Wood Mackenzie

Douglas Channel Energy Project: LNG & North America Natural Gas Market Assessment (2011 – 2033)

BC LNG Export Licence Application
Schedule E - Wood Mackenzie Report

Prepared for:

LNG Partners, LLC for itself and on behalf of its affiliates BC LNG Export Co-Operative LLC And Douglas Channel Energy Partnership

March 2011

NEB Filing Version

Strictly Private and Confidential

This report has been prepared by Wood Mackenzie for LNG Partners, LLC ("LNG Partners"). The report is intended for the benefit of LNG Partners and affiliates including BC LNG Export Co-Operative LLC ("Export Co-Op") and Douglas Channel Energy Partnership ("DCEP") in support of an export license application to the Canadian National Energy Board and may not be relied upon by any other third party without Wood Mackenzie's prior written consent.

The opinions expressed in this report are those of Wood Mackenzie. They have been arrived at following careful consideration and enquiry but WM does not guarantee their fairness, completeness or accuracy. The opinions, as of this date, are subject to change. WM does not accept any liability for reliance upon them.

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1. Introduction

BC LNG Export Co-Operative LLC(Export Co-Op) is applying to the National Energy Board (NEB) of Canada for a license to export up to 1,800,000 tons per annum of LNG (~90 bcf/year) over the period of 2014 – 2033. Natural gas produced in Western Canada will be transported utilizing existing natural gas pipeline capacity from Pacific Northern Gas Ltd. (PNG), then liquefied at the proposed small-scale natural gas liquefaction facility on the west bank of the Douglas Channel, near Kitimat, BC (the Douglas Channel Energy Project). LNG will then be exported and transported by LNG carriers primarily to key Asia-Pacific demand markets. The initial LNG train of approximately 900,000 tons is expected to commence operations in 2014. LNG Partners has retained Wood Mackenzie, Inc. ("Wood Mackenzie") to provide a written, independent assessment of Canadian and North American natural gas markets and global LNG markets relevant to the proposed Douglas Channel Energy Project and the application of Export Co-Op.

Wood Mackenzie has assessed Canadian and North American gas supply and demand markets, flows, and pricing in this report. Key Asian LNG markets (demand), competing Pacific Basin supply sources, and Pacific Basin LNG pricing are also assessed.

2. Executive Summary

The North American gas markets have made a dramatic reversal since 2008, when prices peaked along with oil. Since that time, the supply picture has gone from a rather dismal outlook for indigenous production, with apparent requirements to import significant volumes of LNG into North America, to a market where natural gas is being evaluated as a potential export product (as LNG) from North America.

The Douglas Channel Energy Project is a proposal to build a Liquefied Natural Gas plant to be located on the west bank of the Douglas Channel, near Kitimat, BC. The Douglas Channel Energy Project will be constructed and owned by entities related to LNG Partners and to the Export Co-Op. Wood Mackenzie has prepared this report as part of the Export Co-Op export license application with the NEB. The report's purpose is to provide fundamental analysis of the North American, and specifically the Canadian natural gas industry, as well as the Pacific Basin LNG markets. This analysis in turn is intended to assist the NEB to assess whether the proposed export will detrimentally affect Canadian gas markets.

The art of extracting natural gas from shale formations was mastered in the past 5 years, after a long 25+ year period of experimentation in the Barnett Shales of Texas. Horizontal drilling techniques, combined with multi-stage hydraulic fracturing have enabled the industry to extract methane from abundant shale formations at a cost well within an expected price range below $7.50/mmbtu (real 2010$ US). The result is North America's gas markets moving from a supply short environment to a demand short environment. Shale gas today comprises 17% of total supply in North America and is forecast to grow rapidly and become the largest component (43%) by 2033. In addition, the technology has been applied to tight gas and oil formations with promising results.

The Western Canadian Sedimentary Basin (WCSB), the most prolific natural gas region in Canada, has been in decline for several years. Gas demand from the production of oil from the heavy oil sands, and gas fired generation in the east, has commensurately been increasing with expectations for continued growth well into the future. The use of shale gas drilling and completion technology in the WCSB and surrounding area is expected to reverse the declines enough to meet growing Canadian demand, and reverse shrinking exports to the US. The Montney, the Horn River, and the Duverney plays in BC and Alberta are expected to help raise WCSB production from 14.4 bcfd in 2010 to 16.6 bcfd by 2033, a reversal of the outlook of only 2 or 3 years ago.

North American natural gas prices are now forecast to be contained below the $7.00/mmbtu (real 2010$) level through 2016 and remain below the $7.50/mmbtu (real 2010$) level through 2033. In contrast, global gas prices are expected to continue to rise along with oil prices. Much of the globe uses oil as the basis for pricing natural gas, and therefore LNG, since oil is a primary alternate energy source. The critical oil price outlook calls for robust pricing into the future as oil demand is expected to continue to outstrip oil production growth, keeping upward pressure on oil prices, between $90/bbl and $100/barrel through this decade, rising above $120/bbl by the 2030s. Utilizing oil price scenarios ranging from $75 - $110/barrel (real 2010$) through 2033 translates to a landed price for LNG in Asian markets between $11.00 - $18.00/mmbtu (real 2010$) through 2033.

Natural gas supply is expected to grow globally, however, it is Wood Mackenzie's perspective today that the magnitude of the shale phenomenon in North America will not be soon replicated. Further, Japan, Taiwan and South Korea (JKT) have very limited, if any, indigenous gas supply. They are nearly 100% dependant on imported LNG. China is also expected to be heavily dependant on LNG to support its natural gas demand growth. Wood Mackenzie is therefore forecasting Pacific Basin LNG demand to increase 3.7% per annum from 17 bcfd in 2010 to 40 bcfd by 2033. Un-contracted LNG demand is expected to grow to more than 14 bcfd across the four largest markets by 2020, providing likely opportunities for new LNG facilities.

Global LNG supply is at a slight surplus today. The story changes quickly as we approach 2016 due to a dearth of new liquefaction projects taking Final Investment Decision (FID) during the 2006 to 2008 timeframe. Approximately 10 bcfd equivalent of new projects went into service in 2009-2010, but only 3 bcfd is scheduled between 2011 – 2013. Additionally, several existing LNG facilities have questionable upstream supply to feed the plants, potentially increasing an impending shortfall in supply. Meanwhile, global demand continues at a growth rate that will potentially create a net global LNG shortage by the 2016/17 timeframe. The global LNG market is comprised of two distinct markets, the Atlantic and Pacific Basins, with the Middle East traditionally serving as the swing supplier. Currently, the Atlantic enjoys a significant LNG surplus while the Pacific market is tightening quickly due to robust regional demand growth that currently is pulling excess Atlantic LNG to satisfy demand. Base case global fundamentals may indicate a balanced market, but actual market realities are creating a supply-demand imbalance in the Pacific which will support Asian LNG contract pricing. The Douglas Channel Energy Project is placed to be one of the contenders to capture a portion of this potential market.

The Douglas Channel Energy Project is not alone in the pursuit of Asian markets. Three US import facilities have announced their intentions to convert to export terminals. Kitimat LNG is also targeting these same markets. Several other projects “on the drawing table” for some time could also come back to life and provide supply competition in the growing Pacific markets. The Douglas Channel Energy Project is well positioned to compete for a portion of the growing demand.

Wood Mackenzie reached the following conclusions relative to the proposed Douglas Channel Energy Project:

- Overall, Canadian gas production is expected to increase above the 2001 peak of 17.5 bcfd by 2025, and will continue increasing slowly to 18.7 bcfd by 2033;

- With a robust view of Canadian supply mid-term, WM believes WCSB production will continue to meet demand in the basin, ultimately outstripping local oilsands-dominated demand growth resulting in increased regional exports of WCSB gas. Natural gas leaving the WCSB is expected to increase from 9.0 bcfd in 2011 to 10.5 bcfd in 2020 before declining to 9.1 bcfd by 2033;

- Natural gas demand in Pacific Rim Markets will account for a disproportionate share of what is anticipated to be a substantial increase in the demand for natural gas over the next 20 years;

- There is a global LNG supply/demand imbalance forecast beginning in 2016/17 and increasing in significance to 2025;

- Within the Pacific Rim, contractual LNG Supply is falling short of demand today, being supplemented with temporarily surplus Atlantic basin cargos through 2016, when new sources of LNG will be required;

- Outside North America where gas prices are linked to the marginal costs of natural gas development; most natural gas prices globally are directly linked to world oil prices. In North America, natural gas prices have become de-linked from oil prices and instead;

- The current differential between global natural gas prices and North American gas prices is sufficient to permit Canadian producers to recover the full opportunity cost of dedicating production to DCEP, DCEP’s cost of transporting and liquefying natural gas, and all other costs to be incurred in Canada to facilitate the exports contemplated in this Application; and

- The spread between North American natural gas prices and world oil prices is forecast to increase over the next 20 years allowing Canadian LNG exports over that period to recover all costs incurred in Canada to facilitate the export.

In summation, the significant potential for otherwise unfilled demand in Pacific Rim markets over the study period should lead to an attractive cost/value spread between North America LNG and markets in Asia and thus provide a unique opportunity for participants in, and beneficiaries of Canada's natural gas industry to obtain added value from LNG exports.

3. North American (US + Canada) & Western Canadian Natural Gas Market Dynamics

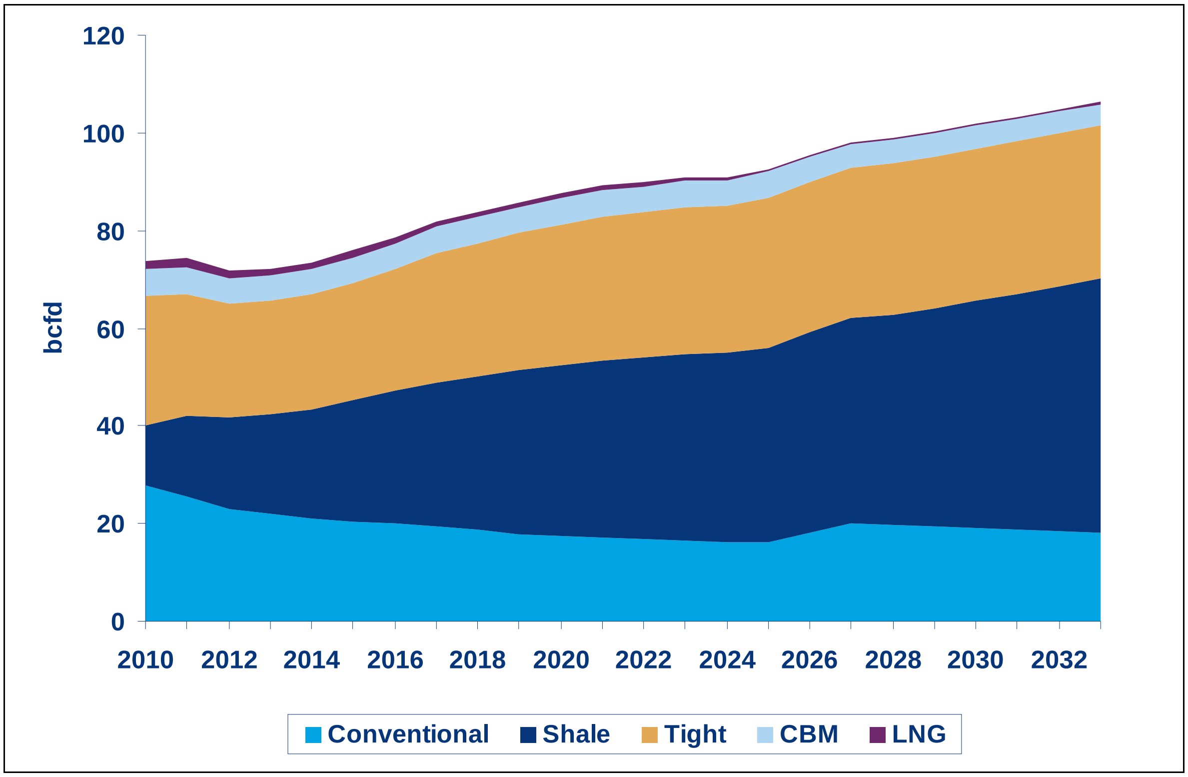
3.1 North American Natural Gas Long-Term View

The North American natural gas markets have undergone a significant change since prices peaked in 2008. Significant volumes of relatively inexpensive gas from the shale plays and a recession of epic proportions have reversed the trend of rising prices and impending shortfalls that had been in place since 2000. Not even a cold 2010 winter, a GDP recovery, a one-in-thirty hot 2010 summer and a cold 2011 winter in succession have been enough to shift the current focus in the NA gas market. Demand for 2010 exceeded 2009 levels by about 2.3 bcfd, yet storage inventories are very close to last year’s levels and the current NYMEX price strip for 2011holds below $4.75. More tellingly, the NYMEX forward curve has flattened significantly during the last year. Not until 2017 does the annual strip reach more than $6/mmbtu—the price many North American producers target as necessary to support continued aggressive drilling programs. In today’s market, shale gas success is overwhelming any demand-side and storage support. Shale gas continues to push production levels up, drilling activity in the shales holds at record highs, and efficiency and productivity improvements across key plays are bolstering production well beyond the levels historically supported by 950 operating gas rigs. But thin margins and an uncertain road ahead cloud the growth story for many producers.

A shift is on the horizon however. Coal retirements, and thereby gas demand growth, will accelerate by 2013-2015, supported by policy initiatives including more stringent sulfur dioxide, nitrous oxide, and mercury emissions standards from the US EPA. This new market pull on supply will intensify, requiring prices to rise enough to incentivize the drilling levels necessary to step up production growth, increase upstream returns and attract investment opportunities away from the very best shales. The lowest-cost core and tier-one areas will no longer prove sufficient to balance market needs. Those next-best shale gas projects will face upgraded competition for capital from tight oil and liquids-rich plays. The call on horizontal gas rigs, completion services, and labor from both shale gas and tight oil projects will keep some upward pressure on costs. A Henry Hub annual average price in the $6.50-$7.00/mmbtu range—well above today’s NYMEX strip—still appears necessary, and likely in the mid term, especially post 2015.

Oil is a key variable in this story. When shale success in North America first opened a wide gap between gas and oil prices, investment options designed to bridge the price gap focused primarily on the demand side. Given persistent wide spreads, natural gas vehicles and a rebound in petrochemicals both emerged as renewed market opportunities. Perceived maturity of US oil resources meant that even in an $80/bbl oil world, upstream capital would continue to target lower-priced gas. Now that the Bakken shale play in Saskatchewan, North Dakota, and Montana has proven that technology used in the shale gas’ success can be translated to oil, supply-side competition for capital, which is increasing as tight oil and oil shale plays offer superior returns and opportunity than the gas equivalent. A 10% internal rate of return may no longer be sufficient to attract investment in gas plays, and cost pressures in an expanding industry are expected to increase the price levels necessary to achieve a 15% internal rate of return. In this context, we forecast North American gas supply growing 1.7% per annum from 73 bcfd in 2010 to 108 bcfd in 2033 (see Figure 1). Shale supply is expected to comprise about 45% of total gas supply by 2033 (vs. 17% in 2010).

Figure 1. Wood Mackenzie US + Canada Natural Gas Supply by Type



Source: Wood Mackenzie

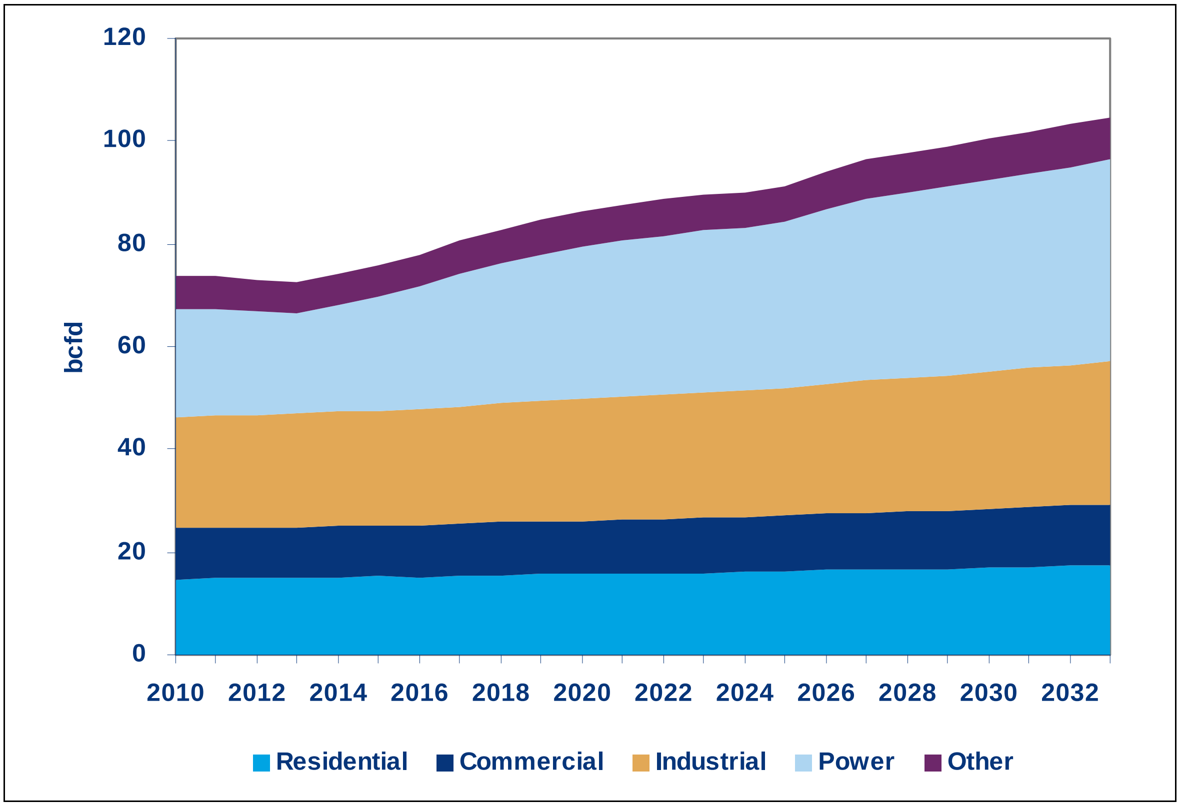
Other cost pressures will also impact the price of natural gas. Higher coal mining costs due to tighter environmental controls will push the floor price for gas up in the mid term. Increased mining costs suggest contract prices for Central Appalachia (CAPP) coal—gas' main competitor in the mid-Atlantic power markets—will increase to the mid- to upper-$60/ton range by 2015. This is much higher than the 2009 low $50/ton average contract price, a difference of about $0.90/mmbtu in gas-equivalent terms. Starting in 2016, we expect a carbon tax in the US to effectively add an additional $1/mmbtu to the price of coal relative to gas.

Tighter environmental standards and costs, as well as increased regulatory costs within the gas industry also appear more likely now than in the past. The blow out in the Macondo well in the Gulf of Mexico was finally sealed in mid-September 2010, but concerns have now been raised that will impact the drilling industry for years to come. That disaster, along with well blowouts and water handling and contamination incidents in the Marcellus shale, are expected to give rise to increased scrutiny and tighter standards that will add to production costs over the next decade. The Marcellus gas play has already seen proposals from the Pennsylvania Department of Environmental Protection for tighter casing and cementing standards and they now require testing of blowout prevention equipment after installation and before use. Further downstream, the PG&E pipeline explosion in San Bruno, Calif. will likely result in an additional layer of scrutiny on the natural gas transport and distribution side of the business.

The ultimate size of the gas market over the next 20 years will be defined not only by operators' success in developing the vast resources now accessible in the shales, but also by two additional key drivers: policy on a national and state/province level, and the development of the US and Canadian oil opportunity. On the policy side, initiatives from the US EPA, state clean air goals, and within the Wood Mackenzie Long-Term View, a modest price on carbon emissions in the US starting in 2016 all give gas a long-term advantage over existing coal plants.

Even without a US carbon tax, significant coal fired generation retirements are likely, and gas-fired generation will fill the gap. However, clean air initiatives could fade if the US economy falters and changes in Washington usher in a different set of priorities. Without policy support, gas cannot supplant nearly as much coal as expected. However, with the policies we foresee being in place, Wood Mackenzie expects the North American gas market to grow 1.5% per annum to reach 105 bcfd by 2033 (see Figure 2).

Figure 2. Wood Mackenzie US + Canada Natural Gas Demand By Sector



Source: Wood Mackenzie

3.2 Canadian Natural Gas Supply: 2011 – 2033

Wood Mackenzie's long-term expectation for Canadian natural gas production has increased from forecasts developed several years ago. Conventional production declines in the mature Western Canadian Sedimentary Basin (WCSB) were expected to be so strong that exports to the US were then forecast to decline rapidly. Recent technological improvements, however, have enabled the economic development of what were previously considered uneconomic resources, creating a paradigm shift in expectations:

WCSB Supply Trends:

- **Montney.** Initial development in the burgeoning Montney tight gas and shale plays show optimistic results, with 2010 Montney production coming in stronger than expected. Wood Mackenzie forecasts production increasing from 0.6 bcfd in 2010 to 4 bcfd by 2033.

- **Horn River** is expected to be a game changer for the WCSB region. Production is forecast to grow gradually during the next few years and reach more than 1 bcfd by 2015. Infrastructure developments to help bring the newer plays on-stream continue and are expected to prevent pipeline bottlenecks, as some new pipes and already well-developed Alberta infrastructure are anticipated to handle the onset of initial

- new production. Wood Mackenzie forecasts production increasing from 0.2 bcfd in 2010 to 4.6 bcfd by 2033.

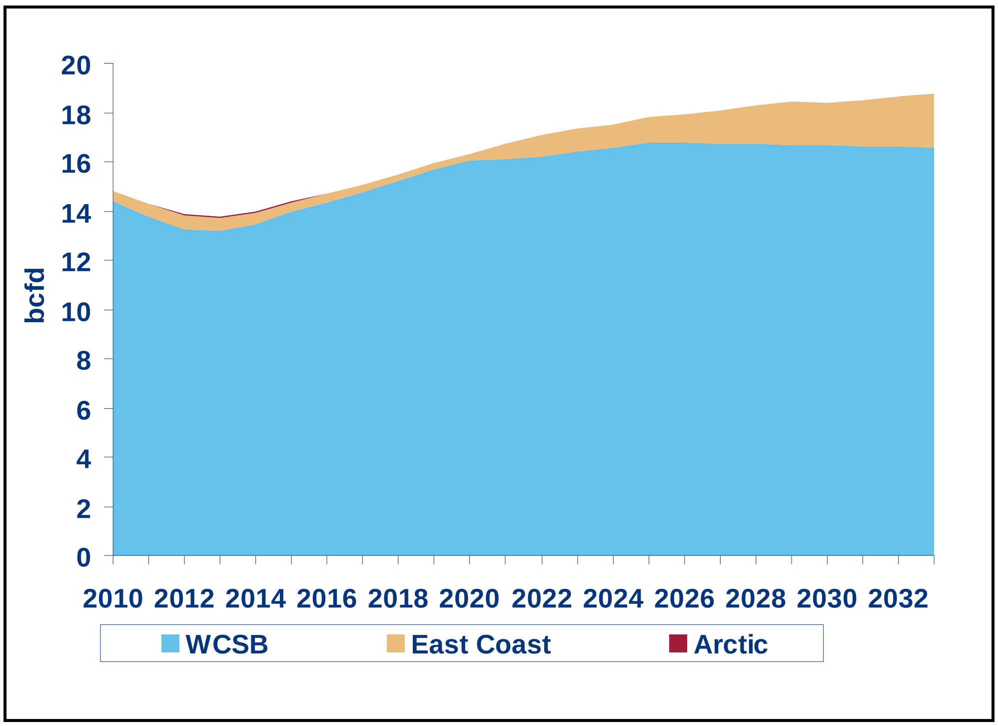
- **Alberta shales**. Sentiment also has improved east of the BC-Alberta border, as an adjusted Alberta royalty framework and excitement over resources within the Alberta Foothills region has brought renewed interest in the Alberta natural gas industry. As a result, the outlook for Alberta shales has improved, especially for the Eastern Montney and Duverney plays. Both plays have good resource availability as well as access to proximate infrastructure.

Eastern Canadian Supply Trends:

- The Deep Panuke in **Eastern Canada**, a Maritimes Canada offshore play, remains in the development queue for 2012, with Utica shale production in Quebec starting to enter the mix in late 2020. The more costly Utica shale remains on the higher end of the North American cost curve, so its development lags behind many of the continent's other plays, both conventional and unconventional. Utica development drives growth in Eastern Canadian production by 2020, as Maritimes volumes gradually decline following the onset of Deep Panuke in the mid-term.

Our outlook for WCSB production increases from 14.4 bcfd in 2010 to 16.6 bcfd in 2033. Overall, Canadian gas production is expected to actually increase above the 2001 peak of 17.5 bcfd by 2025. Production will continue increasing slowly to 18.7 bcfd by 2033 (see Figure 3). Short- and mid-term growth will be driven by Horn River, Montney, and Duvernay shale and tight gas developments, while longer-term, Deep Panuke and Utica gas support growth.

Figure 3. Wood Mackenzie Canada Natural Gas Production Forecast

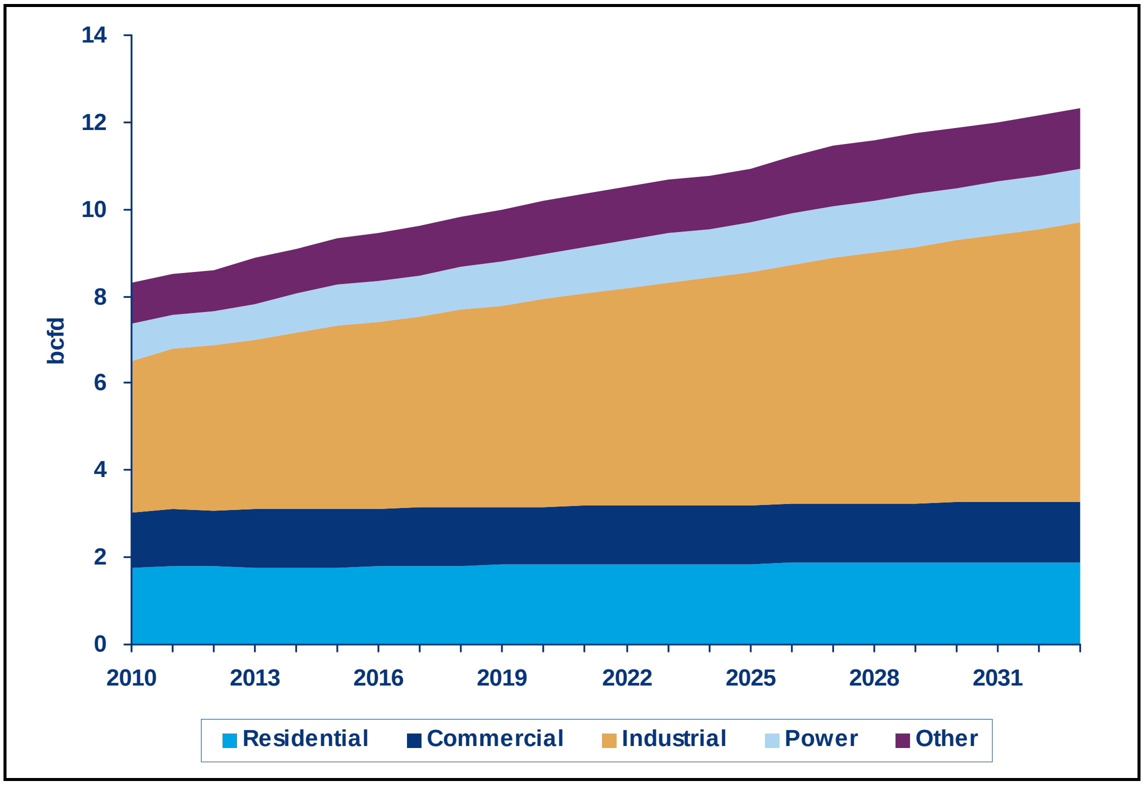


Source: Wood Mackenzie

3.3 Canadian Natural Gas Demand: 2011 – 2033

Canadian natural gas demand continues to grow, mostly driven by the increasing call on gas for expanding oil sands development. Wood Mackenzie forecasts Canadian natural gas demand to increase from 8.3 bcfd in 2010 to 12.3 bcfd in 2033, a rate of 1.7% per annum.

Figure 4. Wood Mackenzie Canadian Natural Gas Demand Forecast By Sector



Source: Wood Mackenzie

Canadian Industrial Sector Demand Outlook

Oil prices rebounded in 2010 following the whipsaw experience of 2008-2009. Market expectations for oil sands development have also rebounded along with prices. This is not to say that many challenges facing the unconventional resource base have disappeared, but the bottom-line support for the proliferation of oil sands development—strong potential profit margins—has re-emerged. Despite oscillations in oil prices and expectations over the last several years, long-term fundamental drivers and their implication on development of the vast unconventional resource base have greatly improved.

This long-term oil sands outlook, though, also contains several risks that are detailed below:

Oil Sands Support

• High oil prices. After bottoming out in February 2009, oil prices have now recovered to the $80 - $90/bbl range, which should continue until the end of 2012 before moving above $90/bbl.

• Narrow bitumen-WTI differential. Declining heavy oil production from places like Mexico and Venezuela and adequate complex refining capacity in the US has supported a narrowing of the heavy-to-light differential. Recent oil pipeline disruptions widened the spread at times in 2010, but narrow differentials will continue to support economics of un-integrated oil sands projects.

• Diversification of customers. Foreign investment, particularly by Asian corporations, is gaining traction in the Canadian energy world. This could provide some support for consumer diversification of Canada's expanding resource development. Enbridge is currently proposing the Northern Gateway Project, which includes a pipeline to move petroleum from the Edmonton area to the Kitimat marine terminal on the British Columbia coast. An application is currently before the Canadian National Energy Board.

Oil Sands Risk

• Environmental concerns. While some sort of climate change regulation is likely, the US, Canada, and especially Alberta will be very careful not to introduce a program that will prove particularly detrimental to oil sands development. As the oil sands become an increasingly important revenue generator for both the provincial and federal governments, we expect governments to explore environmental regulations emphasizing responsible development that do not come at the cost of economic growth.

• Shale oil shift. First it was shale gas, and now it looks to be shale oil. The Bakken play in Saskatchewan and the US states to the south is of particular interest from the Canadian perspective. The play has emerged as North America's leading light oil producer, with breakevens of less than $35/bbl. Many unknowns remain. Related to the development of this play in southern Saskatchewan, Wood Mackenzie sees tightening of oil fundamentals between now and 2015 as supportive of its development, along with other WCSB light oil plays such as the Cardium and Viking. The well breakevens associated with these, and other, shale oil plays are significantly more competitive than the breakevens for the oil sands projects, and associated increased development could impact long-term oil sands investment (and therefore natural gas demand in Canada).

• Project high-grading. With more proposed projects than will be developed, we expect the most economic, or easiest access, projects to be developed first. Steam assisted gravity drainage (SAGD) oil sands projects in particular have been delivering lower volumes than expected, helping lend favor to mining projects. Looking forward, greenfield projects look particularly challenged as players seek out measured growth opportunities with the least potential risk following economic and financial market turmoil.

• Decreased gas utilization. Natural gas is an important input into oil sands projects, both in extraction and refining, and a move toward the least gas-intensive types of projects, or increases in efficiency, could mean further reduction in overall gas demand in oil production.

With the US still making up the dominant share of the Canadian export market, long-term core industrial performance will hinge significantly on the economic health of the US. Core industrial demand should increase gradually through 2033, as low North American gas prices, and a much more optimistic WCSB production expectation, help support domestic industrial activity. An Alaskan pipeline is also forecast to come on-stream in 2026, putting downward pressure on both Henry Hub and Western Canadian gas prices. Completion of the pipeline is expected to help industries in Alberta.

A risk to Canada's long-term core industrial, and for that matter oil sands outlook is the potential for Canada to be priced out of the US and global markets by lower-cost oil exporters. This is much more likely if oil consumption growth decelerates. However, we continue to see good support for a continuation of the existing strong trade. Our outlook assumes the US remains Canada's dominant demand market for exports.

Aggregate industrial gas demand, which includes both core industrial and oil sands demand, is forecast to increase from 3.5 bcfd in 2010 to 6.4 bcfd by 2033, driven predominantly by continued oil sands development. Of the 6.4 bcfd in 2033, oil sands demand accounts for 3.7 bcfd.

Canadian Power Sector Demand Outlook

Wood Mackenzie expects natural gas' share of total Canadian generation to decline in the short term. Estimated to be 7.7% of the 2010 generation mix, gas will decline to a low of 6.9% in 2014 before regaining some traction due to the mandated Ontario coal plant retirements. Ontario's mandate for the retirement of all four of its coal generation before 2015 remains the driving force behind the forecast growth in Canadian gas demand for power. A significant portion of the more than 6,400 MW is slated to come off by the end of 2010. The lost coal capacity will be offset by increases in wind, biomass, nuclear, and gas combined-cycle capacity.

Gas also accounts for a significant share of power generation in Alberta, but unlike Ontario, gas generation is expected to remain relatively flat through the long term in the western province. Power demand growth is anticipated to be met with wind and other renewable capacity, as well as the province's first nuclear plant, planned for in-service in 2029. Coal is expected to remain king in Alberta. Programs in support of clean coal technologies are heavily supported in the region. Any environmental policy aimed at reducing coal generation in Canada would however impact Alberta more than other province, having an impact on forecast gas demand in the province.

Canada's gas demand for power is expected to increase from 0.8 bcfd in 2010 to 1.2 bcfd in 2033. Growth is expected to be greatest post-2015, given Ontario's mandated coal retirements and the associated transition toward gas-fired generation.

The reliability, efficiency, and relatively short build time of gas generation could translate into potential upside for natural gas demand if delays or reliability concerns surrounding other power sources materialize, if extreme weather pushes higher utilization, or if federal emissions policy currently being discussed were to be implemented. Downside influences will most likely come from stronger efficiency gains. Wood Mackenzie includes modest conservation improvements and efficiency gains in the forecast, but efficiency programs being pursued by both provincial and federal governments and individual consumers mean that a long-term transition in consumer usage could make a material difference to our power load forecast.

Canadian Residential and Commercial Sector Demand Outlook

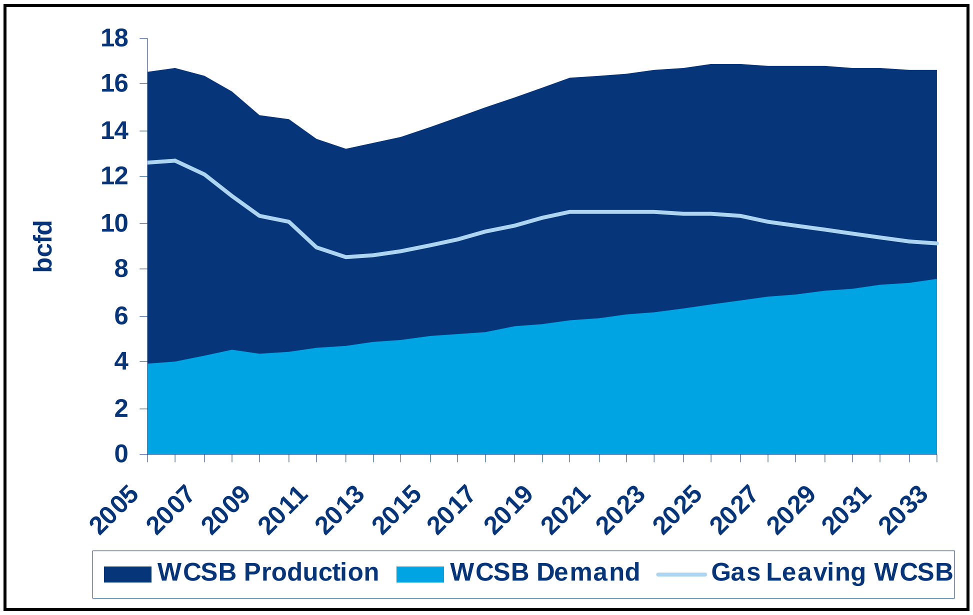
Wood Mackenzie expects residential and commercial demand to grow a modest 0.3% per annum from 3.0 bcfd in 2010 to 3.3 bcfd in 2033, Customer additions will slightly outweigh efficiency improvements. Wood Mackenzie has accounted for mild growth in natural gas vehicles within Canada's commercial demand segment in this long-term outlook. The strength of North America's resource potential and the forecast sustained disconnect between oil and gas prices support expanded natural gas use as a transportation fuel, but the sector remains relatively small; by 2033 demand from NGVs is still less than 100 mmcfd.

Canadian Exports & WCSB Supply-Demand Balance

Canada's net natural gas exports to the US are expected to decline until 2014. Post-2014, when flows are expected to bottom out at around 5 bcfd, exports should start to increase modestly toward a 2025 peak of about 7 bcfd, along with strengthening WCSB production. Net exports should stabilize in the 6.5 bcfd range through 2033 and beyond.

With a robust view of Canadian supply mid-term, Wood Mackenzie believes WCSB gas will ultimately outstrip local oil sands-dominated demand growth resulting in increased regional exports of WCSB gas. Natural gas leaving the WCSB is expected to increase from 9.0 bcfd in 2011 to 10.5 bcfd in 2020 before declining to 9.1 bcfd by 2033.

Figure 5. Wood Mackenzie WCSB Balance



Source: Wood Mackenzie

Wood Mackenzie also expects Canadian gas flows to shift over the forecast period. WCSB gas will target eastern Canada, primarily Ontario, but the Western and Midwestern US will continue to be a key outlet for most exported Canadian gas. WCSB production will continue to meet demand in the basin, exporting gas to the east and west after meeting local needs. Flows out of the region will occur first on the least expensive pipelines, using the TCPL Mainline only as needed due to the current very high costs of transportation on the system. The ultimate effect is that when incremental volumes of gas need to leave the basin via TCPL's Mainline beyond those required to meet firm requirements in the East, AECO prices must decline to the extent that WCSB gas can compete with less expensive sources of gas in the market area, primarily US shale gas production. This will have a negative impact on gas value in the WCSB at these times, especially during the non-heating seasons and as gas production in the basin increases.

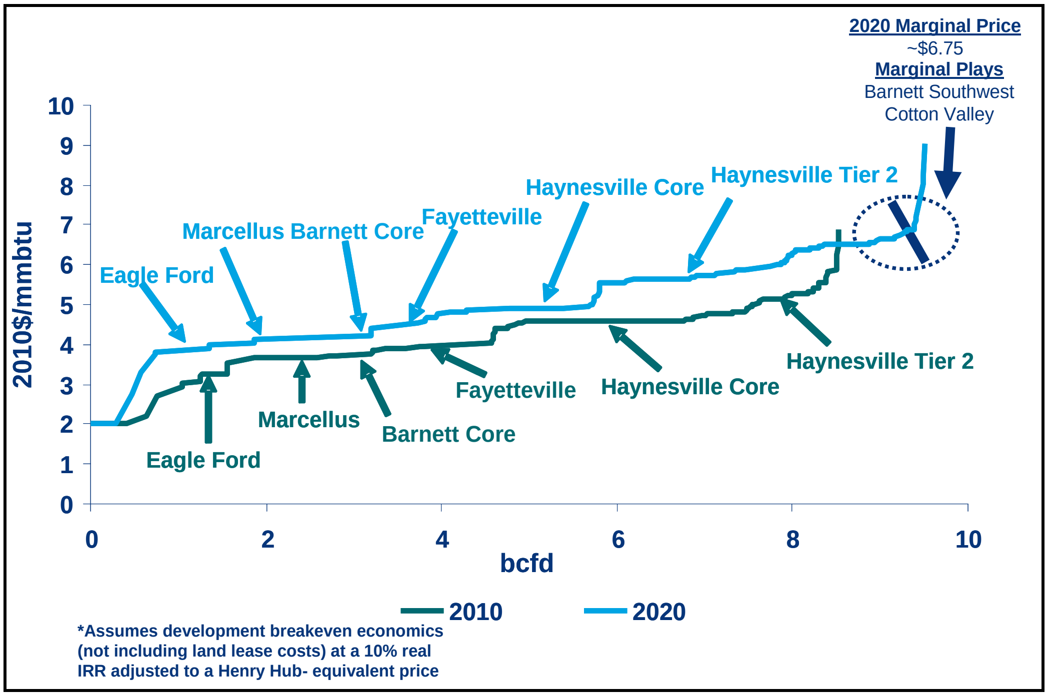
Wood Mackenzie believes, in light of all the above discussion, that exports from the proposed Douglas Channel Energy Project of up to 0.25 bcfd would not materially impact WCSB natural gas market dynamics due to the small scale of the project. If there is any measurable impact, the project may be slightly supportive to gas prices in the region.

3.4 North American Natural Gas Pricing: 2011 – 2033 (prices in real 2010 USD)

2011 – 2020 Price Outlook

Wood Mackenzie believes that low-cost shale gas alone is not likely to meet the entirety of new gas market requirements. The North American gas resource base is more than adequate to deliver the 14 bcfd of supply growth necessary to serve the changing North American demand market by 2020, even at price levels in the $6/mmbtu range. However, Wood Mackenzie expects constraints that developed around availability of pressure pumping equipment in 2010 will likely emerge in different parts of the upstream value chain in the future. Inexperienced new crews, rig availability, or services constraints more generally are likely to push costs up during any sustained growth period, as both oil and gas investment accelerates. Our view of new drill natural gas development economics (at 10% IRR, exclusive of land and lease costs) reflects increasing costs. Marginal plays reflecting our 2015 - 2020 Henry Hub price expectation of $6.50 – $7.00/mmbtu (see Figure 6 below). Marginal plays are expected to include the Cotton Valley tight gas and the emerging Barnett Southwest shale.

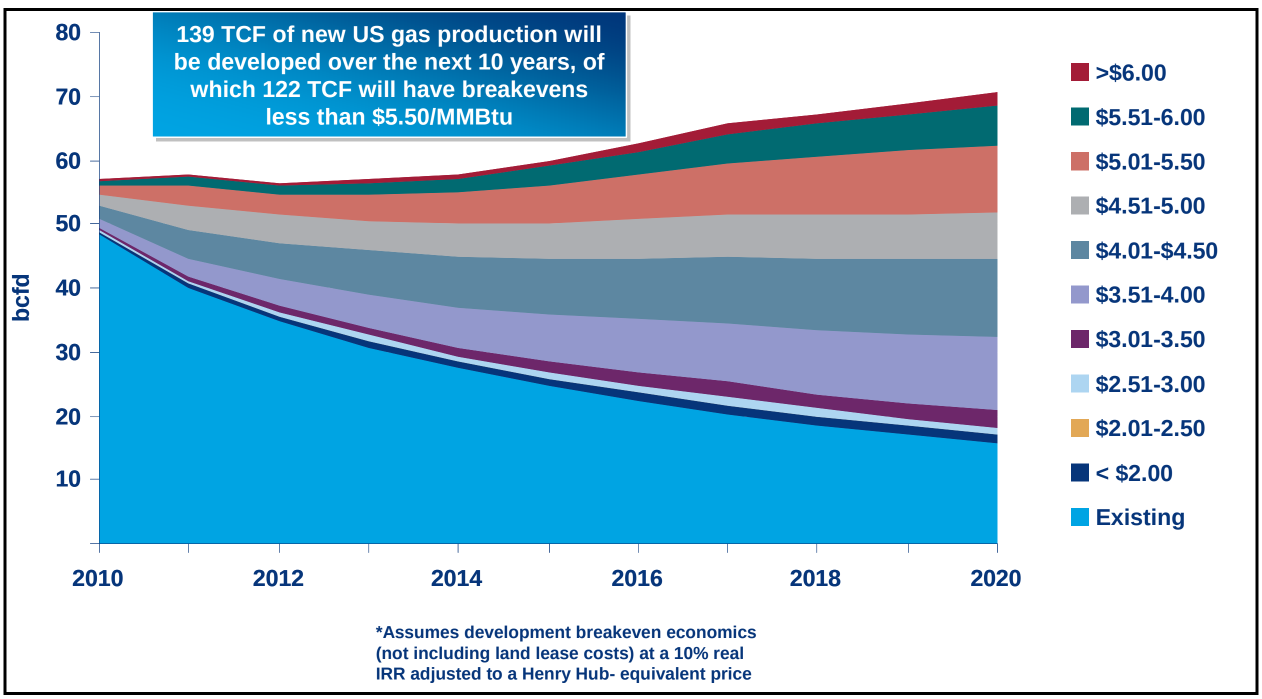
Figure 6. US New Drill Natural Gas Supply Stack*



Source: Wood Mackenzie

Despite the need to drill more expensive conventional and tight gas longer-term, 90% of incremental North American gas production through 2020 will be developed at economic breakevens under $5.50/mmbtu (see Figure 7). We expect Henry Hub to average $6.50/mmbtu through 2020, however, downside risk could potentially pull prices down to $5.00 - $5.50/mmbtu driven by uncertainties around GDP growth and US carbon policy.

Figure 7. US Natural Gas Production & Development Breakeven Economics



Source: Wood Mackenzie

2020 – 2033 Price Outlook

Beyond 2020, gas market size continues to grow at a steady pace. Wood Mackenzie's expectations are that carbon prices will rise, raising the floor for North American gas prices by switching some generation dispatch away from coal and towards natural gas. Prices will not be high enough to cover the costs of additional investment in efficiency or zero-carbon technologies. Global gas prices move higher than $10/mmbtu by 2023, and oil prices rise to more than $100/bbl in 2025, so transport and industrial opportunities for natural gas will continue.

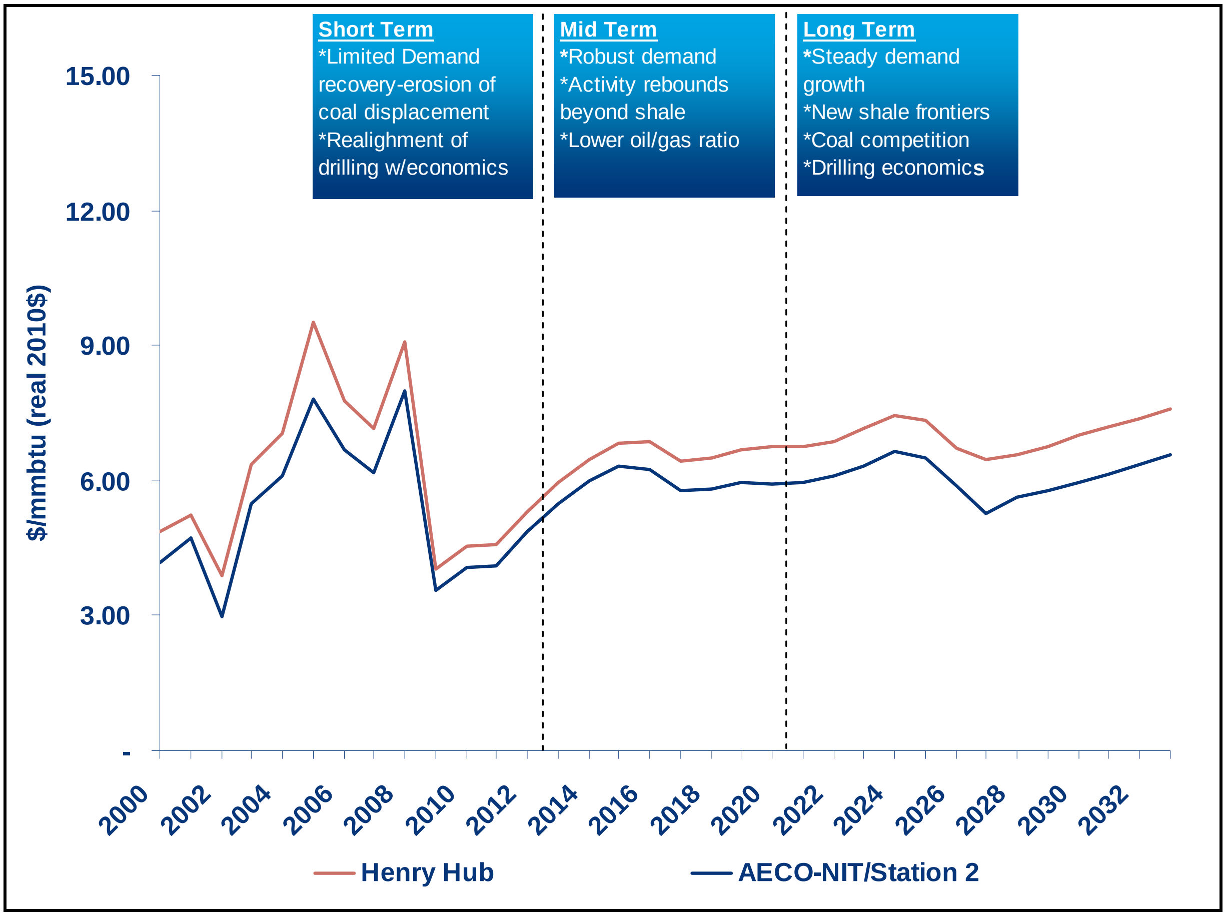
Developing supply growth to meet growing demand becomes more costly late in the study period, although prices are not expected to rise beyond the low to mid-$7.00. With vast low-cost resources in place, Horn River, Montney, Marcellus and Haynesville production continue to climb, but at a much slower rate relative to the previous decade. The Eagle Ford, Barnett, Woodford, and Fayetteville shales, however, with limited resources in place, means flattening production levels. Continued investment in higher-cost tight and conventional plays in the Gulf Coast and Rockies regions add new supply but require a price signal in the mid- to upper-$6/mmbtu range to be developed.

Wood Mackenzie believes that higher prices will also begin to draw in another wave of higher-cost, more technically challenging shales. These resources, while more costly to develop, do not require significantly higher investments to produce enough supply to meet demand. New volumes from the Utica shales, West Texas Permian shales, Southeast shales, and Rockies shales all hit the market after 2020 in our forecast. Some level of development is already underway in these plays, but this set of plays generally features higher breakeven costs or other development challenges relative to the current slate of supplies.

Although prices climb with continued strong activity levels, and new higher-cost supplies compete into the market, several factors contain any severe upward pressure on prices:

- The "higher costs" are not that much higher. Significant volumes of gas can be brought to market at prices in the $7.00 – 7.50.
- Alaskan supplies. Although successful Lower-48 shale development has called into question the ultimate need for this project, Wood Mackenzie's view is based on project economics, which are competitive with other potential supply sources late in the study period. With tariffs estimated at about $2.75-$3.00/mmbtu to Alberta, Alaskan gas enters the competitive supply mix at a price in the $5/mmbtu range, below many other incremental supplies. The assumed 2026 online date for the project is in recognition of major hurdles this massive project faces.
- Slower power sector gas demand growth. From 2020-33, gas demand in the power sector grows by about 700 mmcfd annually, less than the 900 mmcfd annual pace of growth between 2010 and 2020 and well short of the rapid run in demand as coal plants retire en masse between 2013 and 2020.

Figure 8. Wood Mackenzie Long-Term Henry Hub & AECO-NIT/Station 2 Gas Price Outlook



Source: Wood Mackenzie, Energy Velocity

More WCSB gas will find its way into eastern Canada, along with the eastern, Midwest, and western US markets. Important to note, however, is the push rather than pull reason for this forecast, the implication of which is largely illustrated in the current AECO-NIT/Station 2 basis forecast. AECO-NIT/Station 2 basis has averaged $0.90/mmbtu below the Henry Hub over the last decade. Discounts have tightened somewhat, but the negative relationship to Henry Hub should continue. AECO-NIT/Station 2 basis to Henry Hub falls from a $0.45 forecast discount in 2011 to a $0.82/mmbtu discount by 2020 reflecting additional supply growth and evacuation requirements. Longer-term, Wood Mackenzie forecasts the discount to Henry Hub growing to $0.90 - $1.20/mmbtu after the arrival of Alaskan gas in 2026 (see Figure 8)

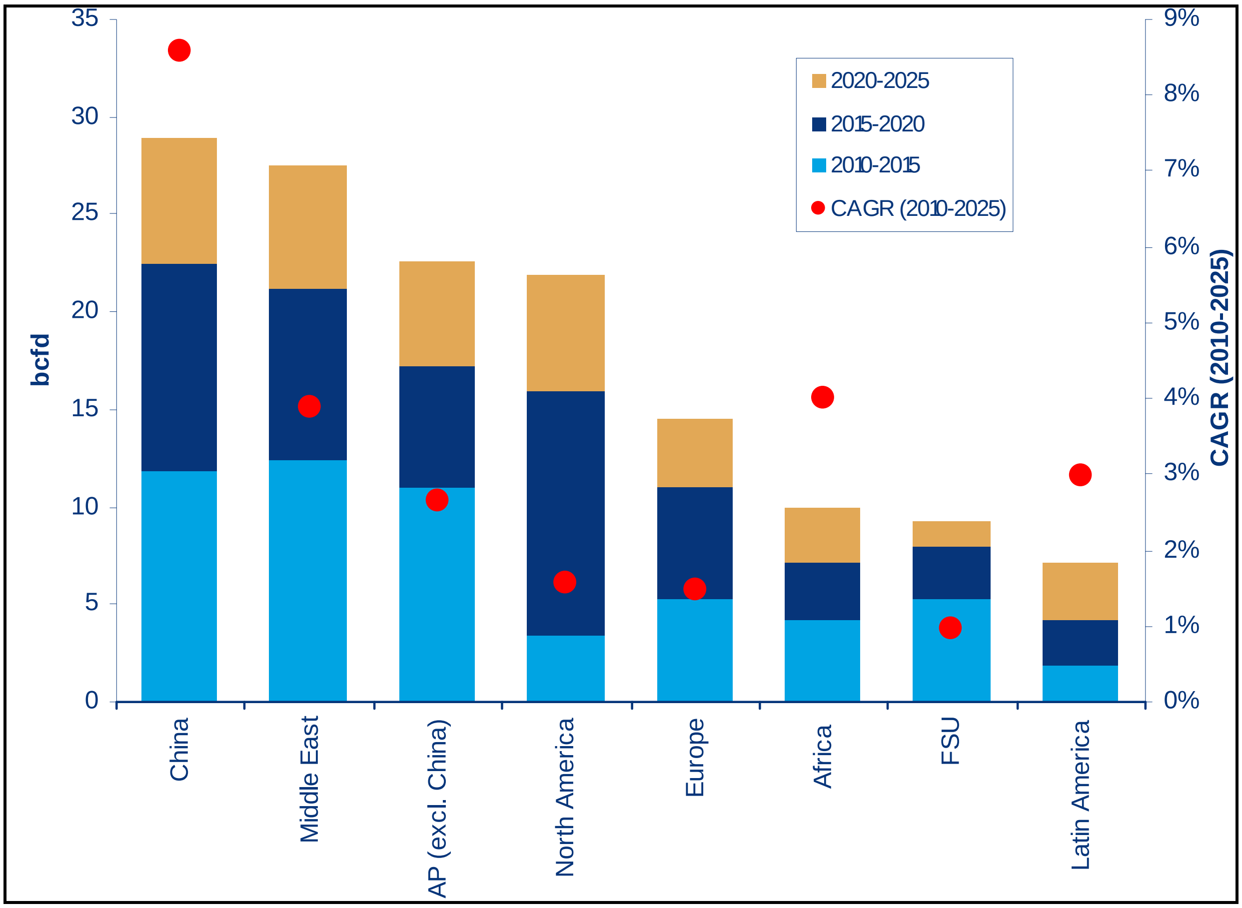
While Wood Mackenzie believes emerging Western Canadian shale and tight gas will still be economic, the expectation of a declining AECO-NIT price has provided motivation for producers to consider alternative Asian export markets to achieve higher returns on their investments. Wood Mackenzie will discuss the relative high-level economic spread comparison in section 6.

4. Global LNG Market Overview

4.1 Global LNG Supply/Demand Balance

Global demand for natural gas is forecast to rise substantially over the next 20 years. A disproportionate share of this demand growth will be centered in the eastern hemisphere, with China the fastest growing consumer. China's growth is driven by GDP growth and fuel switching as natural gas demand is expected to grow from approximately 11.9 bcfd in 2010 to 40.8 bcfd by 2025, of which 7 bcfd is expected to come from LNG.

Figure 9. Change in Regional Global Gas Demand (Piped + LNG)



Source: Wood Mackenzie

Eastern hemisphere countries, specifically the growing China and JKT economies, have limited access to domestic natural gas supply and will require more LNG compared to countries in Europe and especially North America. Wood Mackenzie expects the region to have total natural gas demand of 64.5 bcfd by 2025, of which, LNG comprises 33.9 bcfd.

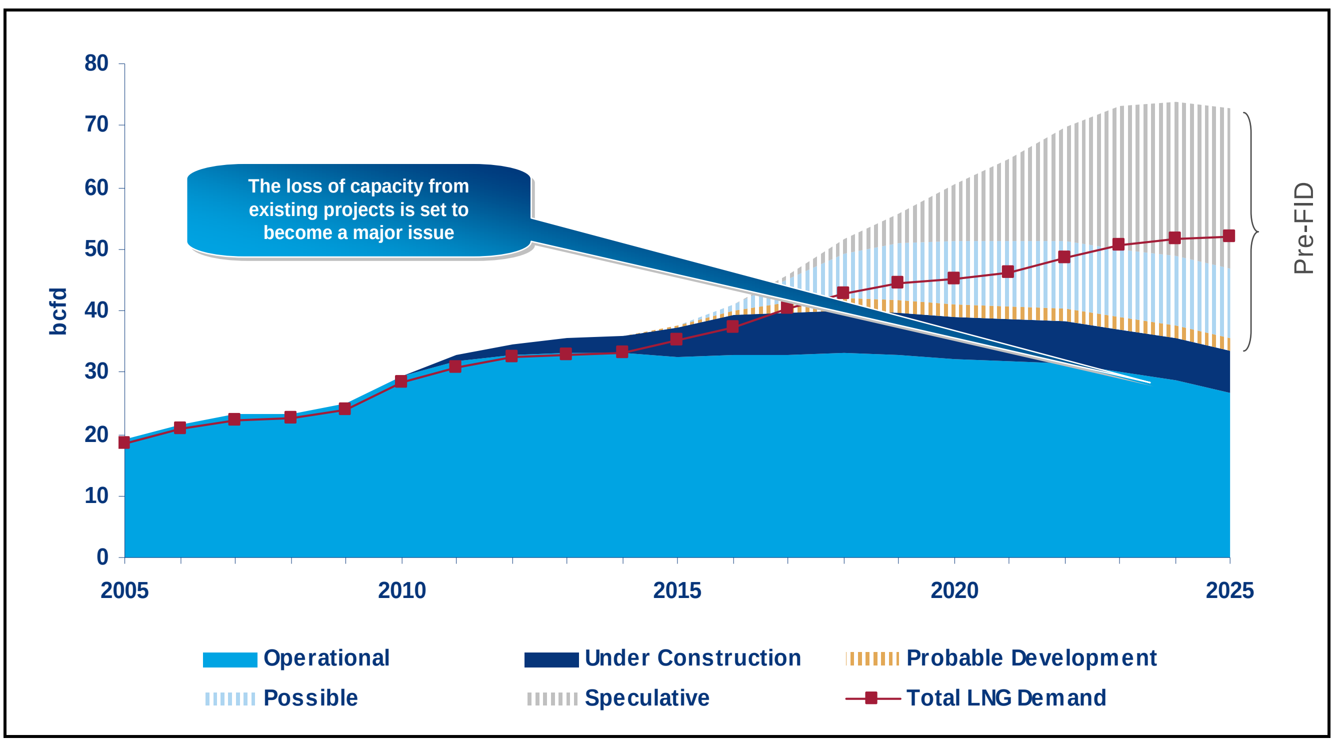
In contrast, natural gas demand in the Atlantic Basin is expected to grow more conservatively, with most incremental LNG demand growth in Europe. During the 2010-2025 period, total European gas demand is only expected to grow from roughly 59.0 bcfd today to 73.5 bcfd in 2025. European demand for LNG during this period is only expected to grow to 14.9 bcfd (compared to 33.9 bcfd in China and JKT). European demand growth will be chiefly driven by economics and fuel switching (coal and nuclear retirements, as well as switching from oil products). The regulatory environment will also have an impact as emissions regulations, fuel switching incentives, and similar programs could push the needle marginally farther toward natural gas if European governments push stricter policies than currently expected. While European countries have more access to traditional sources of natural gas supply, i.e. – indigenous supply and import pipelines, than China and JKT, indigenous resources are in decline. Existing pipelines are at or near capacity and newly proposed import sites to replace oil product imports will likely continue to drive growth in LNG demand.

While there is potential for development of shale gas, especially in China, shale is not expected to become a “game changer” in Europe or Asia as it has in North America. This is due to a host off issues, including the quality of shales, national boundaries (and therefore access and regime issues), lack of infrastructure, etc. Thus, LNG continues to be required to balance the Asian and European markets long term.

The LNG supply industry has been going through a period of unprecedented growth. During 2009, 6 bcfd of new LNG liquefaction capacity came online and a further 4 bcfd was commissioned in 2010. Qatar has been the main engine for growth, accounting for over half of the global increase and over a quarter of global LNG supply. However, the rate of development will slow considerably between 2011 and 2013, with only four projects (3 bcfd) scheduled to come online over the next three years compared to nine (10 bcfd) over the past two years due to the limited number of Final Investment Decisions (FIDs) taken in the 2006-08 timeframe.

By 2014, Wood Mackenzie expects the outlook will improve somewhat with Papua New Guinea and Gorgon in Australia expected to start operations. Globally, a potential shortfall in supply is forecast from circa 2016/2017 unless a number of pre-FID projects move forward and are successful in filling the supply/demand gap (see Figure 10). Atlantic Basin markets are expected to remain in oversupply for the near-term, while Pacific Basin markets will tighten considerably over the next four years. The potential for delays to start-up dates assumed in our analysis presents a significant risk. In addition, continuing uncertainty about the ability of several key legacy LNG supply projects to maintain production (typically because of feed-gas adequacy issues) creates potential for the supply/demand gap to be larger and/or to open up earlier. The Export Co-Op is one of a number of potential exporters intending to fill a portion of the potential gap, especially in Asia.

Figure 10. Global LNG Supply/Demand Balance

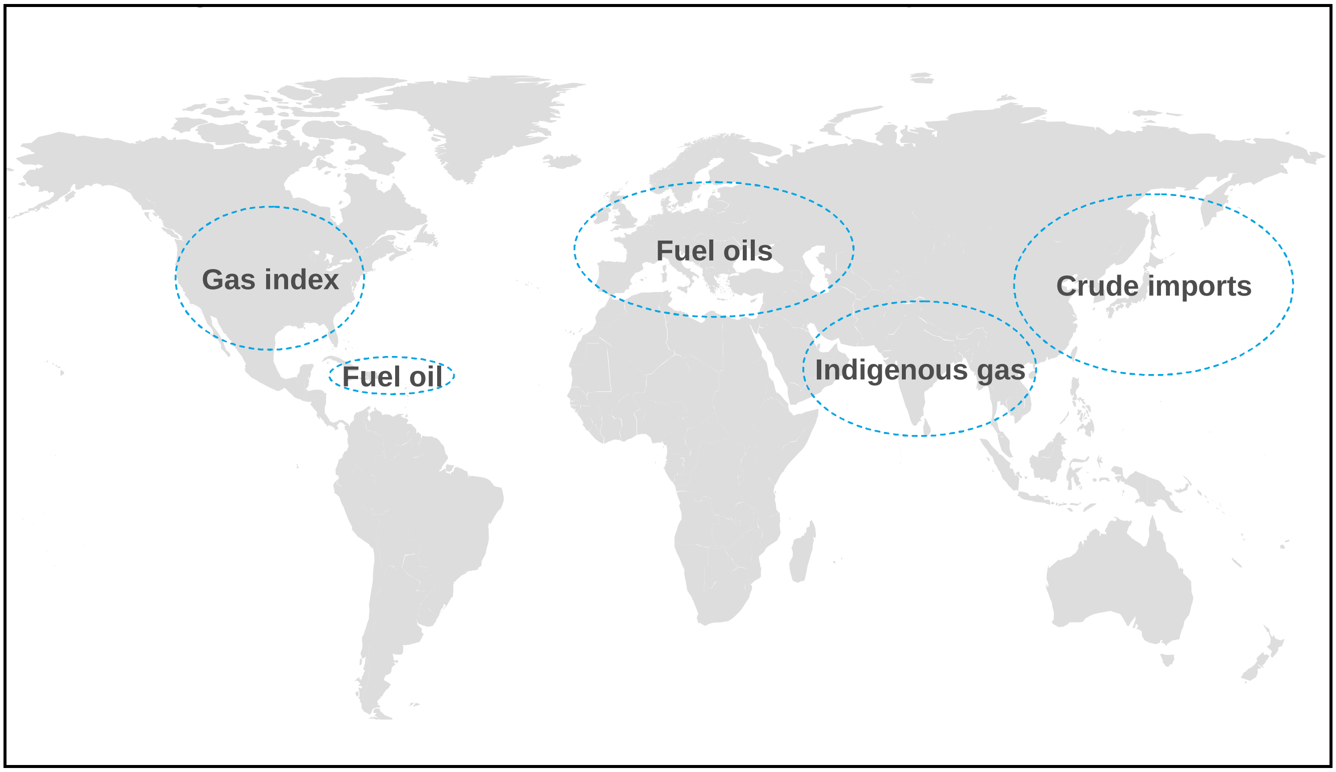


Source: Wood Mackenzie

4.2 Pacific vs. Atlantic Basin Markets

Except for North America and certain small markets, natural gas, and subsequently LNG, is generally priced against alternative energy sources globally. In Asia and Europe, the primary competitor to natural gas is oil and oil distillates, which has resulted in contract pricing for LNG that is in some manner linked to oil in most major markets.

Figure 11. Global View of Historical Regional Natural Gas Price Setting Influences



Source: Wood Mackenzie

Historically, natural gas prices in Europe have been indexed to Brent Crude using a formula that multiplies the per barrel oil price times a percent value, generally between 11 – 12%, to create a natural gas price per mmbtu. For example, a $100 per barrel Brent price will yield an $11 – 12/mmbtu natural gas price using this formula. Asia, being more dependant on LNG, has been willing to sign contracts with a similar linkage to oil, albeit with a higher percentage, and often with a fixed "adder" (loosely representing shipping costs). It is common to see a 14+% of Japanese Crude Cocktail ("JCC", a calculated average of oils imported into Japan per barrel which is roughly 99% of the Brent oil price) + a fixed adder. The result is a price strip that is higher per mmbtu than Europe, and significantly higher than North America.

North America's recent natural gas supply surge has allowed gas prices to disconnect from the oil-price link over the last several years. Henry Hub prices are now linked to the marginal natural gas development costs and at times, is supported by coal prices. With global oil prices significantly higher than North American gas prices on a btu basis, a widening spread is developing, providing potential price "head room" and therefore opportunities for LNG exports from North America.

5. Pacific Basin LNG Market Dynamics

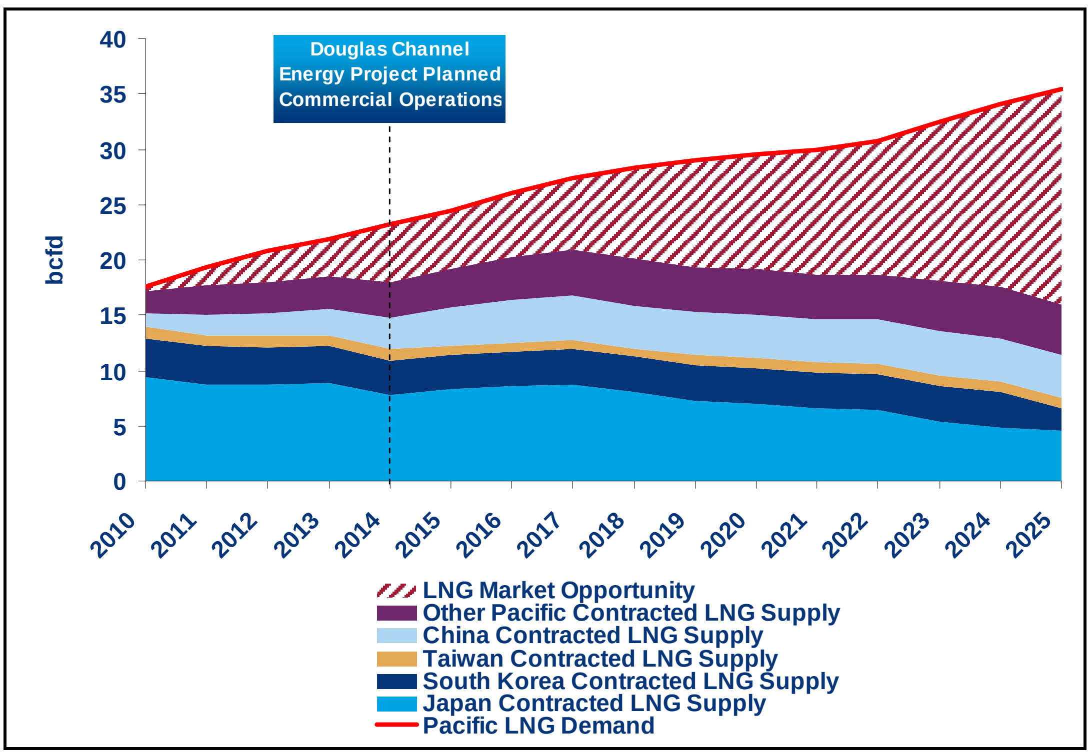
5.1 Pacific Basin LNG Supply/Demand Balance

The Pacific Basin LNG market today is characterized by a lack of indigenous supply in the traditional large gas markets of Japan, Korea and Taiwan ("JKT"). Thus, the JKT markets display a high level of dependence on LNG and a willingness to pay a higher price than is generally seen in Atlantic markets. In addition, China's economy continues to grow at a rapid pace. Wood Mackenzie views natural gas as key to China's industrial growth and pipeline capacity from indigenous supply is highly utilized. While China continues to invest in developing indigenous supplies and in piped import projects, LNG is increasingly complementing pipeline supplies. These four key Pacific Basin LNG demand markets account for 89% of total Pacific Basin LNG demand in 2010 and 63% by 2033. Other developing LNG markets display considerable growth, especially India. The Pacific Basin un-contracted LNG supply position should reach 20 bcfd by 2025 (Figure 12 below).

While LNG project development was slow in the Pacific basin over the last several years, a host of new projects, especially in Australia, are scheduled to come on line or take FID in the near term. However, with a typical 4-5 year liquefaction project development timeline from FID, a significant gap between potential demand in the Pacific Basin and LNG supply will develop before several large liquefaction projects come online in 2015/2016 providing a short-term increase in the supply-demand gap.

Today significant volumes of gas are being redistributed throughout the Atlantic Basin, as well as diverted from the Atlantic Basin to rapid growth Pacific Basin markets in order to rebalance the global LNG market. These redistributed cargoes have helped balance the Pacific market and have allowed LNG producers to take advantage of higher prices received for cargos in Asia. However, with rapid growth in Asia and recovery in Europe, new sources of LNG will be required. Incremental needs of Europe will begin "eating" into current Atlantic Basin LNG surpluses and by 2016, additional projects will be required globally to meet all anticipated demand.

Figure 12. Pacific Contracted LNG Supply vs. Wood Mackenzie Forecast LNG Demand

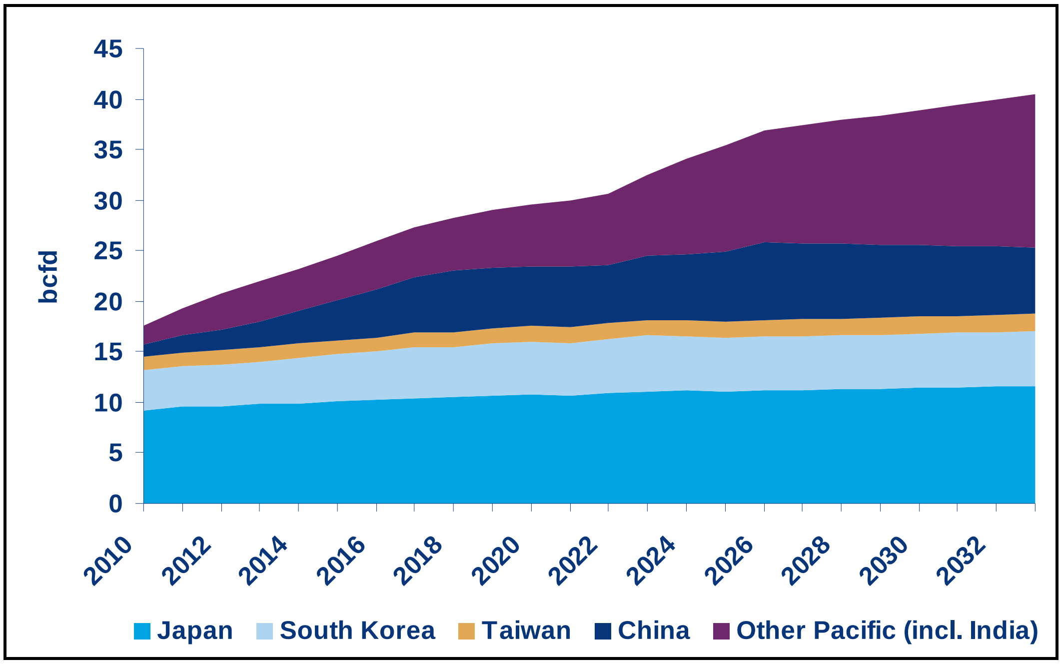


Source: Wood Mackenzie

5.2 LNG Demand Fundamentals: 2011 – 2033

Wood Mackenzie forecasts Pacific Basin LNG demand to increase from 17 bcfd in 2010 to 40 bcfd by 2033, or 3.7% per annum. Wood Mackenzie expects the key four Pacific Basin LNG importing countries (China, JKT) to continue to display considerable growth in LNG demand through 2033 as will other emerging Asia-Pacific markets (specifically, India). LNG demand across JKT and China will grow from 16 bcfd in 2010 to 25 bcfd by 2033 (see Figure 13). Un-contracted LNG demand is expected to grow to more than 14 bcfd across the four largest demand markets by 2025.

Figure 13. Wood Mackenzie Asia Pacific Basin LNG Demand Forecast: 2010 – 2033



Source: Wood Mackenzie

China

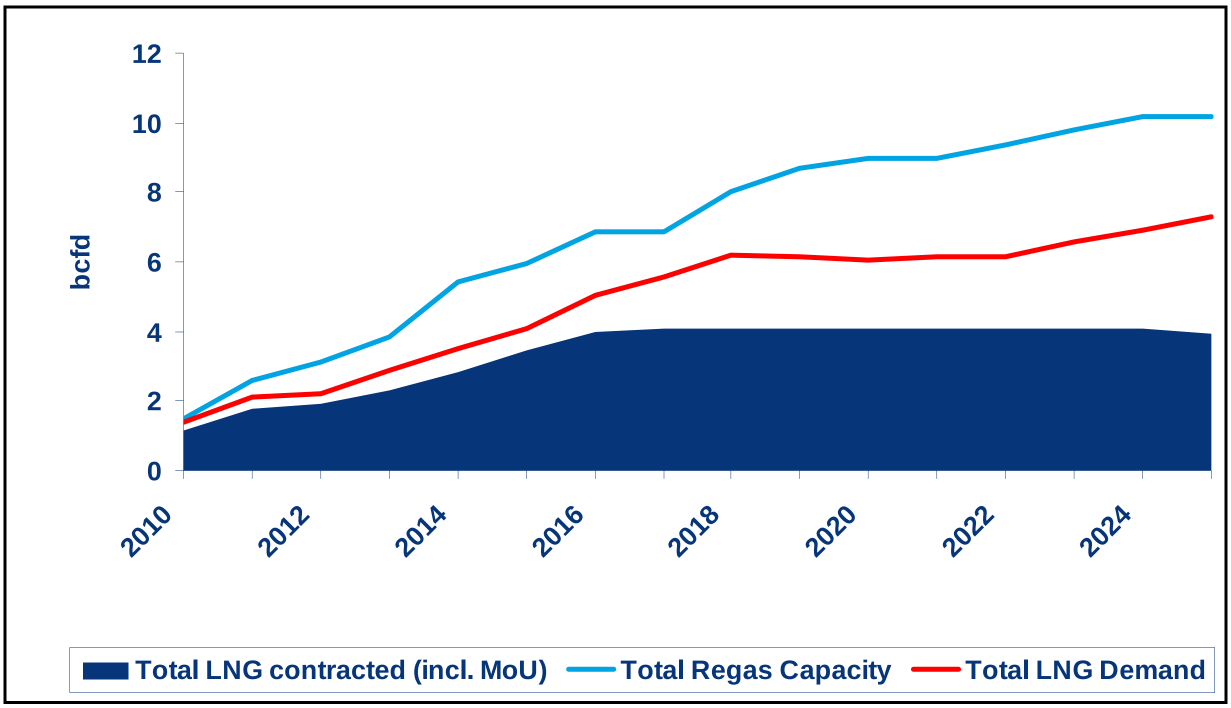
China is a rapidly developing gas demand market, driven by strong near double-digit economic growth and a desire to provide more economical energy options to consumers. In 2010, China's demand for natural gas was 10.7 bcfd. China's gas market is forecast to grow by more than 18% per year for the next three years and by 12% CAGR from 2009 - 2020. This strength in demand is driven by a combination of factors and not simply by the strength of China's broader economy. The dramatic pace of gas infrastructure development, latent demand for gas to displace oil product use and a ramp-up of gas supply available from domestic and imported gas supply projects will all help to expand the market.

Gas use in the industrial sector has dominated overall gas demand in China, contributing more than half the market historically. This includes demand from the fertilizer sector, predominantly located in inland China, close to existing gas supply basins. Going forward, however, we forecast stronger industrial gas demand growth in coastal regions. In more economically advanced provinces such as in Southern and Southeast China, gas growth in industry will be driven by competition with oil products. Wood Mackenzie forecasts China's industrial demand to grow from 6.1 bcfd in 2010 to 31.2 bcfd by 2033.

Indigenous gas production in China is expected to grow from 9.8 bcfd in 2010 to 35.6 bcfd in 2033. This volume is not adequate to match the pace of Chinese demand growth. Thus, the Chinese share of total gas supplied by piped and LNG imports is expected to grow from 8% in 2009 to over 55% in 2020. Given this expectation, LNG demand will likely grow 7.7% per annum to 2033 (from 1.2 bcfd in 2010 to 6.6 bcfd in 2033). China will therefore account for 25% of total global LNG demand growth. Wood Mackenzie forecasts China's un-contracted LNG supply position to be approximately 3.1 bcfd by 2025 (see Figure 14).

The expectation that natural gas will account for just 9.2% of total energy demand in China by 2025 implies there is definitely potential upside for natural gas use to grow more. Should this occur and indigenous gas production (especially unconventional prospects) disappoint, proposed import pipelines from Central Asia and Russia do not materialize, China imposes greenhouse gas emissions targets, or inland conversion rates to natural gas increase above expectations, the opportunity for increase imports of LNG can be significant.

Figure 14. China LNG Demand, Contracted LNG, and Regas Capacity



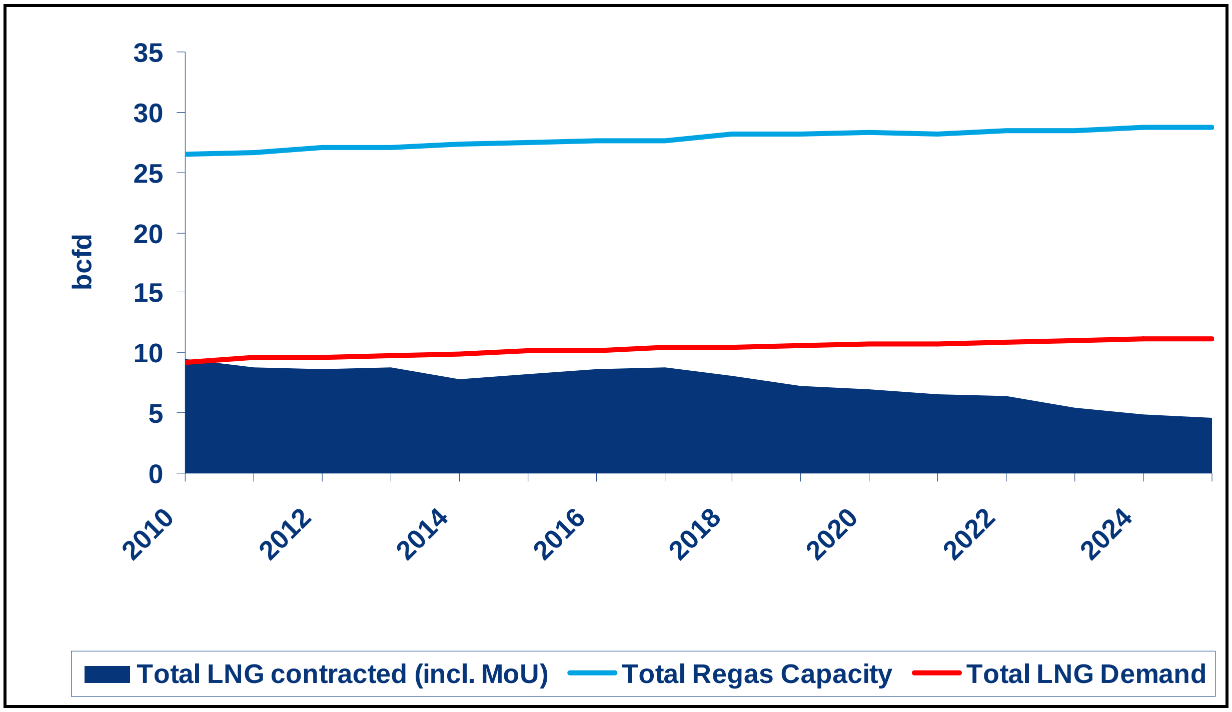
Source: Wood Mackenzie

Japan

Japan is the largest LNG market in the world with 9.2 bcfd of contracted LNG in 2010. There is virtually no indigenous production in Japan. The focus on security of supply, the lack of pipeline transmission within the country, regional fragmentation of gas and power corporations and seasonality requirements have contributed to an excess of regas capacity in the country. The surplus capacity is approximately double the volume actually contracted, allowing the potential to store excess liquid for "emergency" use, or to allow for growth in demand.

Wood Mackenzie forecasts LNG demand to grow modestly at 1.0% per annum reaching 11.6 bcfd in 2033. Additionally, an incremental supply gap emerges due first to the expiry of Bontang LNG and then Brunei LNG long-term contracts. This gap grows further with the expiry of the MLNG contracts in 2018 and ADGAS in 2020. Japanese buyers are the most heavily exposed of all Asian LNG buyers to the expiration of legacy LNG contracts during this decade. In many cases, it is not clear what level of volume the supply project can offer under an extension of the contract and for what duration. Evidence to date seems to suggest that buyers are seeking to cover about 50% of their potential exposure to loss of these volumes by signing new long-term deals with new suppliers. Wood Mackenzie does not anticipate any alternatives to LNG materializing in the long-term to serve the Japanese markets. We anticipate Japan will remain reliant on LNG for is natural gas needs. Additional gas demand may develop as prolonged use of existing nuclear capacity and approval of new nuclear capacity to meet generation requirements may be politically problematic. There is however currently considerable uncertainty about the relative longer-tern role of LNG/nuclear in the Japanese power generation fleet. As a result, some Japanese power generators have recently shown interest in shorter duration LNG contracts in order to try and mitigate the risk of their being long LNG if nuclear is ultimately deemed more important. Currently, Wood Mackenzie forecasts Japan's un-contracted LNG demand position to be 6.5 bcfd in 2025 (see Figure 15).

Figure 15. Japan LNG Demand, Contracted LNG, and Regas Capacity



Source: Wood Mackenzie

South Korea

South Korea is the second largest LNG market in the world, importing 3.9 bcfd in 2010. Similar to Japan, there is minimal indigenous production in the country. The global economic downturn reduced demand in 2009 resulting in a smaller gap between contracted supply and demand, and therefore fewer un-contracted deliveries of LNG than anticipated. This provided a temporary respite in the growth in LNG demand for the region and has allowed diverted supplies from the Atlantic to meet demand growth. Wood Mackenzie forecasts a strong recovery of gas demand in South Korea through 2012 as the economy recovers, driven by the industrial and power sectors. The contracted LNG supply gap widens steadily from 2012 – 2018 as demand growth continues, and legacy long-term LNG contracts from South East Asia begin to expire. Thus, over the next decade, key buyers (e.g. KOGAS) will have to source up to 0.7 bcfd of supply, over and above incremental growth.

Wood Mackenzie forecasts incremental LNG demand growth in South Korea to grow from 3.9 bcfd to 5.4 bcfd by 2033 or 1.4% per annum largely driven by the power sector. There is currently discussion of a potential Russian import gas pipeline, however we do not include it in our current forecast. Thus, South Korea's un-contracted LNG demand position is forecast at 3.3 bcfd in 2025.

Taiwan

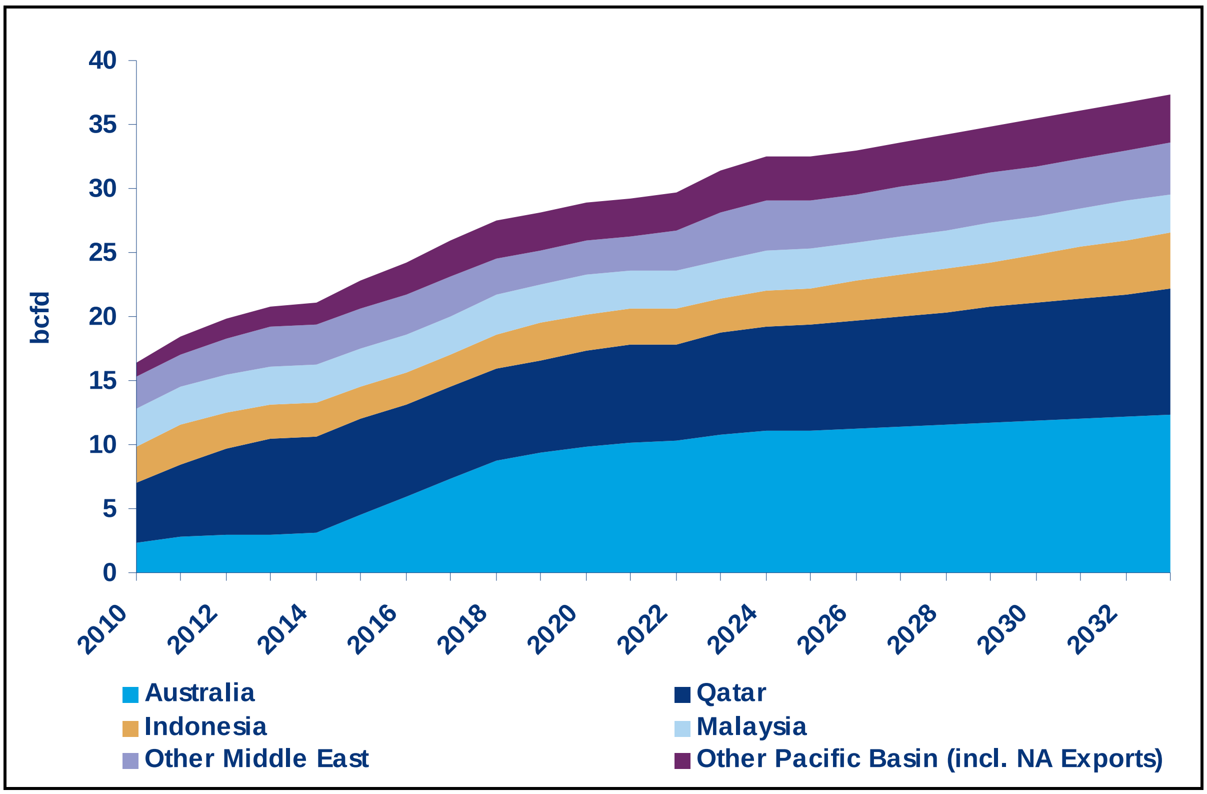
Taiwan is an important Pacific Basin LNG market with 1.3 bcfd of demand in 2010, roughly the size of today's Chinese LNG market. Wood Mackenzie expects Taiwan's LNG demand to remain relatively flat through 2033, reaching 1.7 bcfd, a modest growth rate of 1.1% per annum due to a continued dependence on coal-fired power generation. Expiring contracts, however, will result in Taiwan requiring additional new LNG contracts through the period of the study.

Other Pacific Basin LNG Import Markets

Other Pacific Basin markets, including an emergent India and other sizeable LNG importing countries such as Indonesia and Singapore accounted for 1.9 bcfd of demand in 2010. Wood Mackenzie expects rapid growth rate of 9.4% amongst other Pacific Basin LNG import markets through 2033, reaching 15.1 bcfd. The key Indian LNG import market is expected to match China's LNG import requirement long-term and will be joined by the fast-growing Singapore and Pakistan import markets as key growth drivers.

5.3 LNG Supply: 2011 – 2033

Figure 16. Potential Pacific Basin LNG Supply



Source: Wood Mackenzie

Wood Mackenzie forecasts potential Pacific Basin LNG supply to grow from 16.4 bcfd in 2010 to 37.4 bcfd in 2033, representing 3.6% growth per annum (see Figure 16). Potential LNG Supply projects in the Pacific and Middle East Basins outnumber the projects in the Atlantic Basin by a ratio of 2:1. Near-term growth will be provided mainly by the Qatargas-3 and Qatargas-4 projects, expected to ramp up through 2013. Seven new Australian projects are included in Wood Mackenzie's LNG supply forecast over the next 10 years as Australia rapidly becomes a key producing country. Australia accounts for over 40% of the capacity under construction with completion expected in the 2011-2015 timeframe. The large Pluto and Gorgon projects are among these. However, given the long lead times of 4-5 years from FID sanctioning to operation of the facility, the scope for bringing additional capacity on-stream in the Pacific Basin prior to 2015 is very limited. The implication is that the Pacific LNG market should remain tight through 2016 and potentially beyond.

Several factors will impact the development of new LNG projects including, but not limited to, the following:

- Local market demand competition as evident in Indonesia – strong demand for gas from 'local' markets and prioritization of that demand over LNG exports;
- Moratoria on new LNG projects (e.g. Qatar) and geopolitical challenges in others (e.g. Iran);
- Technical challenges – including requirements for new technologies to liquefy remote offshore resources (e.g. Floating LNG projects such as Prelude);
- Permitting and approval challenges – gaining approvals/permits at national and local levels to cover environmental, commercial, regulatory, safety and technical matters can delay projects, particularly in environmentally sensitive areas;
- Partner alignment – different approaches, vested interests and disagreements between project partners can delay project developments. For example, the Australian Browse project has been delayed by a protracted disagreement between the JV partners on a preferred development concept;
- Capital cost outlook – Costs vary project by project, depending on a range of factors including location, environment, scale, EPC availability, raw material and equipment costs, infrastructure, timing of project sanctioning, dredging requirements and requirement for domestic input within the host country. Costs have escalated significantly since 2006. Many of the projects brought onstream in 2009 and 2010 were sanctioned before the costs escalated – for example the costs for the integrated Qatari projects are in the $US400-600/tonne range. In comparison, costs for liquefaction projects currently under construction and due on-stream in the 2011-2014 timeframe are in the $US1,200-1,400/tonne range. Where detailed project costs are unavailable, Wood Mackenzie uses a range of estimates for longer term projects,. Our current assumption for major greenfield projects is typically $US1,100-1,300/tonne. Higher costs are applied for harsher environments and FLNG projects, lower costs for brownfield projects.

It is difficult to accurately forecast which projects will proceed and which will be delayed or cancelled. It is entirely possible that some additional projects will be developed. The Pluto field, for example, was only discovered in 2005 but has moved ahead of several competing projects and is now expected to be operational by 2011. Wood Mackenzie associates an earliest potential start date with each project based on what is currently known. Our assumptions tend to be more conservative than those of the project developers'. Several key uncertainties that could shift the Wood Mackenzie Pacific Basin LNG supply outlook are included below:

- <u>Pace of Australian LNG growth</u> – Technical challenges, environmental approvals, access to resources in competition with the booming mining sector and partner mis-alignment may constrain the output of Australian LNG more than we have assumed.
- <u>South East Asia LNG output</u> - Collectively, Indonesia, Brunei and Malaysia have over 5 bcfd of capacity over 25 years old. There is downside risk to our expectations of feedgas replacement to ensure our output expectations from these plants. The maturity of the facilities pose risks for reliability and the availability of upstream reserves to feed the plants. Bontang concerns are the biggest. Continued delays to the signature of the offshore Mahakam PSC extension and uncertainty around the development of deep water fields/CBM and possible diversions to the domestic market are major concerns.
- <u>Upside to modest Qatari growth</u> – Qatar's longer term growth is modest compared to its potential. Qatar could provide significant additional LNG export capacity over and above that assumed.

5.4 Pacific Basin LNG Pricing Terms & Conditions

Oil indexation (tied to JCC and generally including a fixed component) has traditionally dominated long term gas contracts in Asia, but its relevance has been brought into question by the current global gas over-supply and pressure in Europe for greater levels of spot gas indexation. It is widely recognized that sellers of gas into the Pacific Basin are keen to retain oil indexation, Wood Mackenzie also believes that many Asian buyers and policy makers will continue to accept oil indexation. Natural gas still substitutes for oil products in much of Asia, particularly in China and India where the industrial and residential/commercial sectors are driving gas demand. Other reasons why Asian buyers are reluctant to move significantly away from oil indexation include the predominance of pass through pricing regimes, the fragmentation and conservatism of buyers, the lack of an Asian hub price, the unfamiliarity with Atlantic spot price risk (and concerns around Henry Hub and NBP price volatility), and the strong current desire to launch new Pacific Basin LNG supply projects. Consequently Wood Mackenzie's expectation is that oil indexation will remain the backbone of long term contracts in Asia. Asian buyers generally seem happy to retain oil-indexation in contracts, their concerns are typically centered around the level of indexation to oil.

Long-term Australian conventional LNG pricing has fallen slightly since the 2008 market peak (Gorgon deals were completed at 15.5%, but has remained resilient in the challenging markets of 2009 and 2010. Most deals for conventional LNG (i.e. not CSG LNG) completed incorporated a 14.85% slope (percentage) of the JCC index. Thus, Wood Mackenzie's global oil price outlook is critical in determining the likely range of Pacific Basin LNG contract pricing on a btu basis.

Wood Mackenzie's oil price outlook calls for $90 - $100/bbl (real 2010$) global oil prices from 2012 – 2025 and reaches $135/bbl by 2033 (averaging of $97.50/bbl from 2011 - 2033) supported by long-term fundamentals, including robust growth in key emerging economies, rising global income, a growing middle class, and slowing global oil supply growth result in tightening spare capacity.

Wood Mackenzie forecasts increasing global oil demand over 15 million bpd from 2010 to 2020. A further 8 million bpd from 2020 to 2030 is expected as demand climbs from 86 million bpd in 2010 to 109 million bpd. Supply growth in non-OPEC countries is forecast to grow more than 5 million bpd to peak in 2022. OPEC spare capacity is forecast to fall from 6.8 million bpd in 2010 to just 1.4 million bpd by 2030 to keep up with the rising global appetite for oil. The result is an ever tightening oil market. Risks to the outlook include unexpected oil supply (e.g. Iraq), the emergence of tight oil production, deviations in GDP growth rates, political instability, and changes in expectations for either fuel efficiency or the use of alternative transport fuels.

In this context, Wood Mackenzie believes long-term LNG deals in Asia will continue to achieve 13 – 16% slopes relative to oil prices, varying with LNG market supply-demand cycles. Rising associated supply project costs have set a "floor" on delivered prices above $11/mmbtu for financing purposes, large liquefaction projects require robust net present value (NPV) economics.

Wood Mackenzie has used a range of average oil prices between US$75/bbl and $110/bbl (real 2010$) over the 2011 – 2033 time frame. JCC slopes from 13 – 16% (plus shipping) have been applied to the oil forecast to calculate expected firm contracted Asian LNG delivery prices between $11/mmbtu - $18/mmbtu across the range of scenarios. Furthermore, our assessment of the economics of various supply projects indicates that most should be able to generate a breakeven return based on the assumed oil-price and LNG/oil indexation levels. We would note though that most developers will look to secure LNG pricing levels that are expected to generate higher than breakeven returns.

6 Conclusion

Wood Mackenzie reached the following conclusions relative to the proposed Douglas Channel Energy Project:

- Overall, Canadian gas production is expected to increase above the 2001 peak of 17.5 bcfd by 2025, and will continue increasing slowly to 18.7 bcfd by 2033;

- With a robust view of Canadian supply mid-term, WM believes WCSB production will continue to meet demand in the basin, ultimately outstripping local oilsands-dominated demand growth resulting in increased regional exports of WCSB gas. Natural gas leaving the WCSB is expected to increase from 9.0 bcfd in 2011 to 10.5 bcfd in 2020 before declining to 9.1 bcfd by 2033;

- Natural gas demand in Pacific Rim Markets will account for a disproportionate share of what is anticipated to be a substantial increase in the demand for natural gas over the next 20 years;

- There is a global LNG supply/demand imbalance forecast beginning in 2016/17 and increasing in significance to 2025;

- Within the Pacific Rim, contractual LNG Supply is falling short of demand today, being supplemented with temporarily surplus Atlantic basin cargos through 2016, when new sources of LNG will be required;

- Outside North America where gas prices are linked to the marginal costs of natural gas development; most natural gas prices globally are directly linked to world oil prices. In North America, natural gas prices have become de-linked from oil prices and instead;

- The current differential between global natural gas prices and North American gas prices is sufficient to permit Canadian producers to recover the full opportunity cost of dedicating production to DCEP, DCEP's cost of transporting and liquefying natural gas, and all other costs to be incurred in Canada to facilitate the exports contemplated in this Application; and

- The spread between North American natural gas prices and world oil prices is forecast to increase over the next 20 years allowing Canadian LNG exports over that period to recover all costs incurred in Canada to facilitate the export.

In summation, the significant potential for otherwise unfilled demand in Pacific Rim markets over the study period should lead to an attractive cost/value spread between North America LNG and markets in Asia and thus provide a unique opportunity for participants in, and beneficiaries of Canada's natural gas industry to obtain added value from LNG exports.