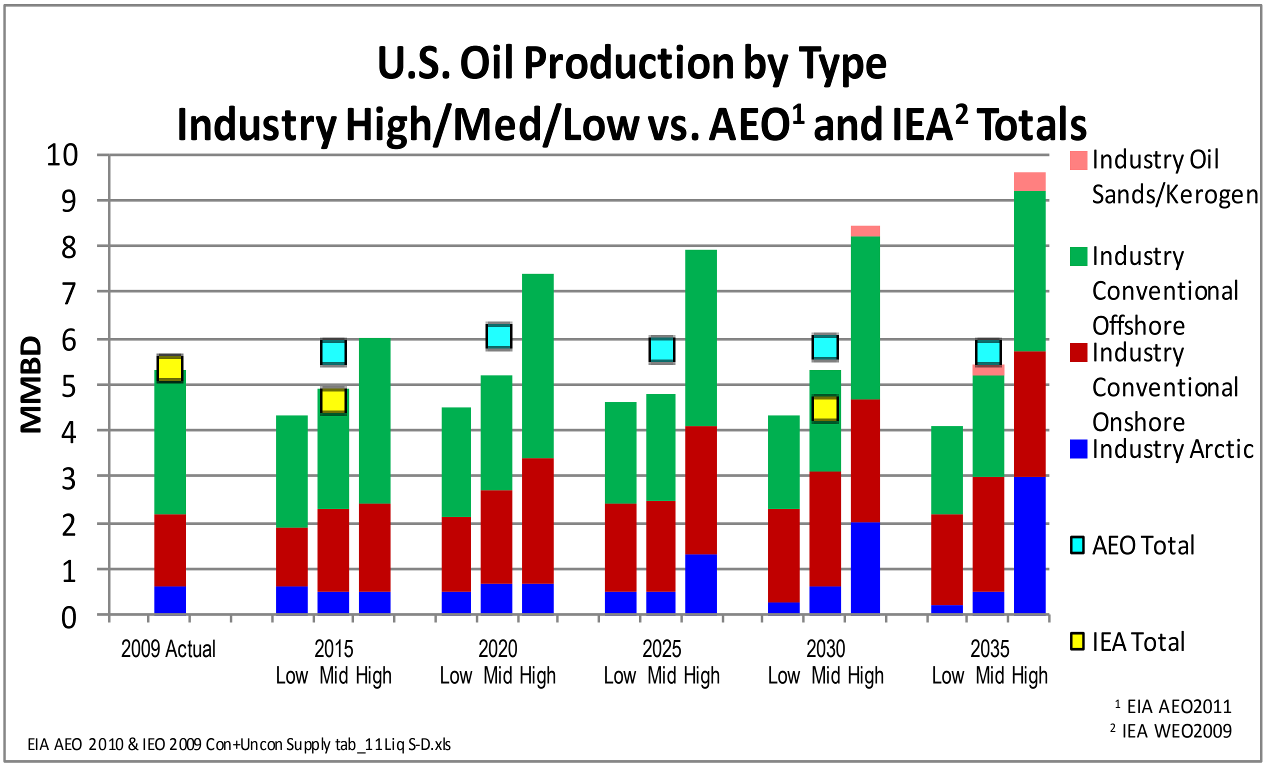
The industry was more aggressive on resource additions on offshore production levels, however, there is uncertainty regarding assumptions for future activity levels in the offshore (L48 and Arctic) following the Macondo incident. The 2011 EIA reference and industry views were relatively similar for growing production in the Arctic. This likely represents general alignment on the relatively high supply costs anticipated for future exploration and development projects in the Arctic and the challenges associated with offshore drilling given the implementation of the new regulatory requirements for spill preparedness and liability following the Macondo blowout.

Figure 56: Source – NPC North America Study Database



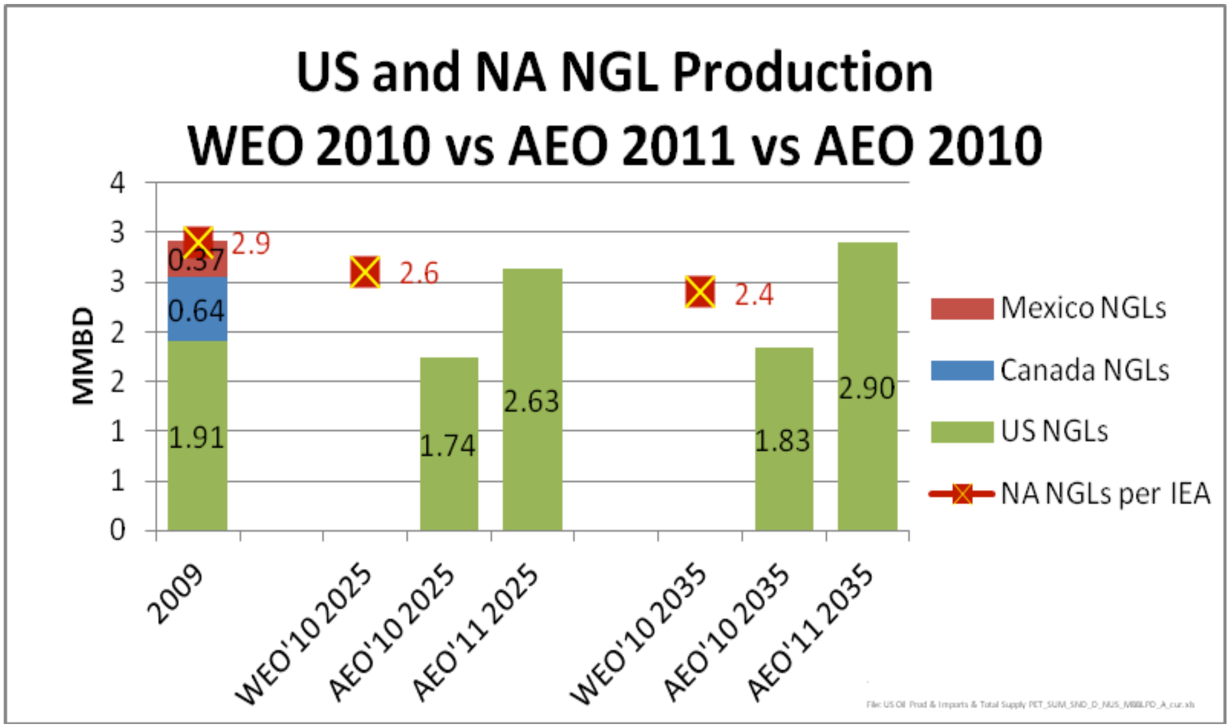
The industry's high case US production levels were significantly greater than the AEO 2011's Reference Case, with a 2.3% CAGR. In this case, Industry cited big production gains in Alaska and Offshore, no doubt based on the assumption of increased acreage access in areas that are currently under moratoria. Consultant studies on the behalf of various US government agencies suggested there is between 30 – 50 billion barrels that is inaccessible to industry at the present time. Finally, we also compared the range of industry cases with the IEA WEO Current policies case. The IEA production output levels generally coincided with the mid industry case.

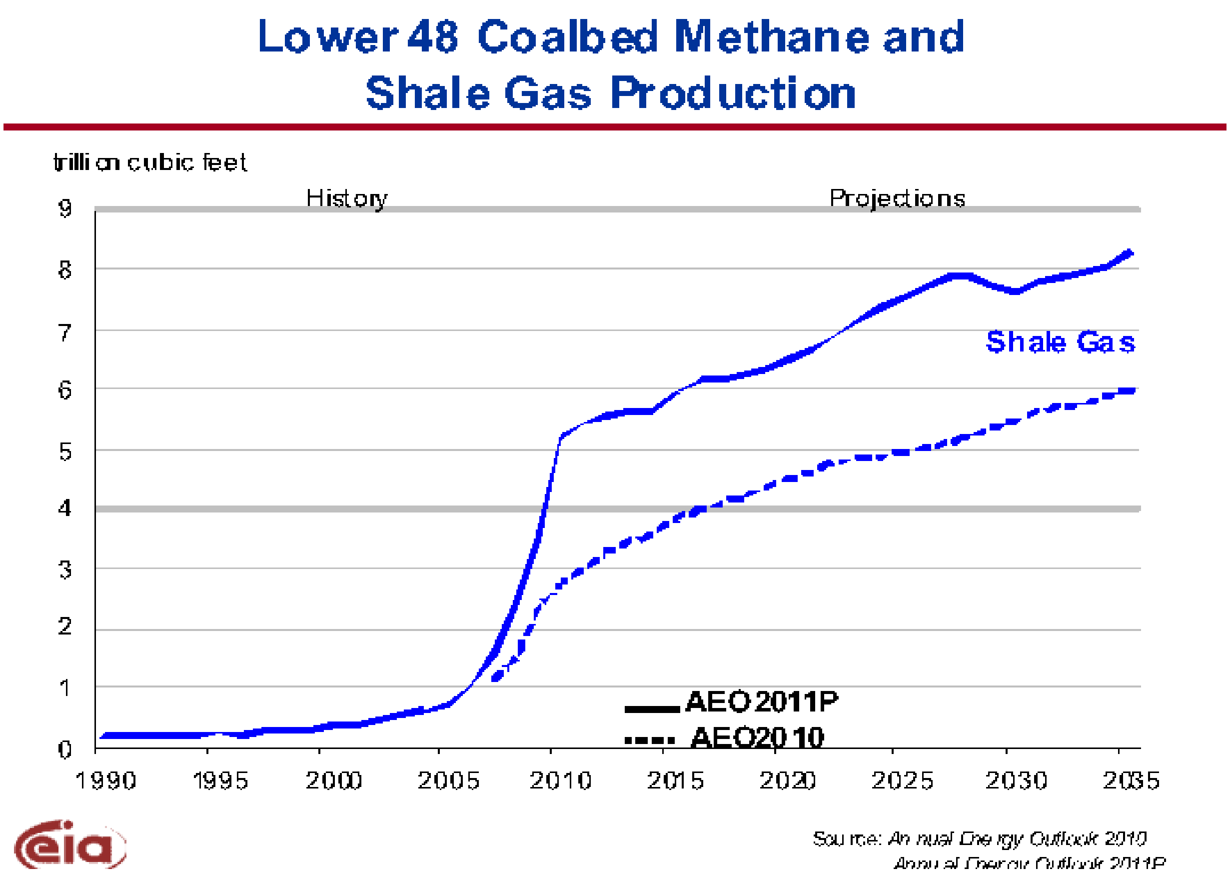
Figure 57: Source – NPC North America Study Database



One of the biggest differences in AEO's 2011 versus 2010 US liquids production forecast is the Natural Gas Liquids (NGL) forecast. As figure 58 shows, the AEO 2010 reference case had a much lower shale gas production forecast than AEO 2011 reference case. The EIA now anticipates shale gas producers are going to focus on maximizing wet gas production. Consequently, EIA's 2011 AEO US NGL production is up 1 mmbd by 2035 over 2009 (2.90 vs. 1.91 mmbd), versus being slightly down in their 2010 forecast (1.83 vs. 1.91 mmbd). While not forecasting US NGL production explicitly, *IEA's* North American NGL production forecast is down 0.5 mmbd by 2035 (2.4 vs. 2.9 mmbd).

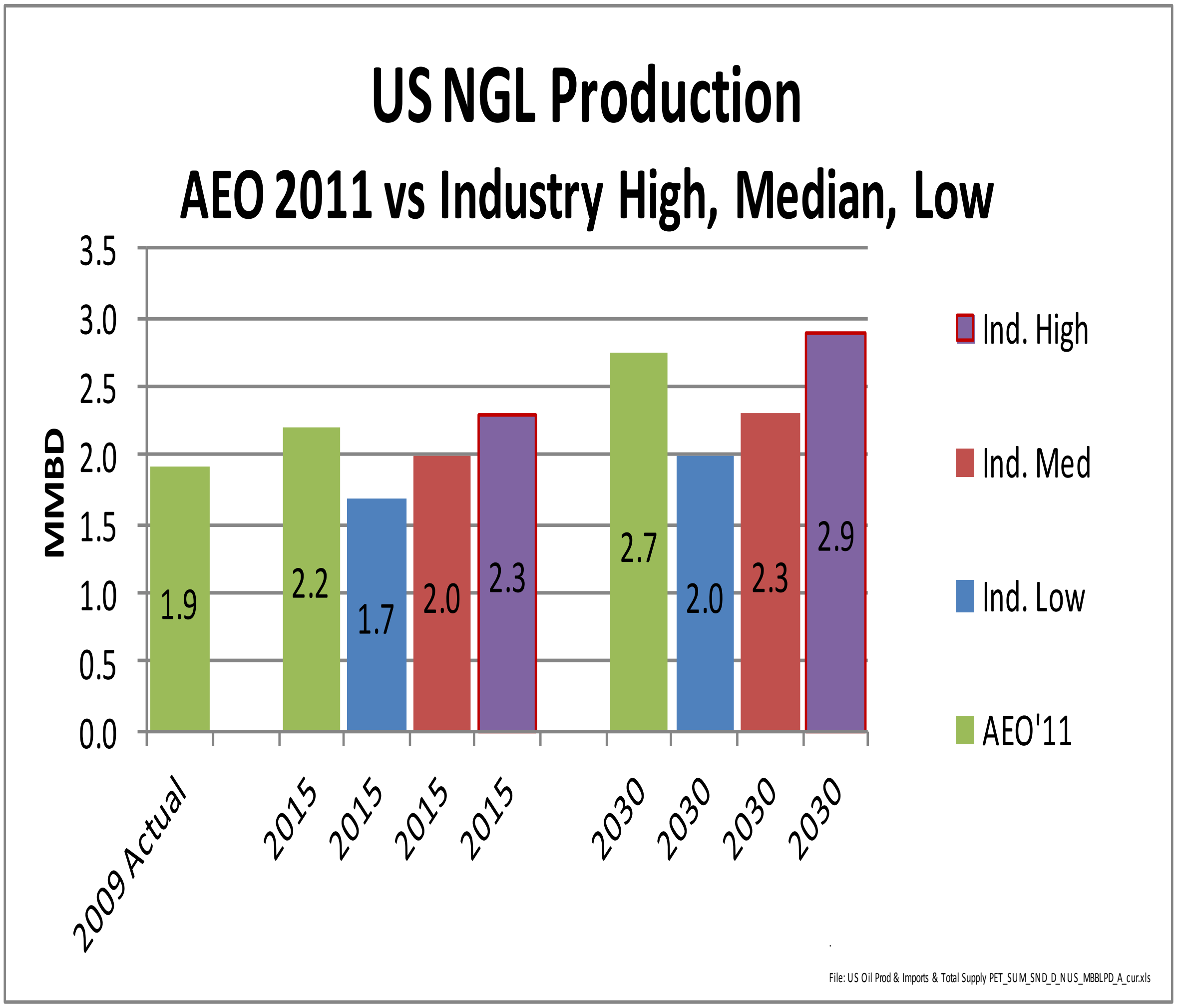
Figure 58: Source – EIA and IEA Data





The Data Study Analysis Team obtained some Industry/Consultant US NGL data that has been displayed in the chart below. As can be seen, the Industry's mid (2.3 mmbd) and high (2.9 mmbd) forecasts in 2030 bound the AEO 2011 forecast of 2.7 mmbd, while the Industry's low (2.0 mmbd) forecast is relatively flat through 2030.

Figure 59: Source – NPC North America Study Database



In order to achieve the EIA's 2011 reference and the Industry's high forecast for 2030, one would have to assume that another 0.8 - 1.0 mmbd of additional NGLs by 2030 would not flood the US NGL market and drive LPG prices down (currently about 0.2 mmbd of LPGs are imported into the US). Given that historically about half of the NGLs produced in the US have been ethane, this is a difficult argument to accept. More likely, once shale gas producers produce so much wet gas that LPG prices start to fall precipitously, they will collectively back away from producing more NGLs than the market can absorb – and end up producing only enough additional NGLs to back out LPG imports plus meet rising demand from any new US ethylene plants.

While the Data and Study Analysis Team was not tasked with assessing the total US liquids production, including biofuels and FT-liquids production, we believe it is necessary to look at total liquids to compare *IEA* forecasts – which didn't provide much granularity – with EIA forecasts. EIA's AEO 2011 outlook has a 1.2% US Total Liquids Production CAGR for 2009 versus 2035. Decomposing this CAGR, oil production only has only a 0.3% CAGR (as mentioned above), while production from the other liquids has a CAGR of 2.3% (in the above chart). The EIA's total liquids 1.2% CAGR is much more bullish than the 0.4% CAGR from *IEA* for 2009 versus 2035. Part of the difference is the NGL forecasts mentioned above involving liquids production from shale gas. Removing NGLs from each forecast drops the EIA CAGR to 1.1% and improves the *IEA* CAGR to 0.8%, narrowing the difference between the two forecasts considerably. This probably shouldn't be too surprising considering that EIA's and *IEA's* oil price forecasts are similar (see figure 61).

Figure 60: Source – EIA 2010 and 2011 AEO

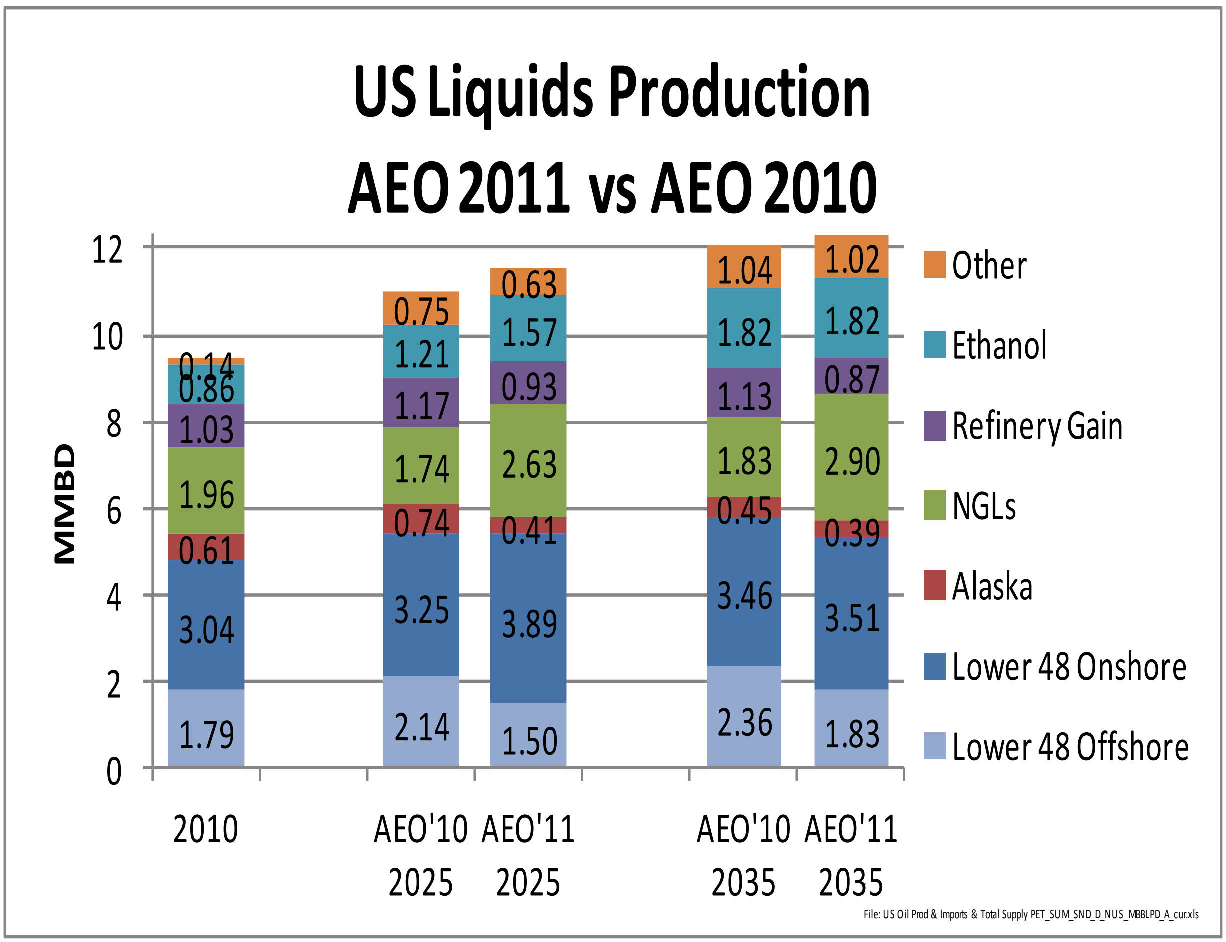
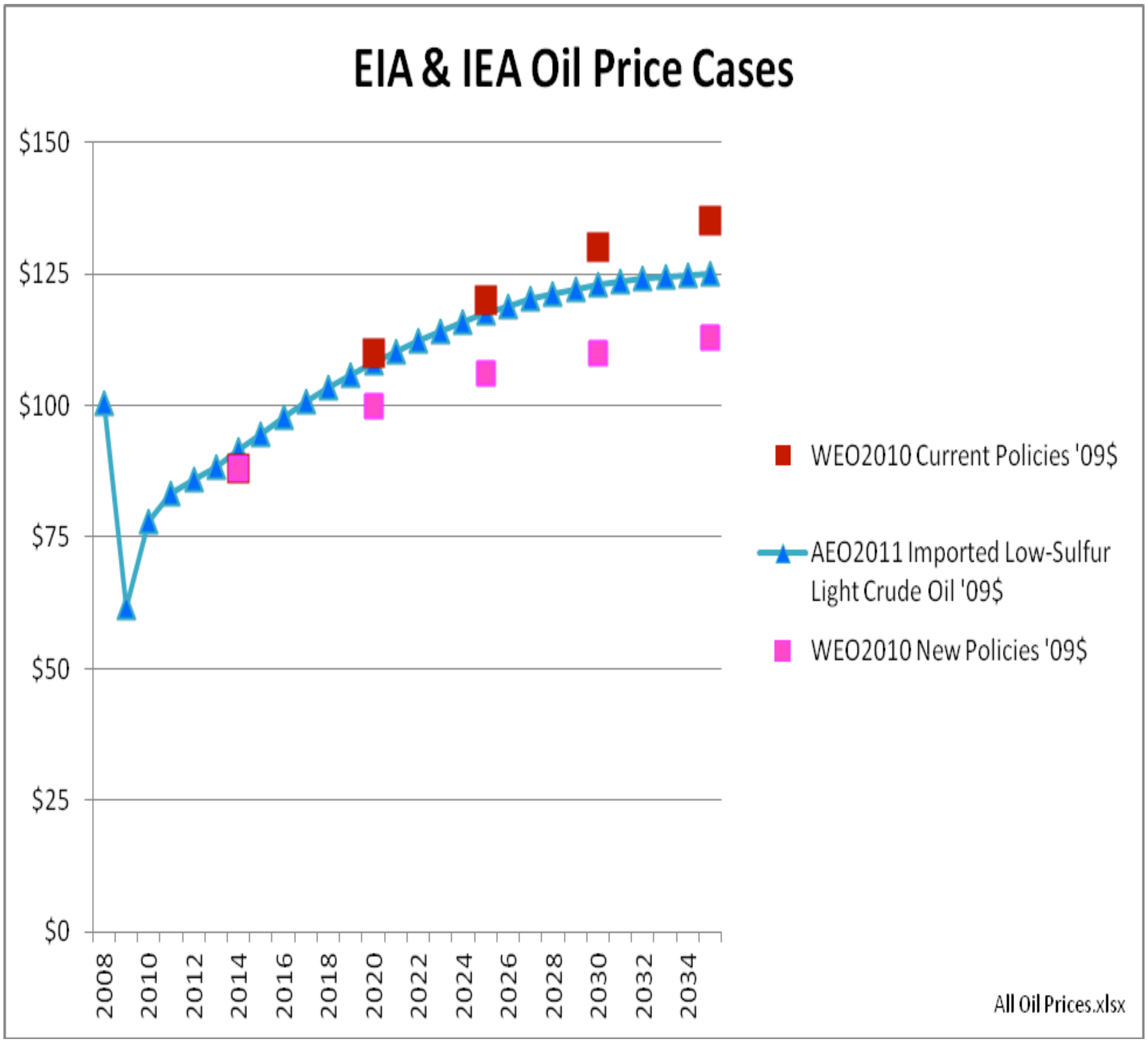
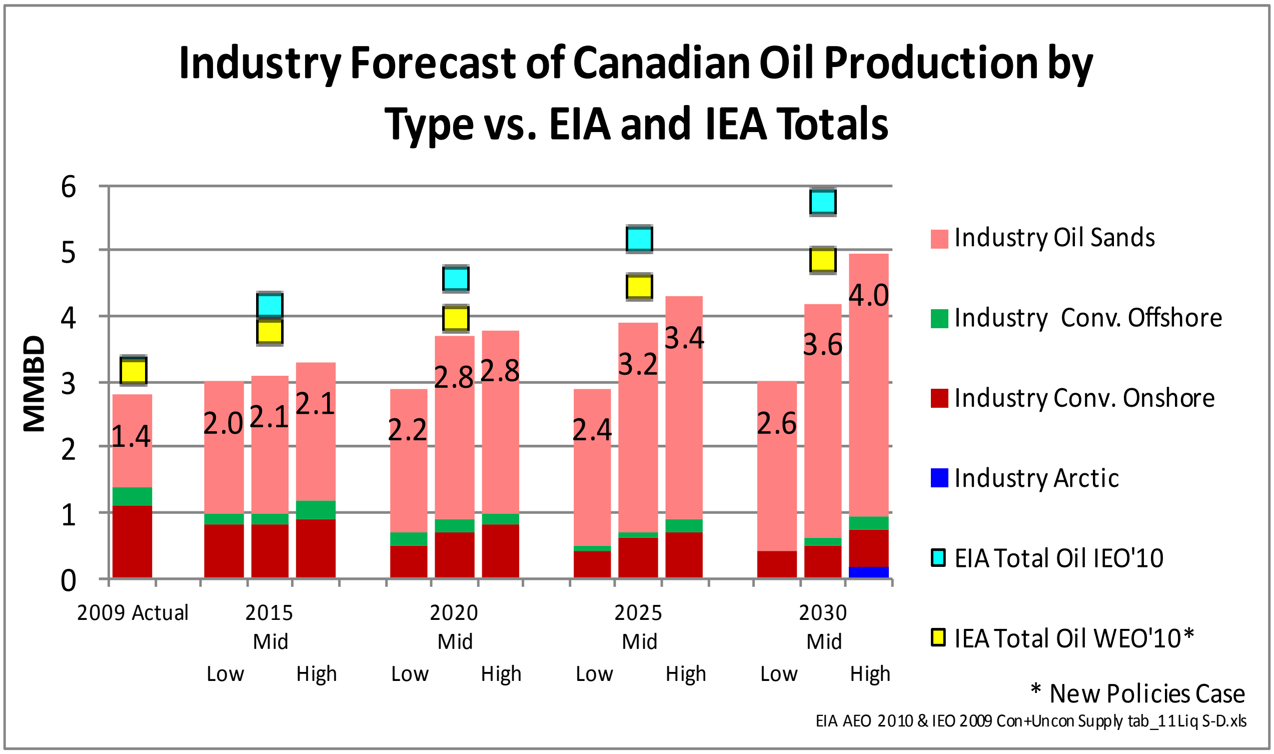


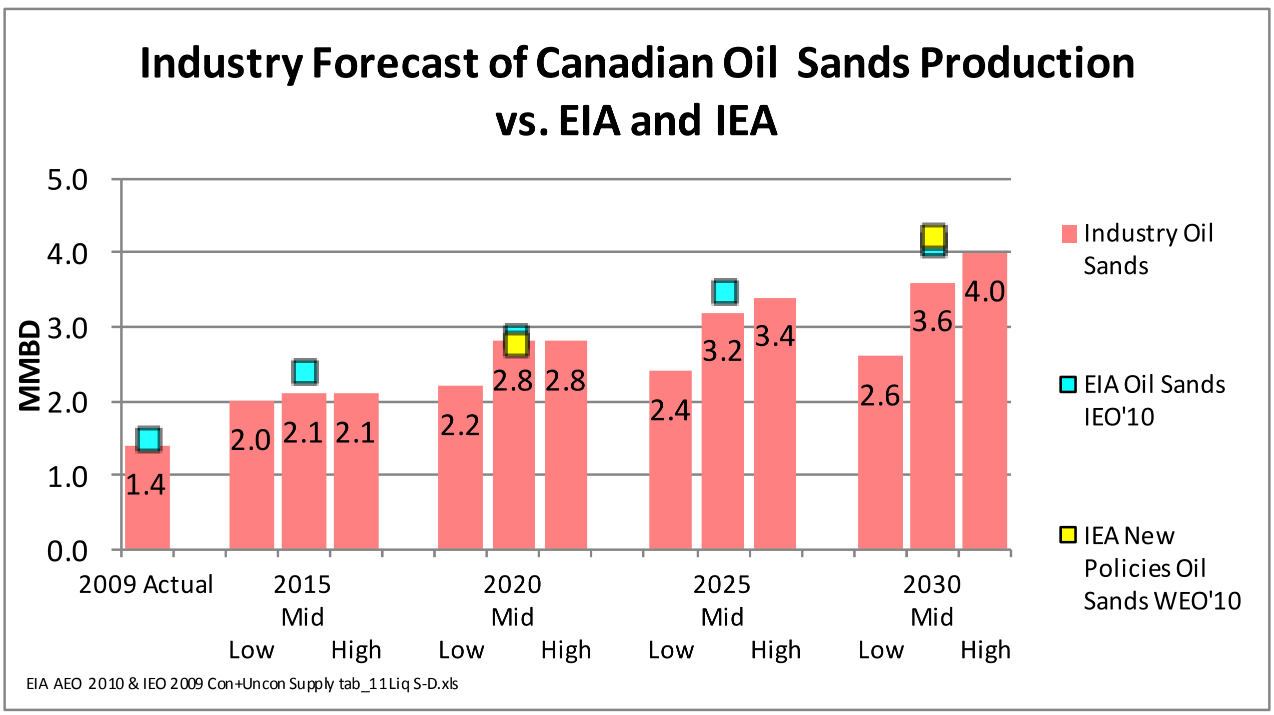
Figure 61: Source – EIA and IEA Data



A wide range of industry and consultant views (see figure 62) was received regarding the future Canadian production output. The industry mid case oil total production forecasts were quite a bit lower than EIA's forecast, and just below *IEA's* forecast total in all years. At 1.9%, Industry's median Canadian oil production CAGR from 2009 until 2030 was just slightly less than *IEA* at 2.0%, but well below the EIA's Reference Case Canadian oil production CAGR at 2.9%. The industry and consultant high scenario provided a 2.8% CAGR, just below EIA's Reference Case CAGR estimate. In all the cases, the conventional oil production from the onshore and offshore declined due to the high field decline rates and relatively small remaining potential in both Western Canada and the offshore (Atlantic). Moreover, no significant production was also anticipated in the Arctic, probably a result of the high supply cost of these large, remaining resources; together with the absence of infrastructure or cost effective transportation mechanisms to get these remote resources into the market place. The Arctic projects have long lead times, so industry and government stakeholders should work together to continue collecting data to assess the size of the resource base and be prepared to bring these supplies on-line as soon as commercially feasible.

Figure 62: Source – NPC North America Study Database

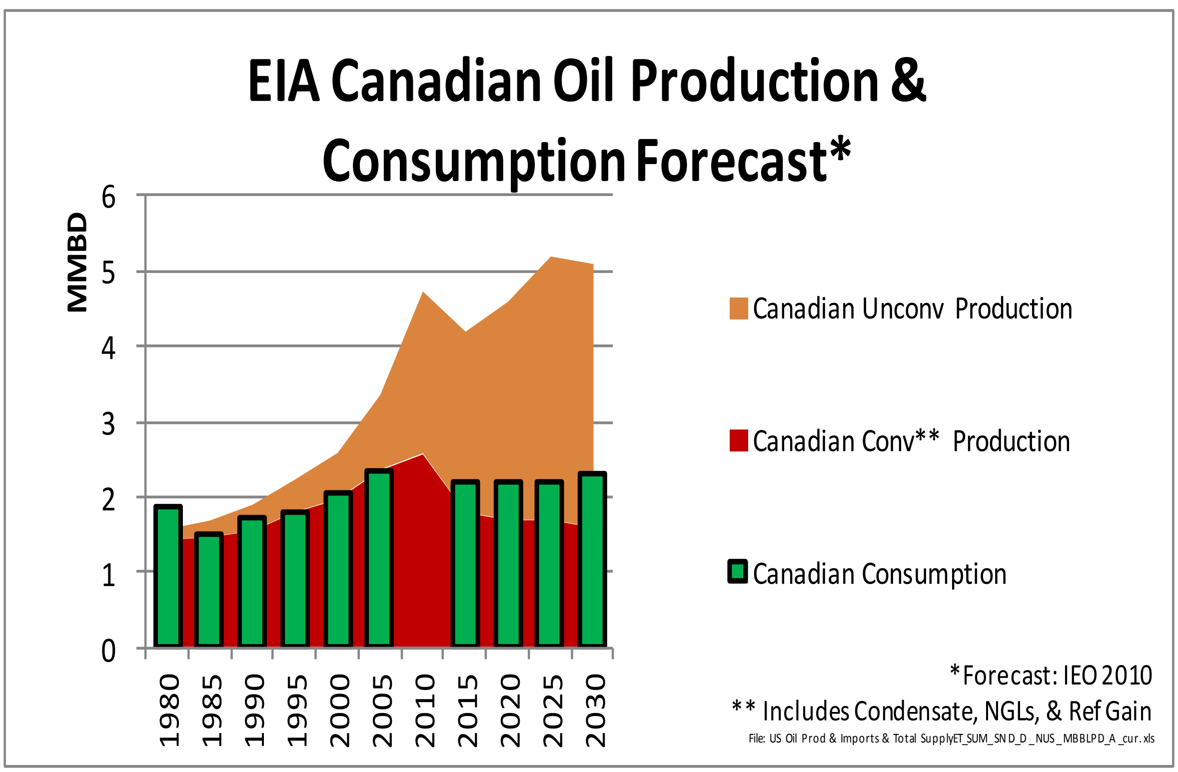


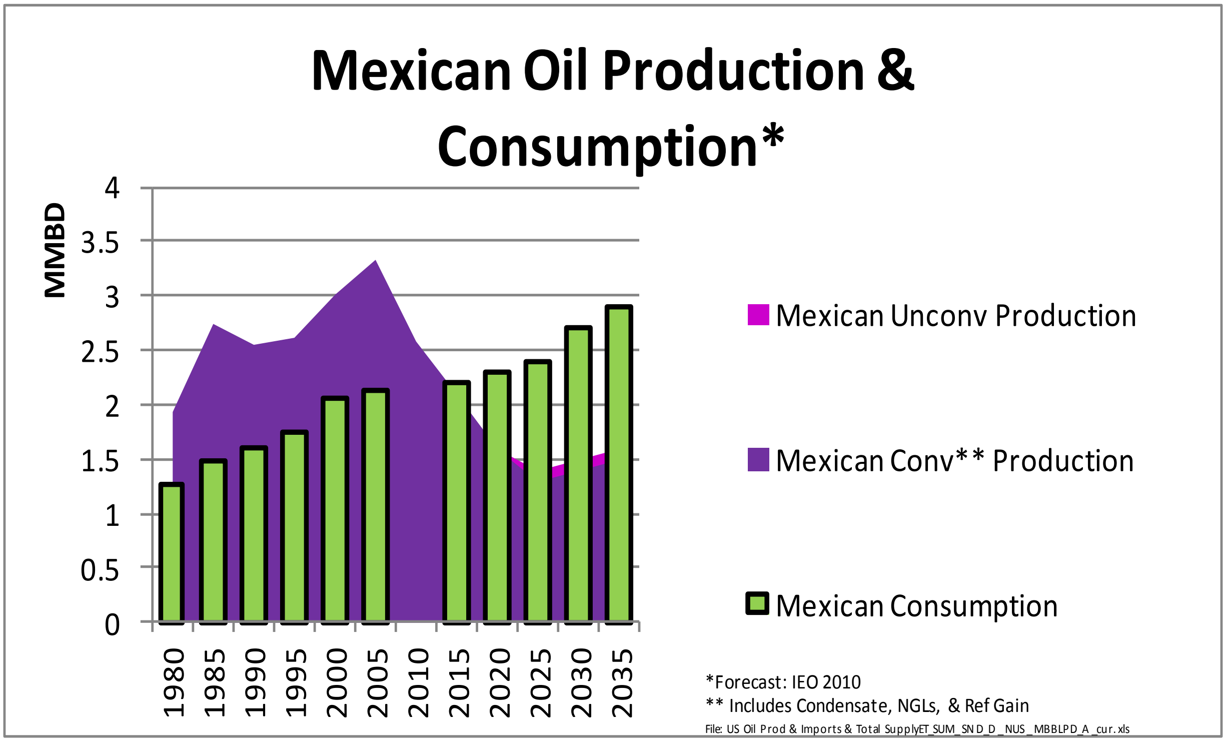


The major differences in the cases illustrated in figure 62 are predominantly due to the production levels for the Canadian oil sands, which is the largest component. The Industry's median case is only 3.6 mmbd – a significant 600 mbd below the agency forecasts commercially available resource play in North America. Through 2020, given the long lead time and general understanding of the projects slated to move forward, for 2030, the differences between the three Industry forecasts and the EIA and *IEA* cases are minimal. Even the industry's high case at 4.0 mmbd is below both the EIA and *IEA* cases at 4.2 mbd. Clearly, industry is more conservative about overcoming the above ground challenges to rapidly grow production, especially in light of the additional pipeline infrastructure that will be required to either bring additional volumes down the refiners on the US Gulf Coast (e.g. Keystone project) or consider exporting crude to Asia Pacific, which would required a new infrastructure network from Alberta to the Canadian west coast.

Based on the oil demand forecast for Canada, the EIA expects oil exports (US imports) to grow with time. This is also is true for the industry cases, however the magnitude of growth is dictated by the ability to develop new projects and infrastructure and the US and/or Asian market pull. Unfortunately, the Mexican productive capacity and exports (US imports) are rapidly declining and ultimately Mexico may need to import additional oil to meet its growing consumption before the end of this decade.

Figure 63: Source – 2010 EIA IEO





In summary, the future of North American future oil supplies in the near to longer term are heavily dependent on the US offshore (somewhere between 40 and 100 billion barrels are thought to be economically recoverable) and Canadian oil sands (which holds somewhere between 150 and 310 billion barrels of economically recoverable resource). Production from EOR, tight oil, shale oil, and coal from liquids will contribute to some supply growth, however, it is probably prudent not to count on them too heavily, especially given the large decline rates in the US onshore and challenge to continue delivering around 3 or more million barrels a day from this sector over the study time frame. More importantly, if regulation prevents access to the US offshore, or prohibits transport of Canadian oil sands, then its likely North American oil production will decline, especially in light of Mexico's declining liquids production outlook.

In figure 64, the US and Canadian combined, total conventional oil production has varied from 8.4 mmbd in 1995, to 7.5 mmbd in 2005, to 8.1 mmbd today. The EIA is forecasting that conventional oil sectors will slowly trend down to 7.3 mmbd in 2035. However, they have Canadian oil sands production growing significantly and driving total North American oil production to over 11 mmbd by 2035. When comparing EIA's US+Canada oil production forecast with *IEA's* and the Industry's, the EIA case comes is the most optimistic with the exception of the industry's high case (see figure 65). The *IEA* is forecasting 2030 US+Canadian production 1.5 mmbd lower than EIA. The Industry's median case ends up being about the same in 2030 as *IEA's*, whereas its low case, which should serve as a warning signal for all stakeholders, forecasts only 7.3 mmbd, a full 3.6 mmbd lower than EIA's forecast.

Figure 64: Source – 2010 EIA IEO

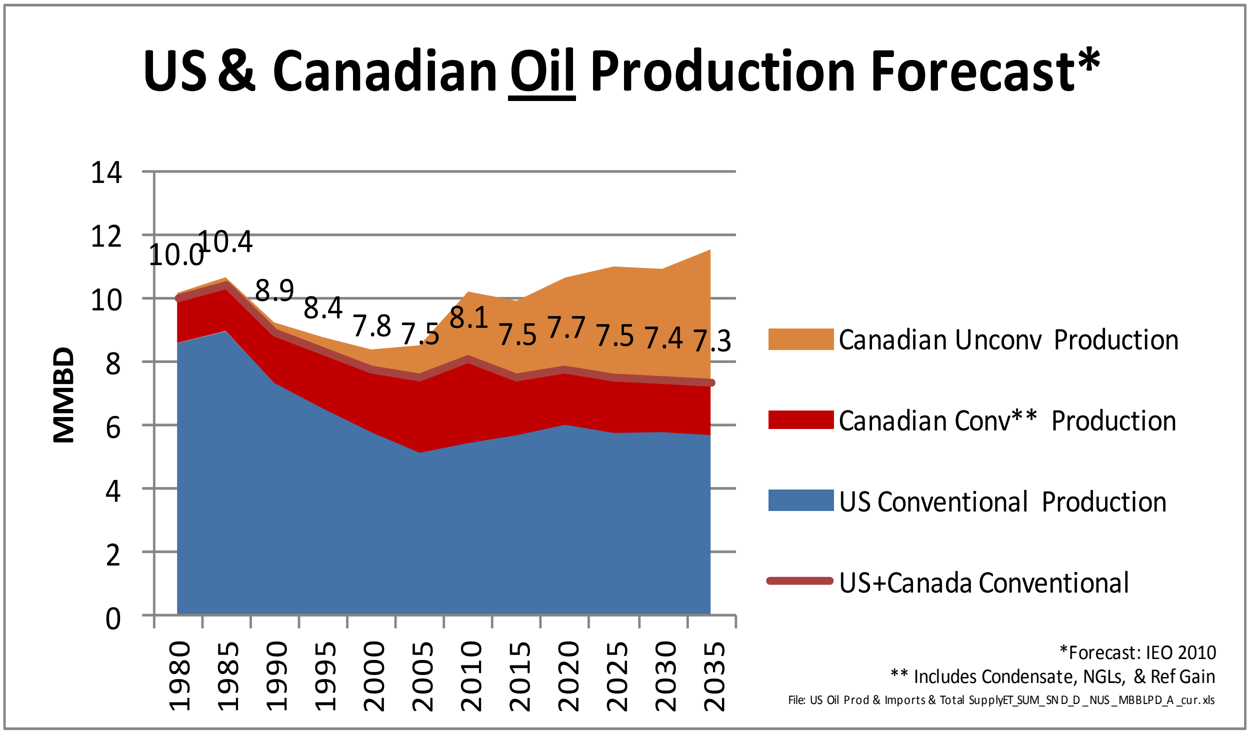
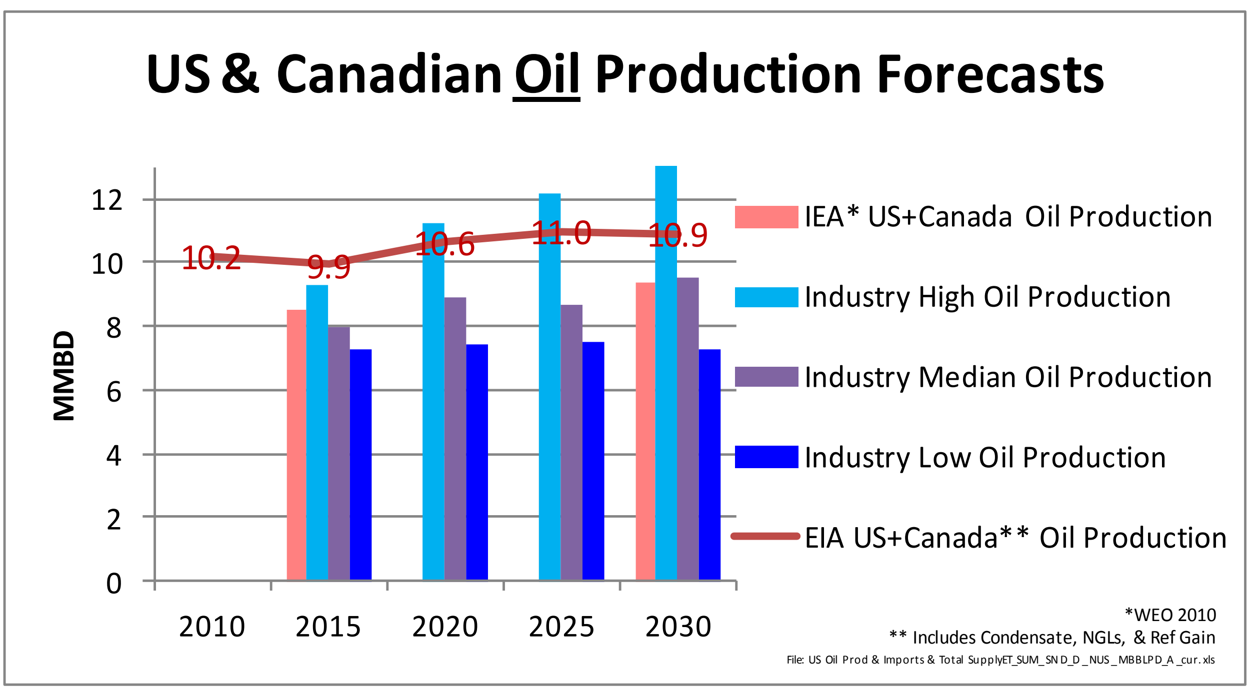
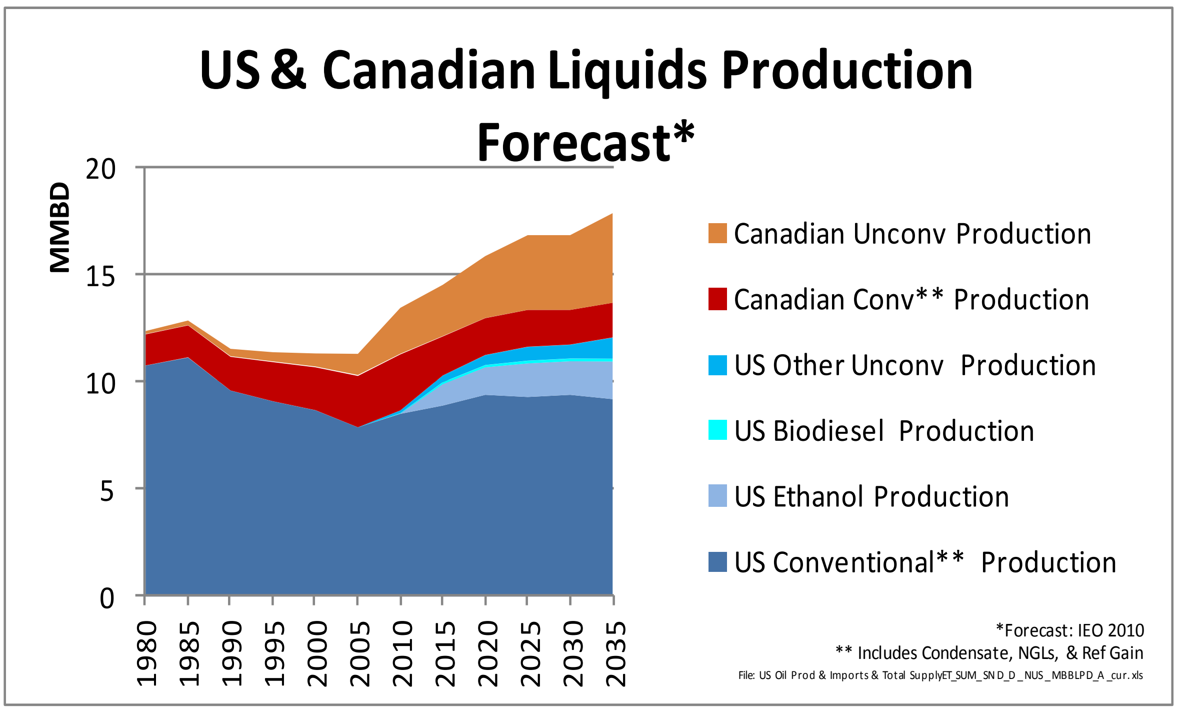


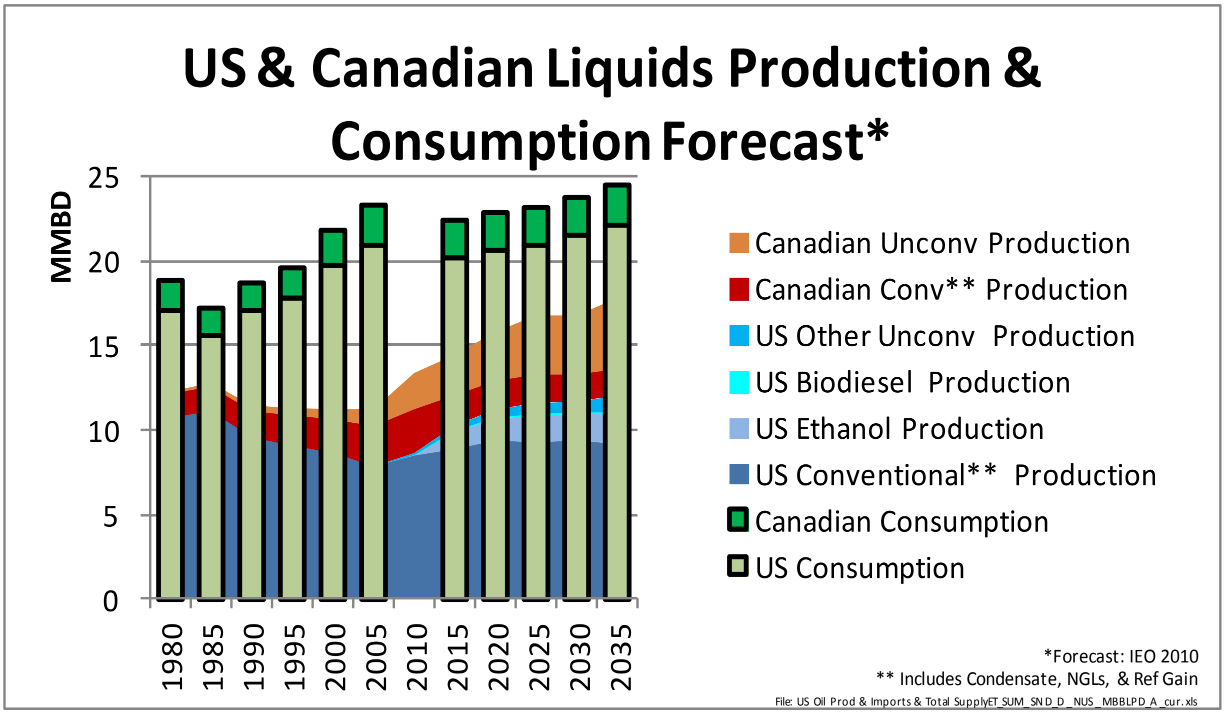
Figure 65: Source – NPC North America Study Database



The EIA's reference case has liquids production rising as a result of not only US and Canadian crude production, but also growth of ethanol, biodiesel and other liquids production (Note in the chart below, conventional oil production includes NGLs and refinery gains). Overlaying the US+Canadian liquids demand from the EIA, provides a picture of the oil imports that will be required if both the EIA's liquids production and consumption forecasts were to come about for some reason. Directionally, liquids imports would drop from about 8 mmbd to 7 mmbd during 2015 to 2035. The IEA current policies and industry reference case would result in a larger import gap. Assuming that Mexico is a net oil importer after 2015, the US oil imports would have to continue coming from outside of North America. Under any of these above scenarios, the US still remains a larger importer of liquids outside of North America, and thus should continue to seek ways to substitute other energy sources for liquids. Gas and electricity can play pivotal role in reducing the dependence on foreign imports and the associated economic, environmental and energy security benefits of increased gas utilization and renewables in the future energy mix.

Figure 66: Source – 2010 EIA IEO





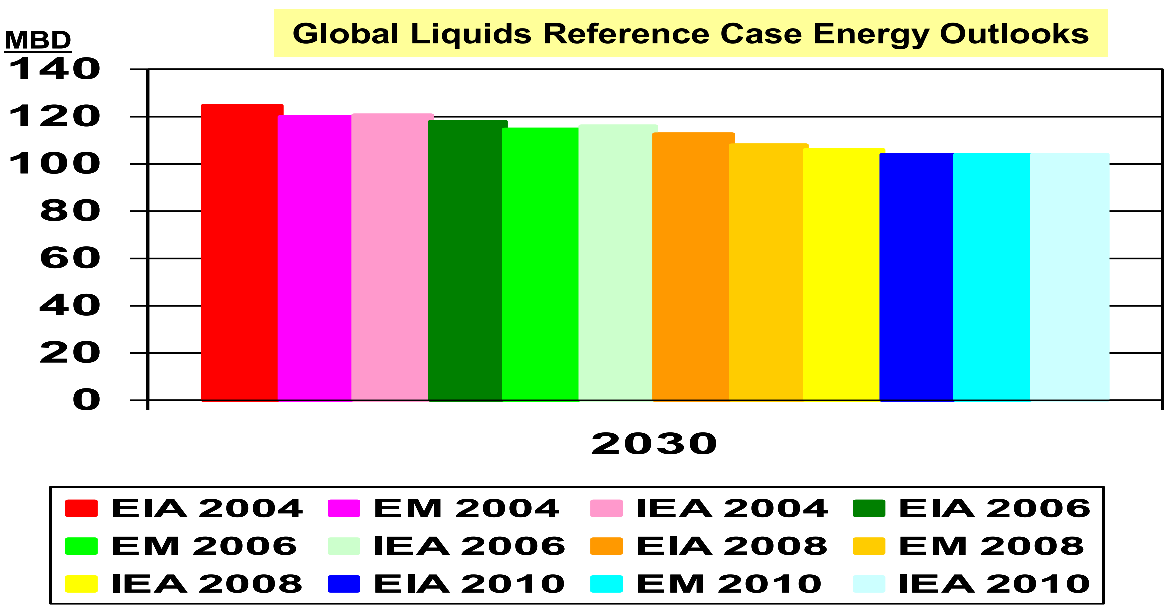
VIII. Appendix A: Global Oil and Gas Outlooks (Context)

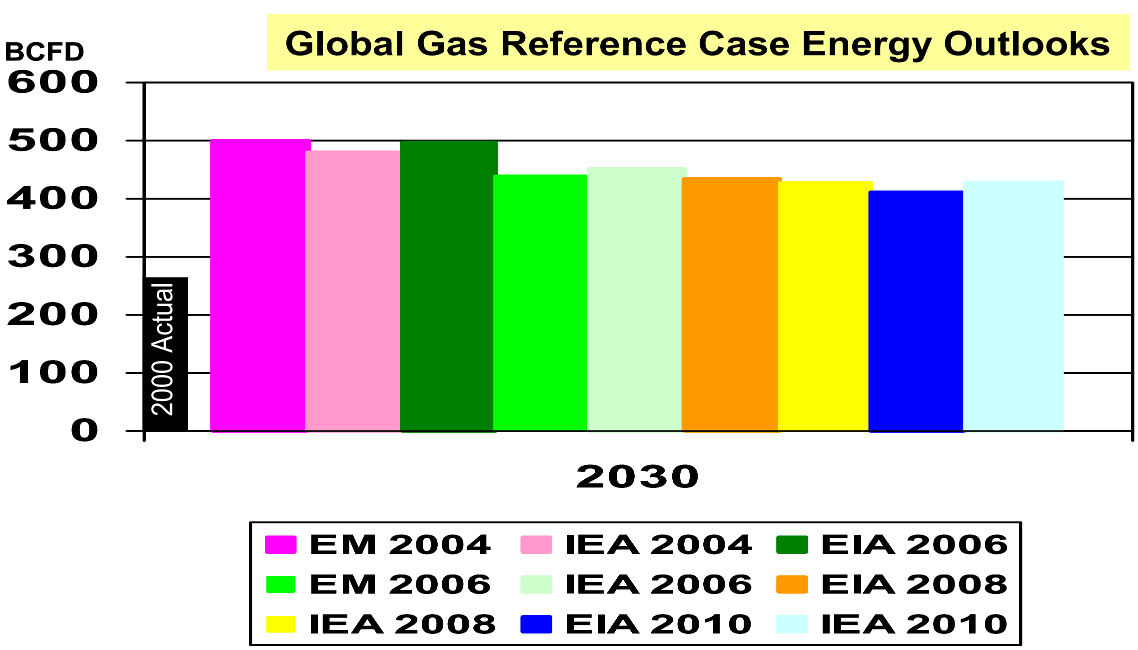
Energy outlooks have changed over time as our technical understanding of the resource base, technology improvements, economic and market fundamentals, and government and regulatory frameworks have evolved along with availability of industry materials and resources to meet energy consumption needs. Each outlook is defined by a set of underlying assumptions. Given the difficulty of modeling all the future uncertainties, it's very unlikely anyone can exactly predict the future. However, these outlooks can provide valuable insights into the key themes, trends and issues that are likely to arise and can also provide a range of possible scenarios we can use to plan for the future.

While we can debate when the annual oil and/or gas production will peak in a reservoir, field, the US, North America or for the World, hydrocarbons are a finite resource that will ultimately decline in production and finally deplete. In the last few decades, there has been growing concern that the size of the US, NA and Global hydrocarbon resource base and the challenges associated with increasing production capacity will limit the role oil and gas will play in meeting the growing local and global energy needs.

Moreover, the heightened outlooks for global economic growth and energy consumption in the last decade suggested even greater demands on the energy sector, which fuels the debate of *supply constrained* as opposed to the *demand driven* energy scenarios for the future. As per the publicly available, global, reference case outlooks from the EIA, IEA and ExxonMobil over the last decade, global oil and gas consumption are anticipated to grow to levels that others groups believed may be unattainable. There are limits to the magnitude and timing of increasing production capacity. While there is no right answer, it is becoming increasingly difficult for production to keep pace with rapid global demand growth.

Figure 67: Source – NPC North America Study Database





While the recent global and North American economic slowdown of the past few years will provide some relief to “challenging” demand growth expectations/needs in the future suggested by the organizations cited above, energy production and consumption remains one of the key issues facing the entire global community. Below are some comments from leading energy executives of the future of global liquids and gas supplies:

- (CEO of Total SA) World oil production will reach a plateau of 95 million barrels a day before 2020, placing a limit on growing energy demand. "We will need a big, big effort" to reach this level.
- (ConocoPhillips Chief Executive) The International Energy Agency, the energy watchdog for western economies, has projected 2030 world oil demand of 116 million barrels a day. However, we don’t believe oil supply will ever exceed 100 million barrels a day. World oil producers will not be able to meet forecast long-term energy demand growth.
- (Boone Pickens) I do believe you have peaked out at 85 million barrels a day globally said during testimony to the Senate Energy and Natural Resources Committee in June, 2008. The US alone has been using “21 of the 85 million and producing about 7 of the 21, so if I could take just a minute on this point, the demand is about 86.4 million barrels a day, and when demand is greater than the supply, the price has to go up until it kills demand”.
- (CERA and Daniel Yergin) The ‘peak oil’ theory causes confusion and can lead to inappropriate actions and turn attention away from the real issues. “Oil is too critical to the global economy to allow fear to replace careful analysis about the very real challenges with delivering liquid fuels to meet the needs of growing economies. This is a very important debate, and as such it deserves a rational and measured discourse. This is the fifth time that the world is said to be running out of oil. Each time - - whether it was ‘gasoline famine” at the end of WWI or the ‘permanent shortage’ of the 1970s – technology and the opening of new frontier areas has banished the specter of decline. There’s no reason t think that technology is finished this time.”
- (Lee Raymond, ExxonMobil CEO in November 2005) After the weak prices in the 1990s due to the oversupply, natural gas production in North America will probably continue to decline unless there is another big discovery. Gas production has peaked in North America, reporters were told at the Reuters Energy Summit. Asked whether production would continue to decline even if two huge arctic gas pipelines projects were built, “I think that’s a fair statement, unless there’s some huge find that nobody has any idea where it would be.”
- (Saudi Aramco Executives) The former head of Saudi Aramco's production and exploration, stated in an October 29, 2007 interview that oil production had likely already reached its peak in 2006, and that assumptions by the IEA and EIA of production increases by OPEC to over 45 MB/day are "quite unrealistic. While, the current Saudi Aramco head says the nonsense of

peak oil is now hopefully behind us and sees no difficulty in getting above 100mb/d.

Former US Energy Security Bodman requested the National Petroleum Council (NPC) study (2006-07 Facing the Hard Truths about *Global* Energy) and provide an update (September 2008) on the following three questions:

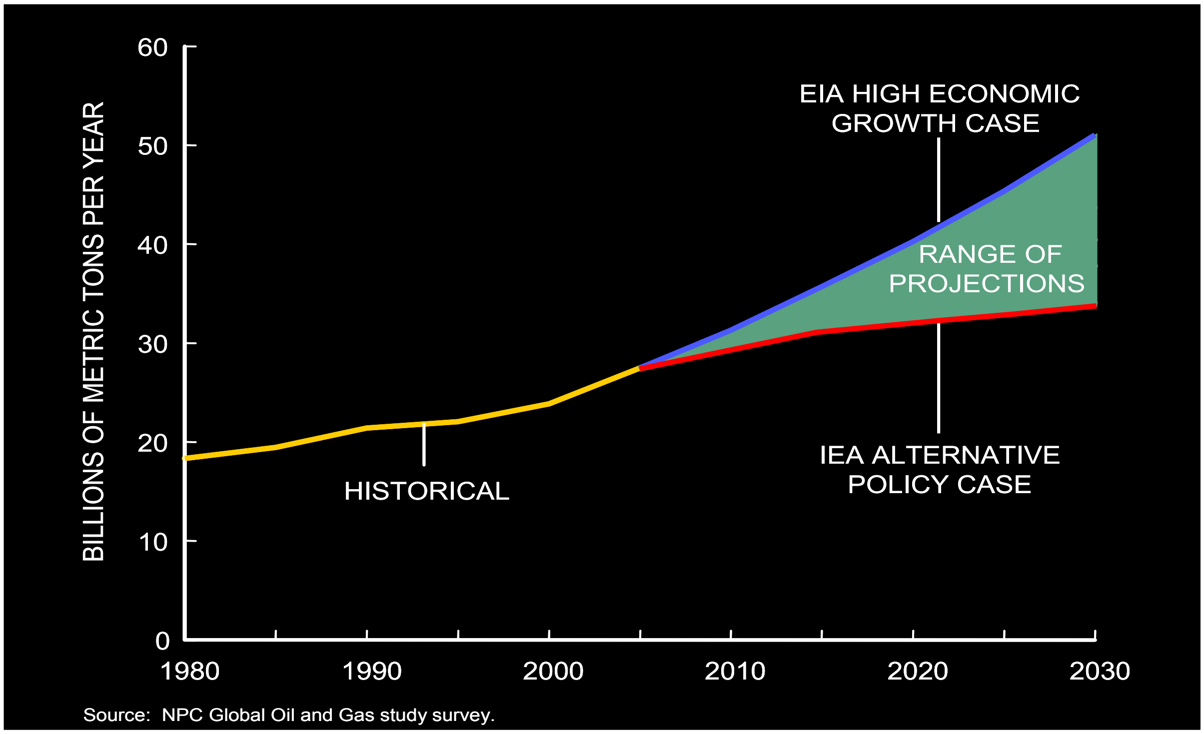
- *What does the future hold for global oil and natural gas supply?*
- *Can incremental oil and gas supplies be brought on-line, one-time, at a reasonable price to meet future demand needs without jeopardizing economic growth?*
- *What oil and gas supply strategies and/or demand-side strategies does the Council recommend the US pursue to ensure greater economic stability and prosperity?*

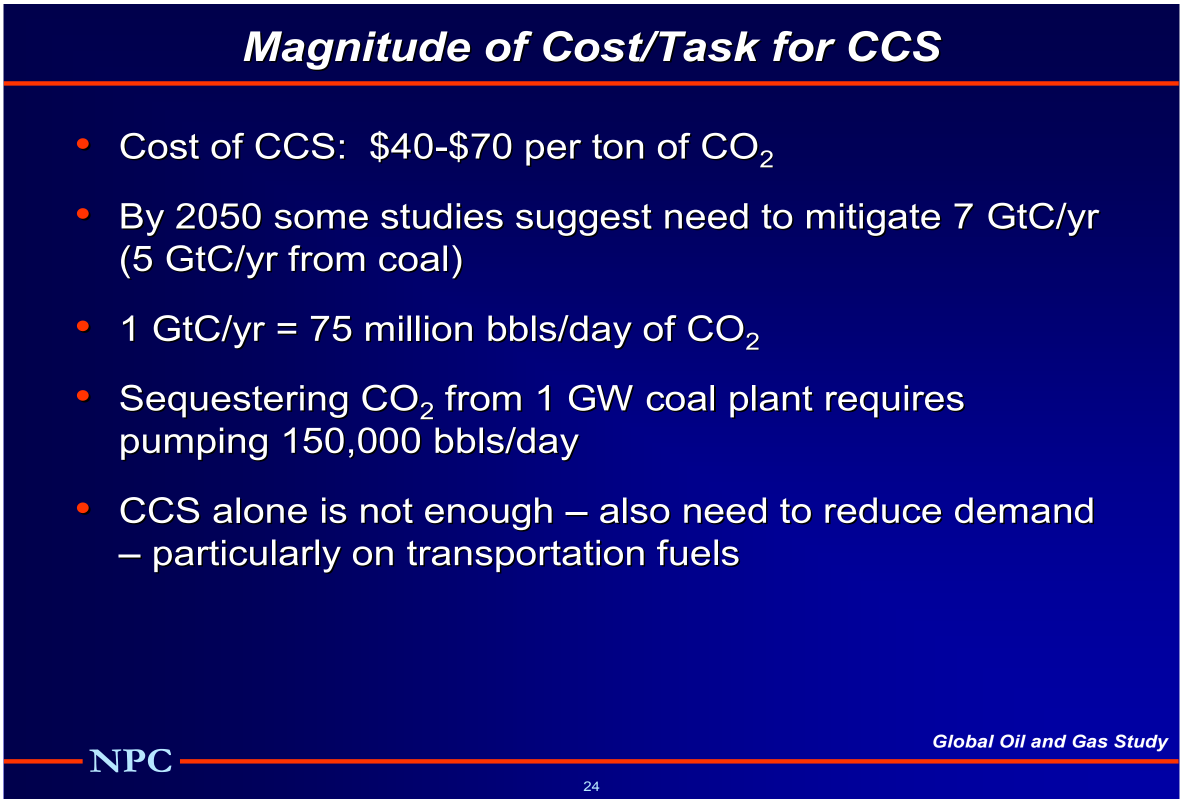
The NPC Hard Truths study stressed that in order for the global demand for fuel and power to be met, all economic energy sources need to be pursued along with increased energy efficiency. While subsequent studies have reported a larger potential oil and gas resource base (primarily unconventional resources), there are increasing risks to conventional supplies and a greater need for unconventional production capacity growth in the future. Examples of increased risks to production growth include 1) the limited increase in supply response despite unprecedented exploration and production expenditures levels in the past few years; 2) increasing cost and delays of major development projects; and 3) forecasts projecting significant increases in unconventional production require continued technology advances and large, new investments. Additionally, the majority of the US energy sector workforce, including skilled scientists and engineers are eligible to retire within the next decade and thus the workforce must be replenished and trained

While gas is the “cleanest” of the fossil fuels, increased renewables and nuclear energy use may have the biggest impact on reducing carbon emissions. Of particular note, is the increased emphasis and importance of addressing energy security and carbon emissions and environmental protection?

While discussions of carbon constraints have intensified, the scale and cost to reduce just a Gigaton of carbon is relatively poorly understood. One estimate of the injection rates of CO2 to remove a Gigaton of carbon is equivalent to a global liquids production rate of 75 million barrels a day. While it has taken over a hundred years to develop the infrastructure, personnel and regulatory systems to achieve the scale and magnitude of oil and gas production levels today, developing a sector dedicated to reducing carbon emissions is an enormous challenge and will require substantial resources, investment and time to develop the scale to make a material difference.

Figure 68: Source – NPC Global Energy Hard Truths Study (2006-07)





Although some progress has been made on demonstrating CCS, there is no existing, comprehensive, legal, regulatory and economic framework. Moreover, although there is considerable interest in increasing CO2 recovery from suitable oil reservoirs and fields both in North America and around the world, one of the biggest challenges is the availability, cost and new possible regulatory obstacles for transport and injection of CO2 oil and associated long term liability issues. While the United States has some naturally occurring CO2 resources that has been historically utilized for CO2 EOR, anthropogenic CO2 will likely be required in the future. Large scale projects and investments are unlikely until many of these uncertainties are addressed.

Likewise, policy uncertainty has also hindered the construction of new US fossil fuel power plants. For example, EPA regulations (such as those affecting traditional pollutants) may affect the extent to which power generators choose natural gas as a fuel source. Emerging EPA regulations on air quality, water use and ash disposal will also likely require existing coal units to choose between installing expensive control equipment and retirement.

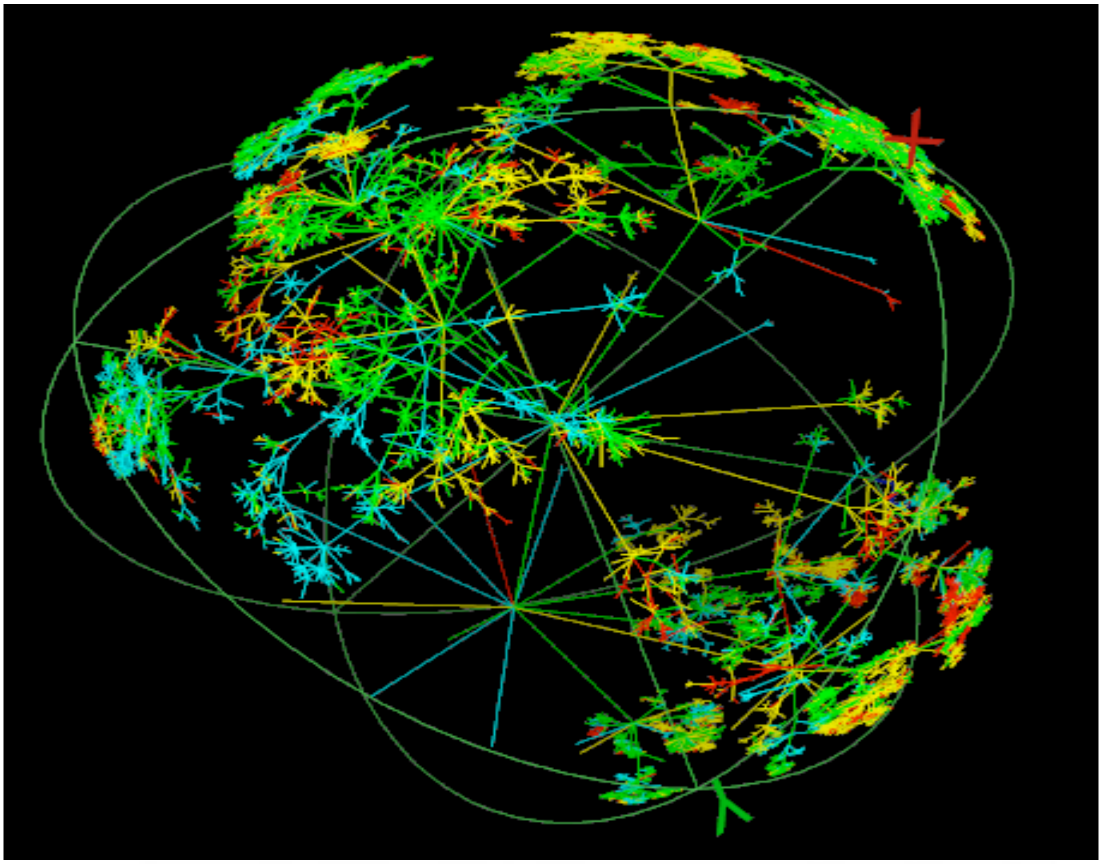
In summary, policies aimed at curbing carbon emissions will likely alter the energy source mix, increase energy related costs, and likely cause reductions in demand growth. While increased use of natural gas may be an inexpensive and fast way to help control CO2 and other emissions, an integrated, comprehensive, in-depth analysis is needed between the interplay of increased natural gas supplies and demand for renewable energy sources.

IX. Appendix A: Global Oil and Gas Outlooks (Context)

Our team was humbled by the depth and breadth of Energy Secretary Chu's request given the complexity of the energy system. While the focus of the study was limited to oil and gas only; clearly coal, nuclear, biofuels, solar, wind, geothermal and other sources will all play a role in the future energy supply and will have to be integrated into US, North American and Global Energy policy decisions. Thus, while we have attempted to understand oil and gas fundamentals and possible impact on the energy system, let us also be mindful of how our findings fit within the context of the possible traits of complex systems:

- Boundaries are difficult to define
- Open
- Non-linear
- Contain feedback loops
- Dynamic network of multiplicity
- Produce emergent phenomena
- Have a memory (e.g., change over time and prior states can have an influence on present and future states)
- Are nested (e.g., an economy is made up of sectors – energy is one, which is made up of organizations, which are made up of people - all of which are complex systems)

Figure 69: Complexity Illustrations



In light of the many integrated parts of the oil, gas and larger energy system, we focused our attention on what we believed are the key future drivers of this system. These included: resource endowment, oil and gas production capacity, infrastructure, macroeconomic, social, environmental and operational and regulatory considerations, and the industry's resources, capabilities and capacity.

We believed the key to comprehension lies in understanding the range of possibilities, likelihood of occurrence, and sustainability of various scenarios within the context of likely stakeholder preferences, activities and reactions of the business environment. We assumed the ultimate goal is to provide reliable, affordable, sustainable, secure and clean energy, fully realizing choices and trade-offs are required to provide the optimum investment climate. Thus, our team's objective was to assess the:

- Size of the Oil and Gas resource base
- "Drivers" to develop and produce the resource base
- Magnitude (and growth rates) of sustainable production capacity
- Levers and Options (Pros and Cons)

Central and paramount to our interpretation was the DATA. The team decided that a wide net of data collection was needed to substantiate any findings and recommendations while addressing potential concerns industry, public and government stakeholders may have about the various strategic options the nation may have. The wide net of public, government and industry aggregated supply data is currently available on the NPC website for the study participants. We recommend that this data is available to the public upon the study completion. Data management and future query capabilities could be potential issues if sufficient resources and time isn't dedicated to capitalize on the value of the data.

Given the complexity of the energy system and the depth and breadth of the collected data, we strived to let the "data speak". We designed a template to collect sufficient data to fully understand the key fundamentals behind institutions' energy outlooks or viewpoints. While we capitalized on some of the same strengths of the Delphic (collaborative) approach during the four workshops we held to discuss the interpretation of the data, we tried to avoid the pitfalls of a committee, group think or advocacy decision making process that is possible if sufficient data isn't available to substantiate findings and recommendations. Moreover, while the EIA and IEA integrated outlooks are valuable data, we also strived to collect as much industry and other public institution data to fully evaluate the spectrum of views and expertise. We were also committed to provide much more than just a commentary of the EIA and IEA outlooks, since we thought this would be of limited utility and believed that Secretary Chu and the DOE had requested the study to augment or compliment the internal data and views they have on the energy sector.

With regard to data robustness, we encountered a wide spectrum of (depth and breadth) responses to our data template/survey request. Very few institutions provided a comprehensive, integrated, US and NA supply outlook, which, in itself, was a significant finding, suggesting there isn't a wealth of well documented, fully integrated, and readily available sources for future oil and gas supply outlooks. For example, 1) many of the outlooks didn't cover all resource types, the full energy value chain or all geographic regions; 2) provide the key underlying assumptions that supported the production outlooks; 3) provide the technical basis for resource estimates; and 4) some estimates were bias to a particular sector or area. **However, the wealth of wide-net data collected from all sources does provide a good interpretation foundation, especially since the evaluation of the consolidated data capitalizes on the strengths and focus areas of all the organizations that supplied data.**

As with many projects and studies, data collection and management is often underestimated and not initiated early enough in the process. This is especially problematic if the data collection and in-depth analysis is constrained given scheduling, stakeholder preferences, etc. We believe that since data is a crucial component of the information, knowledge, understanding and wisdom hierarchy, we recommend for future studies:

1. A dedicated data management leader and team is designated at the beginning of all future National Petroleum Council Studies (especially if multiple task force groups and teams will be requesting public/industry data)
2. All database requirements and data collection needs are identified at the outset to reduce cycle time and provide more time/flexibility for the interpretation phase
3. Integration requirements are defined and resourced at the study outset with greater access to all data to facilitate early integration (e.g. supply, demand, operations, carbon, and macroeconomic, etc elements of this study) to maximize efficiency/effectiveness.
4. Industry aggregation enhancements:
    a. Early identification of any external data aggregations assistance and support to coordinate objectives and integration of all study team requirements
    b. External data experts should participate in all template/survey design to minimize data collection and aggregation time
    c. Templates should be designed for internet utilization to simplify data collection
    d. Increased participation by study task force team members and external data providers in determining aggregation rules – may have enhanced the value and information extracted from data (e.g. IOC, independents and consultant aggregation may have provided greater insights on resource volumes and assessments?).
5. Consider developing a comprehensive, evergreen data warehouse for all past and future NPC studies. This would create a valuable, publicly available data source and, likewise, potentially prevent duplicative historical data collection by future study participants. This would likely require funding and a small, dedicated information management team or, alternatively, could be outsourced to a service provider.