Proposed Energy East Pipeline Project White Paper

Prepared for Société en commandite Gaz Métro and Gazifère Inc.

September 2, 2014

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Wood Mackenzie

Executive Summary and context of this report

On July 4, 2014, the Government of Quebec requested that the Régie de l'énergie (the "Régie") provide its opinion with respect to gas demand during the 2015-2030 period, as well as gas supply and gas transportation to Quebec, as foreseen by Section 42 of the Régie de l'énergie Act. On July 18, 2014, the Régie required from Société en commandite Gaz Metro ("Gaz Métro") and Gazifère Inc. ("Gazifère") to obtain and file expert opinions on these topics.

The purpose of the present report is to shed some light on the gas supply as well as gas transportation to Quebec, amongst other things, in the context of TransCanada Pipeline Limited's ("TransCanada's") proposed Energy East Pipeline Project ("Energy East").

Gaz Métro commissioned Wood Mackenzie to analyse gas fundamentals in markets served through TransCanada's Eastern Ontario Triangle in the context of evolving North American gas markets with and without Energy East. As such, our mandate covers both Gaz Métro and Gazifère's franchise areas. The report presents our finding in three sections:

- **Section 1. North American gas markets.** The first section of the reports presents a continental outlook covering supply, demand and regional prices based on emerging and established low-cost shale gas and tight oil resource, gas-intensive power, industrial and export projects designed to capitalize on that resource, and existing and planned pipeline and storage projects designed to transport the gas.
- **Section 2. Quebec and Eastern Ontario markets.** Section 2 addresses demand potential, supply sources, and pricing in Quebec and eastern Ontario markets, along with demand in New England and New York markets served through eastern Canadian pipelines. Because TransCanada's infrastructure is the only means to serve the region of Québec and eastern Ontario, and there is an application before the National Energy Board ("NEB") requesting, among other things, changes to the transportation rates along supply routes into the region, Wood Mackenzie addresses implications for supply access and pricing under both the current compliance tolls and the proposed settlement tolls.
- **Section 3. Impact of Energy East.** Section 3 discusses Energy East and implications for gas supply and transport adequacy into Quebec.

Conclusions:

- **North American Markets appear well-supplied**, even though LNG export projects, gas-intensive industrial projects, and new gas-fired power capacity will accelerate the pace of growth in new markets over the next 15 years. Henry Hub and AECO prices are expected to average \$4.80/mmbtu and \$3.80/mmbtu respectively through the study period.
- **Not all markets feature low-cost or immediate access to low-cost supplies;** eastern Canadian markets have some access to proximate low-cost supplies in the Marcellus and Utica today, and prospective areas like Quebec Utica Shale and Anticosti island could provide regional supplies in the future, but settlement tolls provide optimal access to those supplies, and delays implementing the settlement tolls and associated projects increase the cost of delivered supply into the region.
- **The Energy East project does not impact flows or pricing in the Prairie or Northern Ontario section of TransCanada's Mainline, nor does the project impact Henry Hub or AECO prices.** However, the project does have a material impact on pricing and deliverability into EDA markets on cold winter days. Demand in those markets is expected to exceed delivery capacity even if temperatures hold close to norms starting in winter 2016/2017. On those days, prices must rise to match New England prices, and winter gas markets in New England currently price at oil product levels in order to shift power generation from gas-fired to oil-fired power units and preserve gas supplies for heating customers. On cold days in New England, prices rise toward \$20/mmbtu. According to forward price markets, New England is the highest-priced liquid market in the world for winter 2014/2015.
- **The number of constrained days and the price levels necessary to balance supply and demand on those cold days depends on the pace of pipeline development into New England markets.** A delay in the Northeast Energy Direct project—scheduled to come online in November, 2018—could expose Quebec consumers to peak month winter prices in the \$10 to \$12/mmbtu range. A delay in the Constitution pipeline beyond the November, 2018 Energy East conversion date would threaten system reliability in the EDA and New England regions. Even if the projects come online on schedule, winter delivered prices in Quebec increase by \$0.50/mmbtu between 2018 and 2021 if Energy East proceeds. In a cold winter, prices could rise by \$2.00/mmbtu.

- **Demand projects, supply potential, and the timing of pipeline expansions all remain highly uncertain.** Maintaining gas supply services to meet Quebec peak winter day demand requires either new pipeline capacity into New England or maintaining the existing 3.2 bcfd deliverability in eastern Ontario on the TransCanada Mainline.

The analysis presented in Sections 1 and 2 are based on Wood Mackenzie's Spring 2014 North American Gas Long-term Outlook. Wood Mackenzie updates Long-term Outlooks biannually, using the latest fundamental data and infrastructure project status available at the time. Robert Fleck's testimony for the eastern Shipper's group is consistent with the Spring 2014 Long-term Outlook. However, because the update is based on best-available information, and substantive assumptions were determined in February, 2014, subsequent developments suggest increased probabilities for different market outcomes:

- WCBS production potential increased.
- Settlement and eastern Canadian project development delayed.
- IFFCO fertilizer capacity firming up in Quebec.
- Timing on Northeast debottlenecking delayed.

In the report, Wood Mackenzie addresses the change, or discusses the qualitative impact of recent market developments on our conclusions.

Section 1 - Overview of North America Natural Gas Markets

In this chapter, we present an overview of Wood Mackenzie's outlook for North American gas markets over the next 15 years. This includes examination of key drivers such as drilling cost trends and technology developments. Production forecasts for key regions are then addressed, with focus on the major production growth regions, the US Northeast and the Western Canadian Sedimentary basin. We then examine changes in demand, focusing on two primary growth sectors: power generation and industrial facilities. Trade flows are then examined, looking at both cross-border pipeline flows between Canada, the United States and Mexico, and overseas trade via LNG transport. We wrap up the chapter by examining price forecasts. We first focus on pricing at the two major North American trading hubs, Henry Hub in the US and AECO in Canada, and we then look at pricing and infrastructure dynamics in several other parts of the continent.

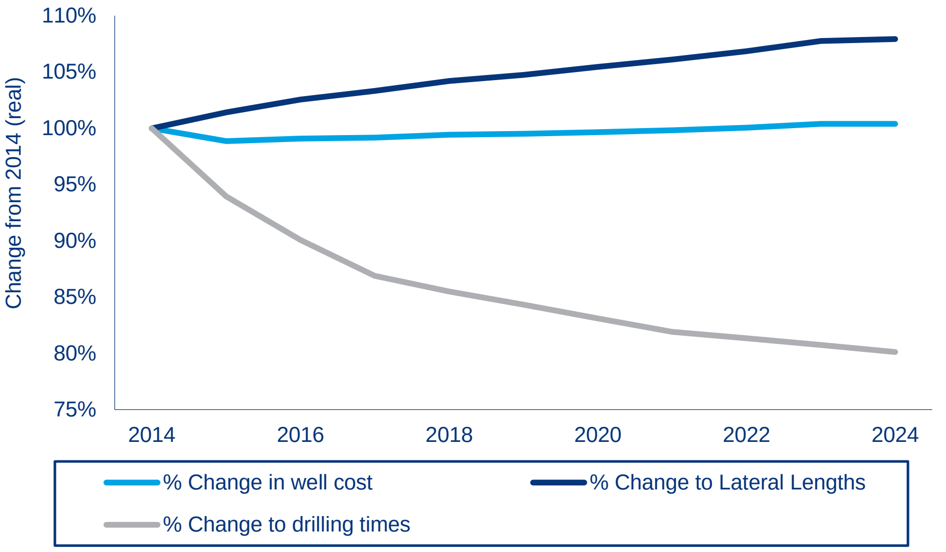
1.1 North America supply

Cost and productivity overview

We expect that 78% of new gas development between 2014 and 2020 will occur in plays with an average breakeven below \$3.50/mmbtu[1]. Well costs are expected to remain largely flat through 2024, as a 10% decline in real costs driven by greater rig efficiencies and well productivity is balanced by wells being drilled deeper, longer, and with more complex completions.

[1] All quoted prices are in real 2014 US\$/mmbtu.

Chart 1. Change in well cost, drilling times, and lateral lengths from 2014



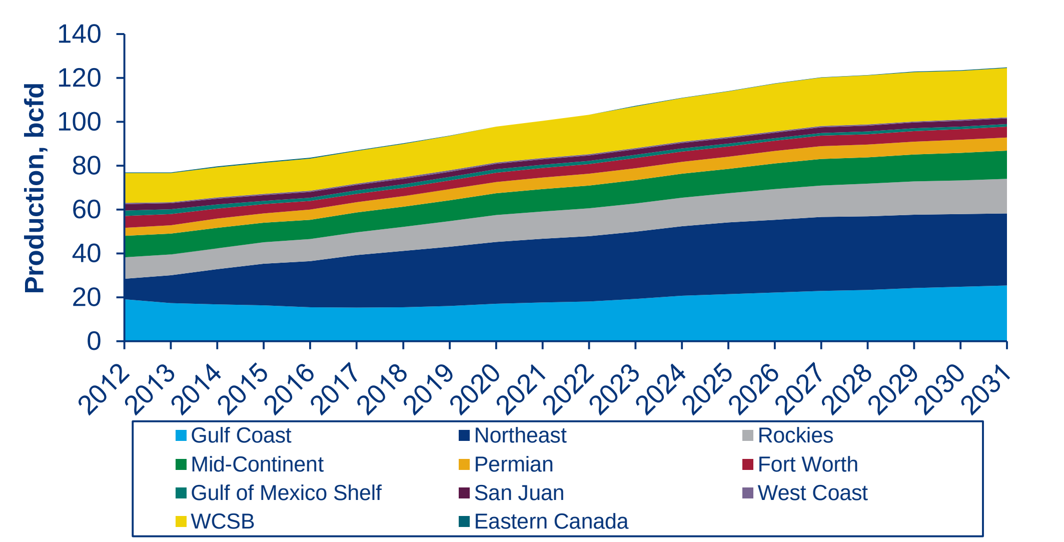
Source: Wood Mackenzie

Our outlook on costs is driven by several factors. Recent growth in high-spec rig and completion capacity has led to loosening in the markets for oilfield services, so costs have been falling. We expect rig day rates to increase by about 1% annually in nominal terms, meaning a decline in real dollars, and for real completion costs per lateral foot to decline 5-10% during the next two years before stabilizing. Per-well costs, though, will decline by a more modest amount, as these improvements in macro-level costs will be partly offset by an increase in lateral lengths.

As lease-holding by production is largely complete, many operators have turned to optimal acreage development, aiming to reduce costs and deliver efficiency gains. In early-stage plays such as the Utica, we expect improvement in expected ultimate recovery (EUR) per lateral foot, while in other, later-stage plays like the Haynesville we expect increasing EURs in proportion to increases in lateral lengths.

Costs are also expected to drop with a concentration of drilling in lower-cost plays. The Marcellus and Utica are expected to grow 12.4 bcfd from 2014-2020, equal to 31% of total US production, and much of the acreage in these plays makes money at under $3.50/mmbtu. Low cost associated gas volumes are surging as US upstream spending remains focused on tight-oil plays, especially the Bakken, Eagle Ford, Niobrara, and Permian. At the same time, smaller-scale oil-focused developments have been pushed forward. In the Mid-Continent, for example, associated gas will account for about 45% of new-drilled gas volumes through 2020, on the strength of the oil-prone areas of the Woodford shale, as well as the Mississippian and other niche oil developments.

Chart 2. Key region and play outlook



Source: Wood Mackenzie

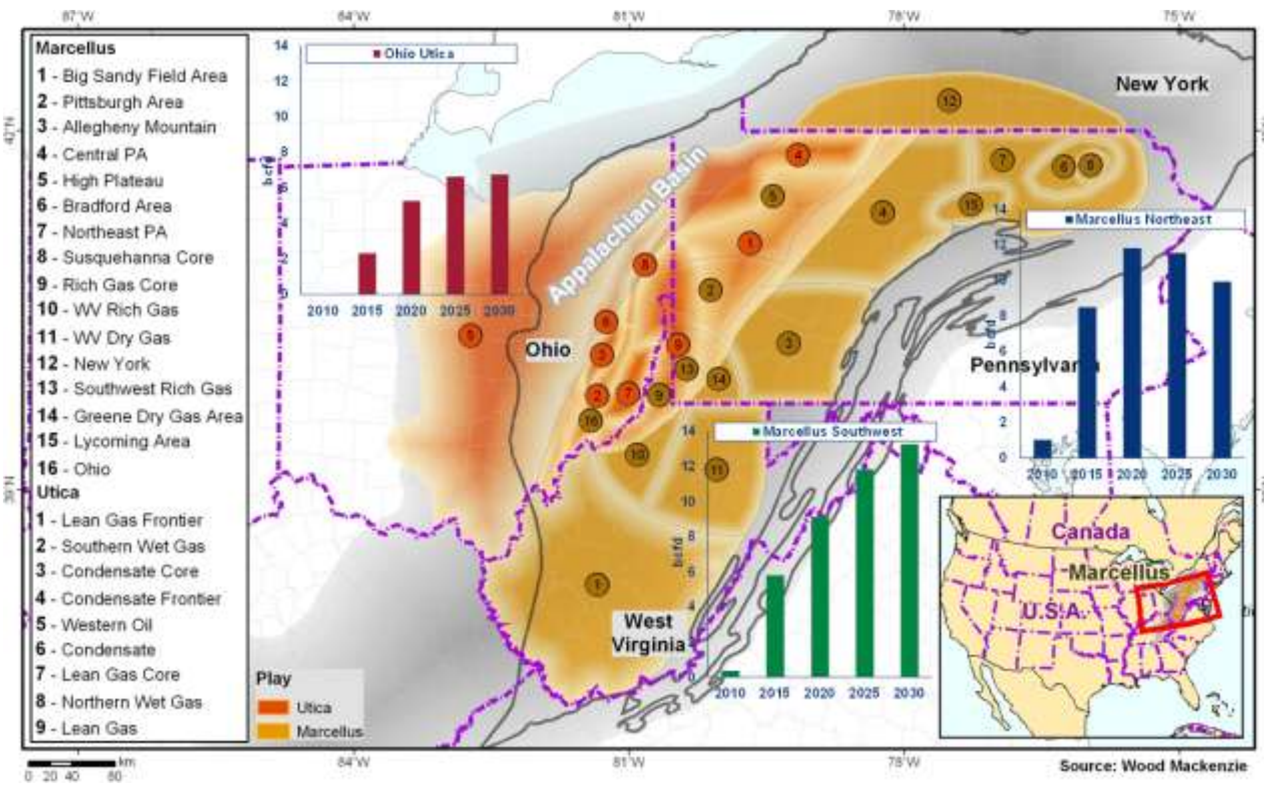
US Northeast: Marcellus and Utica supply profile

Table 1. Northeast US key play production, selected years, bcfd

	2010	2015	2020	2025	2030
Marcellus Northeast	1.0	8.5	11.8	11.6	9.9
Marcellus Southwest	0.4	5.8	9.1	11.8	13.3
Ohio Utica	0.0	2.3	5.3	6.6	6.8

The Northeast is expected to become the largest producing region in the US during 2015, with output growing to 28.2 bcfd--one third of US production--by 2020. The region is home to the Marcellus and Utica, which will dominate regional volumes, adding a combined 12.4 bcfd from 2014 to 2020 and 3.7 bcfd from 2020 to 2030. The Marcellus continues to be the most transformative development in the North America gas space, with production expected to average nearly 13 bcfd in 2014, from volumes near zero in 2008. Production from this shale is not expected to slow materially over the next several years, with total volumes reaching 21 bcfd by 2020 and 23.4 bcfd by 2025. The sheer size of this play dwarfs that of all other shales, and will account for over 40% of total US shale volumes in our outlook. The Northeast portion of the play has accounted for most of the production growth to-date and is home to the top producing wells. Production in this area reached 8 bcfd in 2014, nearly doubling over the past two years. This area is also home to the most pronounced price dislocations and has been the most restricted area due to infrastructure limitations. This area of the play will continue to face constraints from limited take-away outside of the producing areas, and as a result production will only grow 0.5 bcfd in 2015, before additional pipeline projects in 2016 and 2017 allow for production to reach nearly 12 bcfd by 2018. Beyond 2020, the area becomes less infrastructure-constrained, but the core areas of development around the Bradford, Susquehanna, and Lycoming sub-plays become more mature, and development will migrate south and west.

Chart 3. Map of sub-play Marcellus and Utica areas with production outlook



In the Southwest portion of the Marcellus, gas production includes both lean-gas areas to the east as well as rich-gas areas with NGLs and associated condensate production. The liquids value makes these core areas are some of the lowest-cost plays in the US, with breakevens below $3.00/mmbtu. To support this growth in rich-gas areas, significant investment in gas processing capacity has been made, with nearly 6 bcfd of capacity expected to be online by year-end 2015. Southwest Marcellus production is expected to grow from 4.8 bcfd in 2014 to 9.1 bcfd by 2020. Most growth comes in rich-gas areas, growing from 63% of production in 2014 to 85% by 2020. Longer term, Southwest development spreads to lean-gas areas, where production grows from 1.4 bcfd in 2020 to 2.7 bcfd by 2030, when total production from the Southwest Marcellus surpasses the Northeastern portion of the play.

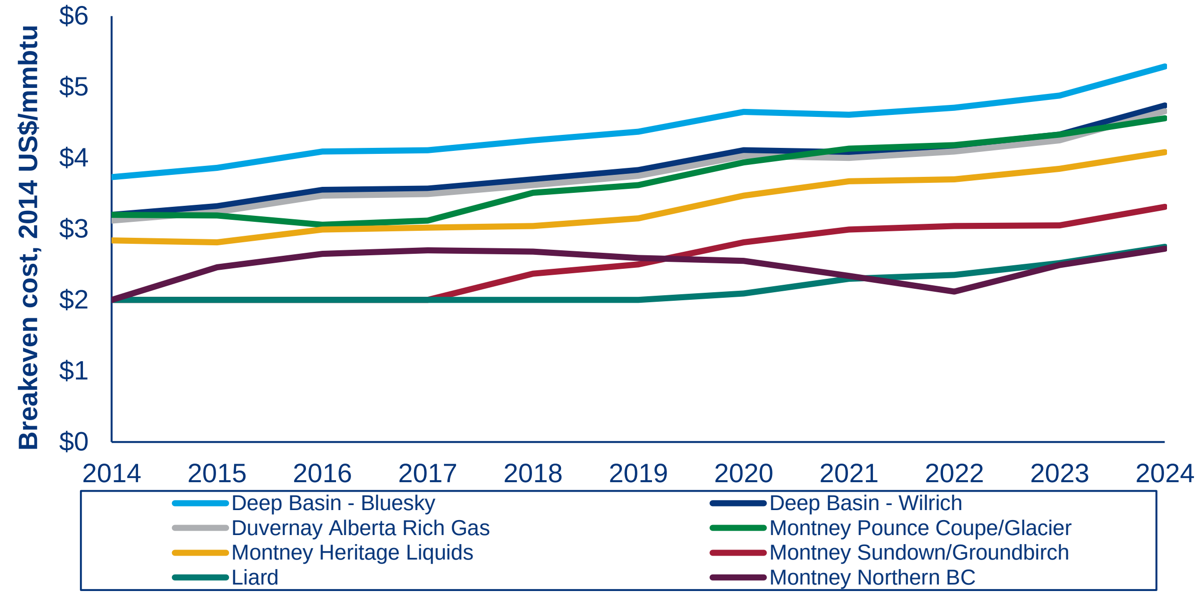
We expect Utica shale gas volumes to reach 2.3 bcfd by 2015 and 5.3 bcfd by 2020. This outlook is driven by positive well results reported by producers in the lean-gas areas of the Utica. Belmont and Monroe counties are the developing core area of the lean-gas areas, and have had wells with reported initial production (IP) rates up to 42 mmcfd. Due to the still-early stage of development across the Utica--there are less than 1,000 producing wells in 2014-- there remains uncertainty on the extent to which these recent well results can be replicated.

Producers have been more proactive in the Utica in signing up for both gas processing and NGL take-away capacity, and underwriting gas pipeline projects to enable gas delivery to regional markets. We believe these announcements are very supportive of both the long-term outlook for the play, and will keep infrastructure-driven constraints below levels observed in the Marcellus shale. Indeed, it appears there is more coordination between midstream infrastructure and upstream development, with some companies purposely building an inventory of wells prior to project start-up.

Revival of Western Canadian Sedimentary Basin

Conventional Canadian gas production has declined from a high of 17.4 bcfd in 2001 to a low point of 13.5 bcfd in 2013. This has largely been driven by a decline in drilling; expanding Northeast US shale production pushed prices down and cut investment in Canadian conventional gas.. The future of Canadian gas production will be highly leveraged to on-going unconventional development in the country's massive shale gas resources. Gas production from the Montney, Duvernay, and Horn River shales will reach 8.5 bcfd by 2020 and 13.2 bcfd by 2025. Despite the focus on unconventional gas and oil plays, conventional targets are also seeing a renaissance as new technologies pioneered in shale developments are applied to formations across the WCSB.

Chart 4. WCSB breakeven cost trends



Source: Wood Mackenzie

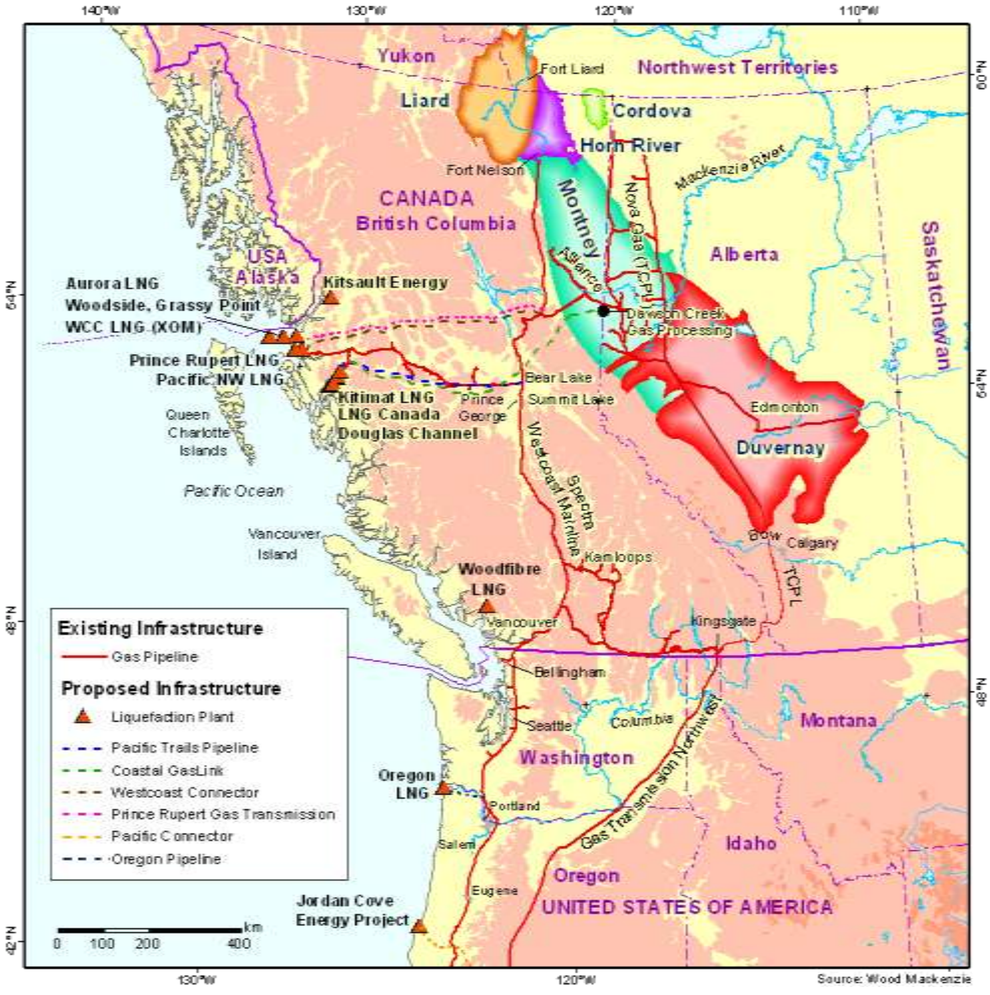
Production from Alberta reached a nadir of 9.4 bcfd in 2013, but with strong growth from a variety of low-cost gas resources production will grow to 10.6 bcfd by 2020 and 11.4 bcfd by 2030. The production mix in Alberta is currently undergoing a dramatic shift from conventional to unconventional sources, as well as increased reliance on liquids-rich gas drilling and associated gas. Associated gas volumes will increase from 1 bcfd in 2010 to 1.9 bcfd by 2020 and 2.1 bcfd by 2025 as growth in the Cardium and Viking more than offset declines from mature oil wells.

Table 2. WCSB production outlook, selected years, bcfd

	2010	2015	2020	2025	2030
Horn River	0.2	0.2	0.3	1.9	2.7
Montney	0.9	4.1	6.4	8.9	8.9
Duvernay	0.0	0.3	1.9	2.8	3.0
Other plays	13.1	9.4	7.9	7.3	7.9
Total	14.3	14.0	16.5	20.9	22.5

A key growth area for Alberta gas production has been the revitalization of Deep Basin gas targets with horizontal drilling technology. These cretaceous-aged reservoirs under development also possess high btu gas, often with associated condensate volumes, which serve to reduce gas development costs. We expect new rich-gas-focused Deep Basin drilling to grow sharply over the next several years, with strong growth in particular from the Wilrich and Bluesky plays. Production from these sources will increase from 0.9 bcfd in 2014 to 2.6 bcfd in 2020.

Chart 5. Major WCSB shales and LNG infrastructure



However, the biggest driver of WCSB growth will be in the major shale plays: the Montney, Duvernay, Horn River and Liard plays. After several years of delineation drilling, the leading companies in the Duvernay -- Encana, Husky, Shell, and Chevron -- have transitioned their programmes to commercial development. We expect volumes of gas and liquids to grow materially over the coming years, supported by highly productive wells in the gas-condensate areas. Duvernay production is expected to grow from 0.2 bcfd in 2014 to 0.7 bcfd in 2016, as wells and gas processing plants currently under development are completed. We expect the majority of volumes from the Duvernay to come from the gas-condensate areas, with limited development in the oil window post-2019. Due to the high well costs we view the lean-gas areas of the Duvernay as non-commercial. Overall Duvernay volumes are expected to reach 2.8 bcfd in 2025.

The majority of current development activity is focused in the southern parts of the Kaybob area, where wells are expected to have gas IP rates of 2.5 mmcfd and recover over 2 bcf, while also possessing a liquids yield of near 200 bbls/mcf. This high yield helps to offset the high costs of Duvernay wells, which are due to both the depth of the reservoir, complexity of completions, and still early nature of development.

British Columbia is expected to experience the most dramatic growth of the Canadian provinces, rivalling Alberta in terms of total production by the end of our forecast period. Production is expected to grow from 3.9 bcfd in 2014 to 5.3 bcfd by 2020, and will accelerate rapidly over the following decade as up to 10.5 bcfd LNG projects enter service by 2030. This production growth outlook is supported by two of the top shales in North America by resource volume, the Montney and Horn River, with additional world-class resource potential being developed in the neighboring Liard shale.

The Montney shale is expected to grow to be one of the top producing shale plays in North America, reaching 9 bcfd by 2025. This concentration of gas production across the Montney is even more pronounced when looking at the top three producing areas of the play, the Northern BC sub-play, where PETRONAS is the leading driller, the Sundown Groundbirch sub-play, with leading drillers Shell, Murphy, and Encana, and the Heritage Liquids sub-play, which has six leading operators. These three sub-plays are expected to produce two-thirds of Montney production by 2025, and will be leading feed-gas sources for proposed LNG export facilities. The majority of Montney gas production in Alberta is expected to come from the Kaybob area, which will grow from 0.4 bcfd in 2014 to 1.3 bcfd by 2020, with total Alberta Montney production being 0.9 bcfd and 2 bcfd, respectively.

The Horn River and Liard possess nearly 150 tcf of combined resource potential. While these plays are at a disadvantage relative to other key unconventional plays in North America due to their lack of infrastructure and distance to market centres, both shales have reported some of the top producing shale wells globally.

Due to the infrastructure challenges and higher operating costs associated with high levels of CO2 in both shales, we expect limited development and production over the medium term, with Horn River volumes declining from 0.3 bcfd in 2013 to 0.1 bcfd by 2016. As the gas markets strengthen toward the end of the decade and LNG project start-up approaches, we expect Horn River volumes to increase to 0.4 bcfd by 2022, and reach 1.8 bcfd by 2030. Liard volumes are expected to ramp-up following the Horn River, as Apache and Chevron have stated 60% of initial LNG volumes are expected to be sourced from the Horn River, with the remainder from the Liard. Liard volumes are expected to reach 0.3 bcfd in 2024 and grow to 0.9 bcfd by 2030.

Associated gas outlook

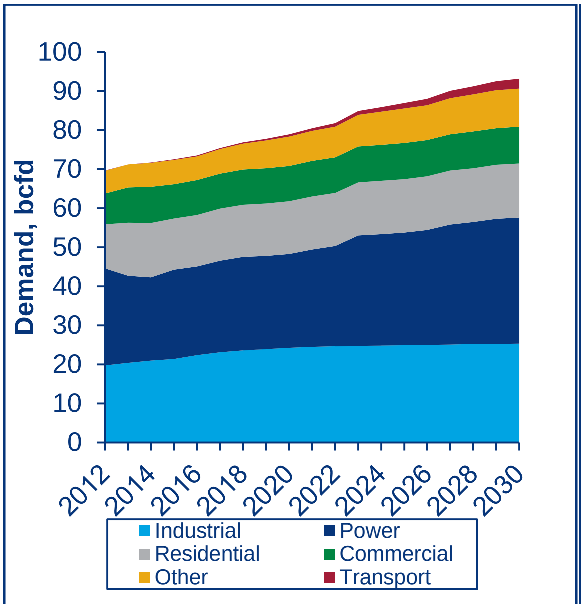
We expect associated gas volumes to grow from 8.6 bcfd in 2014 to 12.2 bcfd by 2020 and reach nearly 14 bcfd by 2025 as the US continues to experience strong growth in oil production from shale and tight sandstone plays. Drilling upside in current oil development, which stands at 1,500 rigs in the US, new discoveries, and potential for further down-spacing, all point to continued upside to tight-oil developments.

The primary growth areas include the Mid-Continent oil plays, the Bakken and Niobrara plays in the Rockies, and long-term associated gas volumes from the Permian. Tight oil drilling programs in the SCOOP and STACK plays in Oklahoma contribute additional low-cost supply to this outlook, but additional investment could add even more production. Other emerging tight oil plays like the Piceance Niobrara and the Pearsall shale offer upside potential. Flaring levels in the Bakken peaked in February 2014, and total flaring is expected to decline to just 0.1 bcfd by 2018, but quicker efforts to reduce flaring could add more gas to the mix. Added associated gas from these plays or others could hold prices Henry Hub prices lower in the midterm.

1.2 North America demand

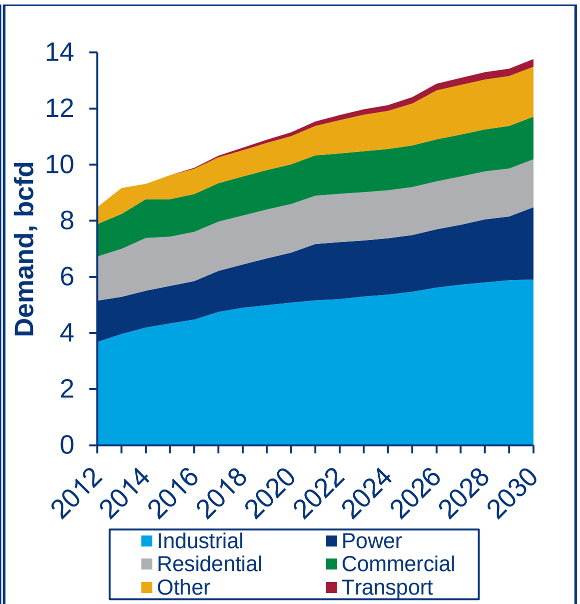
Demand growth can be decomposed in several sectors, each with identifiable underlying drivers of changes in consumption. In this section, we will focus on changes in demand in the power, industrial, and LDC (residential and commercial) markets.

Chart 6. US demand forecast



Source: Wood Mackenzie

Chart 7. Canada demand forecast



Source: Wood Mackenzie

Table 3. US gas demand by sector, selected years, bcfd

	2010	2015	2020	2025	2030
Industrial	18.7	21.4	24.3	24.9	25.3
Power	20.2	22.8	24.0	28.9	32.3
Residential	12.5	13.1	13.5	13.7	13.9
Commercial	8.2	8.8	9.1	9.3	9.4
Other	5.3	6.2	7.5	8.8	9.8
Transport	0.1	0.2	0.6	1.4	2.5

Canada gas demand by sector, selected years, bcfd

	2010	2015	2020	2025	2030
Industrial	3.3	4.3	5.1	5.5	5.9
Power	1.1	1.3	1.8	2.0	2.6
Residential	1.6	1.8	1.7	1.7	1.7
Commercial	1.2	1.3	1.4	1.5	1.5
Other	0.8	0.9	1.0	1.5	1.8
Transport	0.0	0.0	0.1	0.2	0.3

Power markets

After two years of price-induced declines, gas consumption in the power sector returns to the uptrend in 2015. Power burns rise at a 2% CAGR (Compound annual growth rate) through 2020, reaching 24 bcfd. In 2021 we obtain a new high, slightly surpassing the levels observed in 2012, but we do so at a price of $4.72, versus the sub-$3 pricing observed in 2012. From 2020 until the end of the forecast, consumption exhibits a 2.8% CAGR, surpassing the 32 bcfd level in 2029. There are several underlying drivers of this consumption path.

The first is power load growth. We expect electric loads to finally surpass pre-recession levels in 2015, although continued frontloading of cost-effective efficiency gains could further pressure short-term loads. Growth will follow different regional trajectories--Texas and Southeastern loads are expected grow at about 2% p.a., whereas New England and the Northwest will languish at 0.3% growth. Other regions will lie somewhere in between, and the US power market growing to be 12% larger than pre-recessionary peak levels in 2025.

The expected build-out of renewable generation puts downward pressure on gas burns. Supported by the Production Tax Credit extension, we forecast US wind capacity to increase from just below 60 GW at the end of 2013 to about 97.8 GW in 2025. Starting from a North America installed base of about 4.1 GW in 2013, utility scale solar will more than double to 10.5 GW by 2015 as a number of plants exceeding 100 MW in size are completed in California and the desert Southwest. We forecast utility-scale solar capacity to approach 23 GW by 2025, but this number could be higher if costs continue to fall. However, solar without storage provides limited capacity value in most markets. These numbers do not include behind-the-meter residential and commercial installations, which instead manifest themselves as lower utility load.

The EPA's two major air-quality rulemakings of the past half-decade--the Cross-State Air Pollution Rule (CSAPR) and the Mercury and Air Toxics Standards (MATS)--emerged from the courts essentially intact, and are on course to be implemented within the same timeframe, with CSAPR target dates being pushed back three years. Changes in the power fleet targeting the 2016 MATS compliance date will be less dramatic than originally thought, as many operators are choosing to retire coal facilities well before the deadline. We have seen almost 24 GW of plants retire over the past three years, with another 9 GW scheduled for 2014. Next year brings the peak of 22.4 GW, with a further 16 GW following in the second half of the decade. Thus, the ten-year period from 2011 to 2020 will witness nearly 73 GW of coal plants leaving the fleet.

The EPA's Clean Power Plan was released in June 2014, and while is yet to make it through the courts, it looks to have major effects as early as 2020. The EPA plan, instead of establishing an explicit price, sets emission-rate based targets for either 2025 or 2030. The headline target is 30% below 2005 levels by 2030, although goals in terms of gross tonnage remain difficult to nail down. Wood Mackenzie's outlook includes an assumed federal carbon price of $14/mtCO2e starting in 2023, but this is likely less stringent that the eventual federal standards, and therefore there is considerable upside risk to gas burns in the power sector in the 2020s.

Industrial markets

Industrial demand continues to grow through this decade as the gas cost advantage in North America relative to other markets is sustained. With gas prices averaging $4.30/mmbtu through 2020, we expect gas-intensive projects to add 2.5 bcfd of demand while GDP-based growth is expected to contribute a further 1.3 bcfd, for a total of 3.8 bcfd additional demand compared to 2013. In the subsequent decade, growth in large-scale projects will slow down, adding only 0.4 bcfd. On the other hand, GDP-driven growth compensates this by contributing 0.7 bcfd, resulting in additional demand of 1.1 bcfd. All told, through 2031, 4.9 bcfd of new industrial demand will materialize. Key growth industries include agricultural chemicals and fertilizers, methanol, petrochemicals and primary metals processing.

A massive source of growth potential, as yet unrealized, is gas-to-liquids (GTL). We consider Sasol`s $12 billion plant in Louisiana as the most likely project to go forward, but they are still 12 to 18 months away from final investment decision. We expect the initial phase to start up in late 2019, adding 0.2 bcfd of gas demand. This capacity should double by 2020, and possibly triple by 2022. In addition to this megaproject, a number of smaller-scale projects are also on the drawing board. All told, we include seven GTL projects, adding 0.6 bcfd by the end of 2020 in our outlook. Four of these projects are considered small-scale, producing around 100,000 tpy of liquid at most. However there is also an additional 1.2 bcfd of potential gas demand for GTL, based on the early-stage developments by ZeoGas, Energy Security Partners, G2X, and Nerd Gas - US GTL partnership; all of which are massive projects.

Residential and commercial markets

This winter's extreme weather, a one-in-25 cold winter for the US (and a one-in-50 one in the Midwest), caused a 1.74 bcfd uplift to residential and commercial demand for the 2013-'14 heating season, but weather-normalized residential and commercial heating demand has been largely flat for the last 15 years. We expect a slight change in this trend as oil-to-gas conversions take hold, primarily in the Northeast region. Overall, we expect weather-normalized core heating demand to increase from 22 bcfd in 2015 to 23.32 bcfd in 2030. The key risks to this outlook include efficiency improvements through technology or policy mandates, and pipeline construction commitments in the Northeast.

1.3 Domestic and international trade

North American LNG outlook

We expect that eight US Lower-48 and one Alaska LNG export facilities will be exporting 13.5 bcfd by 2030. The US Gulf Coast will see six of these projects, Sabine Pass being first to completion in 2016, with Freeport, Cameron and Corpus Christi coming online by 2020. By 2025, Lake Charles and Golden Pass will bring US Gulf Coast LNG export volumes up to 11.2 bcfd. The US East Coast will see Elba Island and Cove Point coming online by 2020 and Alaska LNG being added post-2026. Wood Mackenzie expects 4.4 bcfd of Canadian LNG exports by 2030 from three facilities: Pacific Northwest LNG, Kitimat LNG and LNG Canada.

Deliverability risks in Canadian LNG export projects, resulting from cost and timing uncertainty, are high as Canadian projects could run into resource constraints due to the remote location, which might be aggravated by competition with oil sands projects. They could also experience challenges in building pipelines across the Canadian Rockies and Coastal Range due to the difficult terrain, environmental concerns, and First Nations resistance.

Cross-border flows: Canada and the US

With more low-cost supply added to the outlook, Canadian exports remain attractive, and total net piped exports increase from 4.7 bcfd in 2014 to 6.5 bcfd in 2025, the increase is short-lived; some supplies are developed ahead of LNG capacity, and once export facilities come online and deliver gas to Asian markets exports drop back to 5.4 bcfd. . The US continues to be the largest gas trading partner with Canada, as the integrated continental pipeline system allows seamless flows across the border.

In the opposite direction, Northeast US supplies continue to increase their market share in Ontario and Quebec through Dawn, Niagara, and Waddington starting 2016, though the ramp-up depends on a number of projects designed to facilitate those flows. Niagara remains the most cost-effective route for Marcellus supplies to access eastern Canada, with imports exhibiting no signs of seasonality even after 510 mmcfd of expansions come online in 2015 and 2016. The Iroquois reversal project will effectively eliminate WCSB's access to almost all northeast US markets except on peak winter days, and imports through Waddington will feed demand growth in Quebec and even downstream markets in New England via Portland Natural Gas Transmission System. Cyclical changes in TransCanada Mainline flows will have some impact on US imports into Dawn, as supplies in Ohio and southwest Pennsylvania are more likely to head south or further west given backhaul and flow reversal projects. Overall, US net imports into eastern Canada via all import points in Ontario and Quebec will rise from 1.4 bcfd in 2014 to 1.7 bcfd in 2025.

Further east, Maritimes Canada has been benefiting from recovering domestic production since the commission of Deep Panuke in late 2013. This play is estimated to peak in 2015. Accordingly, piped exports into US New England region will gradually decline from 253 mmcfd in 2015 to less than 20 mmcfd in 2020, while pipeline utilization increases from Dracut to northern New England post-2020 to accommodate northeast supplies and offset declining Maritimes production. Wood Mackenzie does not forecast flow reversals on the Maritimes and Northeast pipeline as Maritimes Canada demand will be met by domestic production in the long term, but any upside in demand growth could potentially be met by northeast US supplies.

A wave of infrastructure projects, most notably the 1.6 bcfd REX West-to-East project, will allow US Northeast supplies to access Midwest markets starting 2016, adding more supply options to one of the most connected regions in North America. Once threatened by the Marcellus and Utica shales, Canadian exports to US Midwest markets fare better in this outlook given lower WCSB supply costs. More importantly, as gas intensive industries in southern US pull gas from nearby regions, the northeast supplies are more likely to fill the gap left by Gulf and Mid-continent supplies instead of displacing flows from Canada.

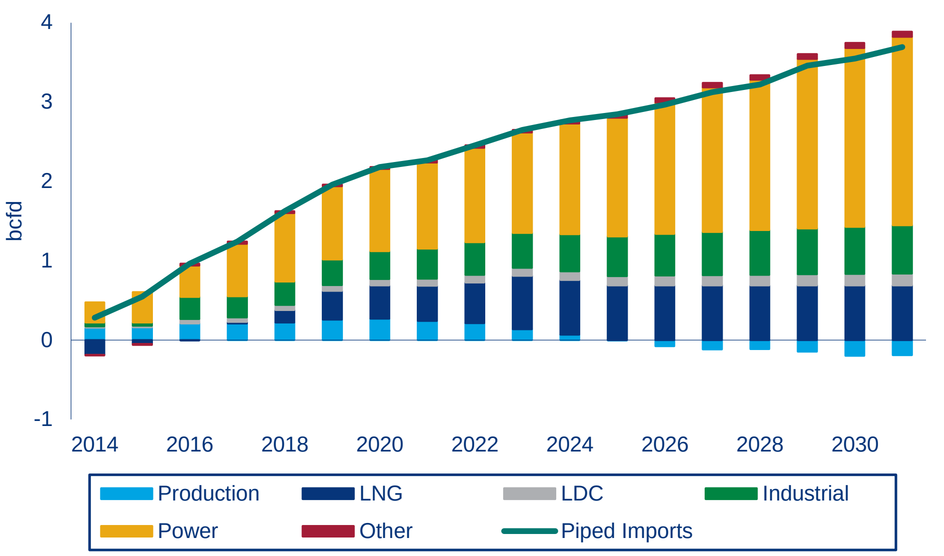
On the other hand, Bakken supplies continue to compete for pipeline capacity as requirements to reduce flaring and growing associated gas production exert pressure on Bakken producers to secure more takeaway capacity. While 0.6 bcfd has already been displaced on the Northern Border and Alliance pipelines in the past six months, proposed industrial projects and coal retirements in the region will entice sufficient WCSB flows to avoid further erosion. Over time, Canadian exports to the Midwest are expected to rise from 3.5 bcfd in 2014 to 4 bcfd in 2025.

Given the proximity to markets and lower breakeven cost, WCSB will edge out Rockies in supplying Pacific Northwest and Northern California markets, with export pipelines expected to run at a higher utilization than today's flow levels. As Rockies supplies head south for higher-value markets in southern California and Mexico, flows on Ruby and Northwest pipelines will experience declining flows from 2014 to 2025, while Canadian exports to western US will rise from 2.3 bcfd in 2014 to 3.9 bcfd in 2025.

Exports to Mexico

With higher industrial and power demand and declining domestic production, piped imports from the US are serving more and more demand in Mexico--as much as pipeline infrastructure in both the US and Mexico will allow. However, in 2011 Mexico's Strategy for Structural Change in the Natural Gas Market outlined a plan, expected to cost more than $10 billion, to construct eight pipelines, adding over 4,000 kilometers of new pipe. In 2014, a second round of new projects was announced, adding five more pipelines, further increasing cross-border capacity and bringing gas to the state of Durango for the first time. These new pipelines are designed to both increase capacity at the border and to improve intra-Mexico connectivity to allow that gas to flow to a number of industries, businesses, and households served by natural gas. Piped gas from the US will eventually grow from 30% of the supply mix in 2013 to 60% by 2023. Mexico's imports from the US are expected to increase from 2.1 bcfd in 2014 to 5.5 bcfd by 2030.

Chart 8. Growth of piped exports to Mexico

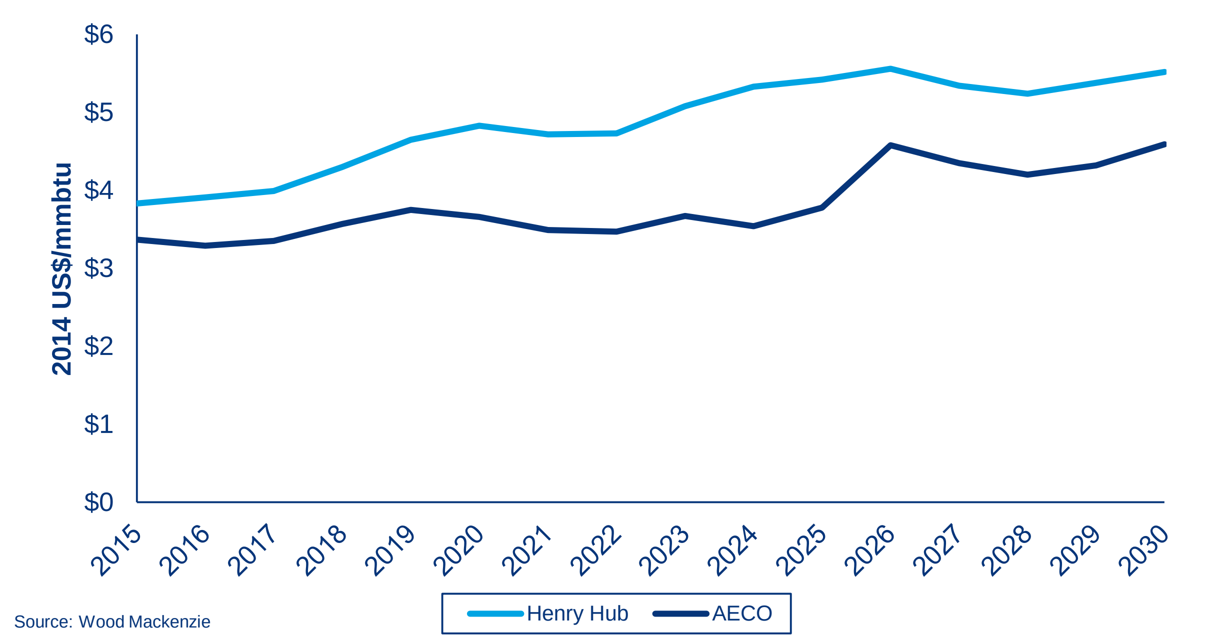


Source: Wood Mackenzie

1.4 Price outlook (Henry Hub, AECO)

The timing of supply growth and new market development defines three distinct periods for Henry Hub gas pricing. Ample low-cost well locations exist to meet the new markets, but not at $4.00/mmbtu through the study period. During the next three years, new production will help refill low storage inventories through the balance of 2014, and by 2015, Henry Hub prices are expected to drop below $4.00/mmbtu. Demand growth accelerates starting in 2016, but the wave of pipeline projects currently under construction out of the Northeast delays any material appreciation in the Henry Hub price until 2018. Between 2018 and 2022, numerous markets compete for shale gas, and this dash for gas pushes up North American gas prices-especially along the Gulf Coast-and spurs a short-lived recovery in coal-fired generation in the East. Annual average prices will climb above the $4.00/mmbtu level in 2018. In the long-term , the low-cost shale resource base can match new markets, but higher prices reflect the need to develop drier areas of rich-gas plays and non-core acreage as well locations in today's sweet spots are exhausted. These higher prices in turn slow the pace of development in gas-intensive industries. Instead, market growth shifts toward transport and power (addressing environmental goals), and these markets support price, infrastructure build, and returns in the upstream. Henry Hub surpasses $5.00/mmbtu in 2023, mainly due to our assumed implementation of federal carbon pricing policy.

Chart 9. Gas price forecast



Source: Wood Mackenzie

Table 4. Gas prices, selected years, 2014 US$/mmbtu

	2015	2020	2025	2030
AECO	$3.37	$3.66	$3.78	$4.59
Henry Hub	$3.83	$4.83	$5.42	$5.52

Henry Hub and AECO price movements are defined by very different market dynamics on opposite sides of the continent, as reflected in notable fluctuations in the AECO basis. Gas prices in western Canada traverse a treacherous path, as low-cost supply growth holds down AECO price appreciation in the near and medium term, and WCSB producers lack access to high-value markets in the south. AECO moves up steadily from $3.37/mmbtu in 2015 to $3.49/mmbtu in 2020 with increased domestic demand and continued export pulls from the US. However, AECO takes a dip between 2022 and 2025, as increased drilling activities in preparation of LNG exports result in a supply surge. AECO breaks $4/mmbtu eventually in 2026 as LNG projects ramp up to full capacity and Canadian market returns to balance to allow meaningful price appreciation. While Henry Hub will have appreciated $1.69/mmbtu between 2015 and 2030, AECO will only have gained $1.2/mmbtu during the same period to settle at $4.59/mmbtu in 2030.

1.5 Infrastructure developments and basis overview

Our long-term outlook is marked by major reversals of historic flow patterns across the eastern half of North America. In the Northeast US, by 2017, inflows decline to zero year-round as outflows increase in all directions. In the Texas-Louisiana area, growth in LNG exports, exports to Mexico, and indigenous industrial and power demand mean that outflows from this area to the north and east drop significantly. Canadian flows to the east drop off dramatically, displaced by Northeast US supply. Canadian gas increasingly flows to the Pacific Northwest and California.

The major underlying theme arising from these changes is that more and more, gas demand will be increasingly served by gas produced in local or adjacent regions. The old story of gas coming from the Gulf Coast, Rockies and WCSB to serve the Northeastern US demand centers is being rewritten by Marcellus and Utica development. The Northeast becomes self-sufficient in gas, and even becomes an export region. Gulf Coast and Mid-Con gas will ramp up to serve rapidly growing industrial and electricity loads in the Southeast and South-Central US, as well as LNG and piped exports to Mexico. WCSB gas will increasingly serve local industrial load, West Coast demand and Pacific coast LNG export facilities.

Most of the under-construction pipe builds are concentrated in the northeast, as takeaway capacity is immediately required to accommodate production growth. 2.6 bcfd is forecast to come online in 2014, with an additional 3.8 and 2.6 bcfd following in 2015 and 2016. Starting in 2017 we expect relief for New England markets, with the arrival of the Algonquin Incremental Market project, followed in 2019 by the Tennessee expansion in 2019. Builds to move Northeast gas further afield, to Southeast, Midwest and Gulf Coast markets, all proceed through 2020.

In the Northeast US, supply-related points trade at a steep discount to Henry Hub. Summer months in particular are vulnerable to major price downside until the Atlantic Sunrise and Dalton projects comes online in 2017 when prices converge as expansion projects continue to push the circle of constrained pricing further out. In particular, the Leach Xpress expansion on Columbia Gas Transmission narrows the Dominion-Appalachia spread; also, the large, 2.1 bcfd Transco Atlantic Sunrise and Dalton projects boost basis at almost all Northeast supply hubs. Longer term, basis declines as supply climbs, and then basis stabilizes as supply levels off. Basis trends at demand centers are more mixed. In the short term the pattern we have seen in the last year continues, with summer prices trading at a discount to Henry Hub and winter prices prone to weather-related constrained pricing. Longer term, summer discounts become more pronounced as Marcellus supply increases, before eventually stabilizing as supply plateaus and demand continues to grow modestly.

Southeast markets balance increased access to Marcellus supply and strong demand growth. Nearly 3.5 bcfd of expansions bringing Marcellus gas to this market, currently one of the most premium in North America, are a bearish basis driver, while growth in gas-fired generation and new LNG export demand at Cove Point and Elba Island support prices. Prices decline from today's levels as pipeline capacity into the region is expanded (particularly the Atlantic Sunrise project in 2017), but once the expansions stop late in this decade, prices will stabilize and even rise slightly as demand grows. However, Southeast basis markets feature upside risk relative to our outlook, particularly in the winter. With the region's growing reliance on gas-fired generation, it may become structurally more similar to constrained markets like New England and New York City, and feature more frequent price spikes.

The Gulf Coast is becoming the demand center of the United States, with strong power demand, increasing industrial demand from both new and existing projects, and over 10 bcfd of LNG export demand expected. Gas supply from near and far is trying to make its way south to access these high-value markets--by 2024, the Henry Hub will be one of the most premium points in North America, trailing only "corner" markets like Algonquin, SoCal, and Transco Z5. The price path of nearby points is related to their proximity to the Gulf, and therefore LNG exports. This region that once was responsible for supplying much of the country with gas is now importing gas from other areas and is the access point to Asia and other foreign, premium markets instead of domestic ones.

Supply growth in the Mid-Continent and Permian basins continues over the next decade, driven by liquids-rich supplies in the Mid-Con and Permian associated gas. Permian basin gas has access to premium and growing markets in Mexico and the West Coast, whereas Mid-Con supplies have to try their luck in the low-growth and supply-crowded Midwest, which leads to a widening of the Permian-to-Mid-Con spread. Mid-Continent prices are in decline, as cheap Marcellus and Utica supplies are pushing west and south, and Mid-Con supply is also growing. We see this supply growth as relatively immune to widening basis, as most of it is liquids-driven.

Midwest prices are in steep decline for most of the forecast period as demand growth is tepid at best. Utica production grows and new pipeline projects push both Marcellus and Utica gas further into the already well-supplied Midwest markets. With gas sourced from a variety of areas, and plenty of pipeline capacity, the area does not generally see the same scarcity pricing observed in eastern markets during extreme weather events like this past winter, although it remains an upside risk--especially with the coal retirements we expect during the next few years.

In the western US, the next four years are likely to feature more of the same, as rising Northeast production and pipeline capacity to take this gas to market crowd out supply development in other, higher-cost regions--including but not limited to the Rockies. Late this decade, rising demand and a plateau in northeast Pennsylvania production mean more marginal supply sources are needed, particularly Haynesville and the Piceance. With growing Rockies production, basis weakens long term, and would weaken much more significantly without a set of pipeline expansions assumed in our outlook.

SoCal basis remains elevated due to support from Mexican demand--exports from the Southwest to Mexico rise by about 400 mmcfd by 2025. SoCal gas will become the premium western basis market by the end of the decade.

Further north, major drivers of our Pacific Northwest basis outlook include Rockies production growth beginning in 2016. The new supplies put downward pressure on basis in the region until 2020. At that point, a small generic Ruby expansion, of 200 mmcfd in November 2020 helps support basis. We also include a 500 mmcfd expansion along the PG&E Redwood Path in January 2017, which narrows the Malin-PG&E spread by $0.03/mmbtu. Sumas basis tightens in 2025, as rising LNG exports in western Canada.

Conclusion

Over the next fifteen years, gas will remain abundant in North America, and supply will have little difficulty satisfying demand in growth at prices below $6.00/mmbtu. The market will grow by 50% over the next decade and a half, with production rising from 80 bcfd in 2014 to 127bcfd by 2030. In the first half of this period, growth is concentrated in the Northeastern US shales, but will diversify regionally over the second half. Demand grows across all sectors, with largest increase observed in the export sector, as LNG goes from zero in 2015 to 18 bcfd in 2030 from facilities located on the Gulf, Atlantic and Pacific coasts. Increasingly, gas demand will be served by supply from local or nearby regions, as the old model of long-haul transportation from production plays to demand centers becomes largely obsolete.

Section 2 - Overview of Regional Markets

2.1 Demand outlook for Quebec and Eastern Ontario

Current state of the market

In order to assess supply sources and pipeline capacity requirements in Quebec, Wood Mackenzie analysed historic and projected demand within the province, as well as market conditions in eastern Ontario and New York and New England markets served through common infrastructure. Because eastern Ontario demand is expected to follow total provincial demand patterns, our report addresses expectations for Ontario as a whole. Quebec and Ontario consumed 3.1 bcfd of gas in 2013, down slightly from 3.2 bcfd in 2003. Combined, the two provinces made up 34% of 9.2 bcfd of total Canadian gas demand last year, compared with 40% in 2003. By 2020, low-cost resource will propel national demand to 11.2 bcfd, and demand is expected to reach 13.8 bcfd by 2030, but growth is concentrated in the west, where oil sands projects require gas and LNG exports leverage proximate regional supplies. Eastern provincial demand does step up; by 2020 and 2030, the two provinces pull an incremental 0.3 bcfd and 0.1 bcfd of gas respectively. The gas serving these markets comes increasingly from eastern supply sources. Short-haul rates on TransCanada under the 2013 settlement bring in supplies from the Marcellus and Utica shales through expanded delivery capacity to the south through Dawn and Waddington, and from the east through Iroquois during the summer. By 2020, eastern supplies are expected to make up 67% of the market, up from 21% in 2013. A delay in the settlement or in New England infrastructure development would mean leave the region dependent on expensive long-haul capacity from Western Canada.

Because Quebec possesses abundant hydroelectric resources, the province does not consume nearly as much natural gas as its counterparts in western Canada; gas makes up less than 20% of the province’s energy use as of 2012. Of the 0.6 bcfd of natural gas demand, more than 55% comes from the industrial sector, specifically in the mining and steel industries, aluminium, petrochemicals, and pulp and paper manufacturing. As a result, the seasonal variation in natural gas demand is not as drastic as in markets where residential and commercial use makes up a larger portion of gas demand. For the last five years, the average peak-month demand in Quebec was roughly 63% higher than the average annual demand, compared to 75% in Ontario, 84% in Manitoba, and only 40% in industry-heavy Alberta.

Ontario, on the other hand, is the second-largest gas-consuming province in Canada, and the largest in eastern Canada. Almost 60% of gas demand in Ontario comes from the residential and commercial sectors, hence the province's more pronounced seasonality in gas demand, varying as much as 3.2 bcfd between winter peak and summer valley. The balance of gas demand is split roughly 2:1 between industrial, concentrated in the refining and petrochemical sectors in Sarnia-Lambton, and power generation, which has been increasing in recent years, as Ontario retires its remaining coal units.

Eastern Ontario makes up roughly 12% of the Ontario market in terms of gas demand, and most of this gas is used for heating. Interestingly, the region features almost a third of total gas-fired generation capacity in Ontario, but the utilization rates for these plants are extremely low, in the 15-25% range. Many plants either have been converted from coal or are old steam turbines that are very inefficient; these plants are unlikely to provide much demand growth going forward.

Chart 10. Provincial energy use by source in 2012

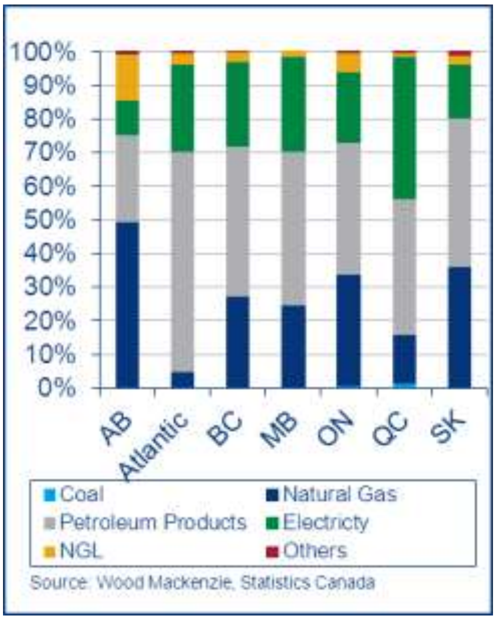
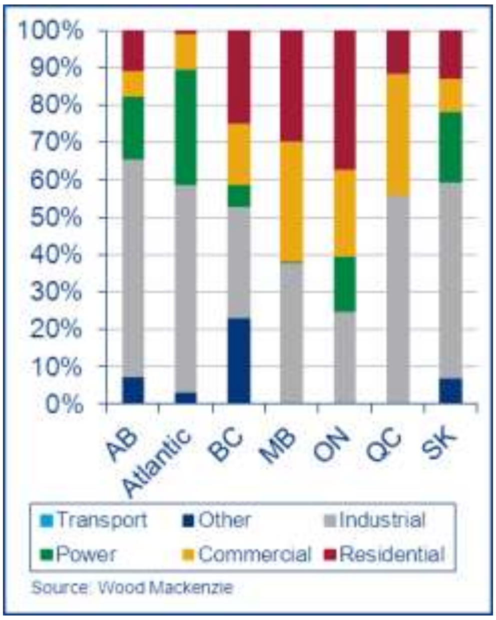


Chart 11. Provincial gas demand by sector in 2014



Demand forecast

Despite near-term setbacks in the Canadian economic recovery, gas demand will grow significantly over the next decade based on resource, industrial and power sector opportunities. The domestic gas market is expected to grow from 9.3 bcfd in 2014 to 13.8 bcfd in 2030, driven predominately by oil sands production and coal retirements mandated by the 2012 federal greenhouse-gas regulations that limit the age of coal plants. However, the regional dichotomy in the gas market becomes more pronounced as demand growth in western provinces is three times as large, in volume terms, as that in the east. Overall, the three western provinces will represent almost 70% of the Canadian gas market by 2030, supporting the long-term revival of WCSB gas production.

Quebec

Regionally, demand growth in Quebec will come primarily from the industrial sector and incrementally the natural gas transportation sector, as the province encourages fuel conversion in long-haul trucking and ferries on the St. Lawrence River. Wood Mackenzie estimates an incremental 155 mmcfd and 31 mmcfd of demand in Quebec in 2020 and 2030 respectively. Industrial demand makes up most of this growth. Overall Quebec gas demand rises at 1.2% CAGR between 2013 and 2030 without the IFFCO plant, or 1.8% with IFFCO.

IFFCO

The Indian Farmers Fertilizer Cooperative (IFFCO), partnering with La Coop Federee of Quebec, has proposed to set up a $1.6 billion urea plant with a production capacity of up to 1.6 million tonnes of urea and 760,000 tonnes of diesel exhaust fluid. IFFCO Canada secured land for the plant at Becancour Port and Industrial Park in 2013, and received construction permission from the Quebec Provincial Government in April 2014. The commissioning of the plant is scheduled for the end of 2017. Wood Mackenzie estimates that the IFFCO plant could consume as much as 73 mmcfd of natural gas, exclusively for their first production phase. Although the project was not included in Wood Mackenzie's Spring 2014 outlook, subsequent progress and approvals raise the probability that the project will come online.

Ontario

Growth potential in Ontario is concentrated in the southern part of the province, with proposed expansions in the petrochemical sector from the likes of NOVA Chemical, and with power demand growing as gas both firms up renewable capacity and replaces nuclear generation in the long term. Long term CAGR for Ontario is 0.4% between 2013 and 2030.

EDA markets

Because of its distance from WCSB, eastern Canada will increasingly look for supplies from nearby markets in the US Northeast. Demand in eastern Ontario and Quebec served through the EOT looks set to climb from 0.9 bcfd in 2014 to 1 bcfd in 2030. The IFFCO plant could add another 72 mmcfd of market. Gas demand in the EDA markets is set to rise at 0.9% CAGR between 2013 and 2030 without IFFCO, or 1.3% with IFFCO.

Chart 12. Canadian natural gas demand (bcfd)

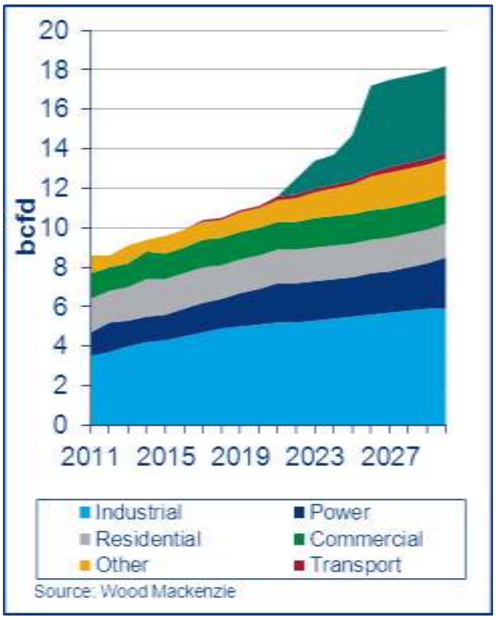


Chart 13. Quebec and Eastern Ontario demand

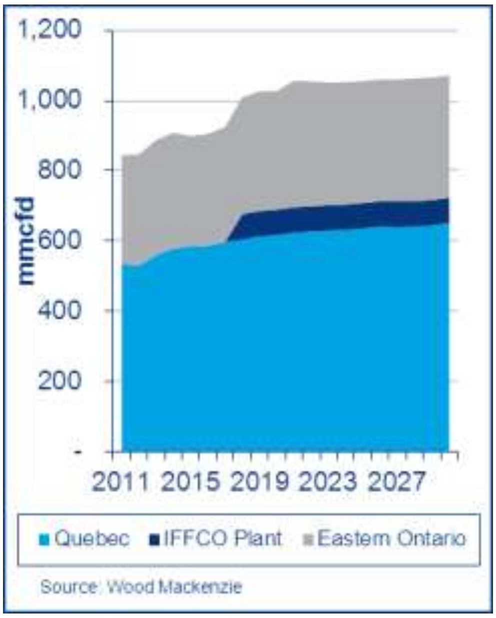


Table 5. Average Demand forecast for Quebec and Eastern Ontario (mmcfd)

	Quebec							Eastern	
mmcfd	Industrial	Residential	Commercial	Other	Transport	**Total**	**IFFCO**	**Ontario**	**Canada**
2011	251	55	212	-	-	**519**	-	310	8,603
2012	267	58	210	-	-	**535**	-	316	8,484
2013	307	56	167	-	-	**530**	-	327	9,174
2014	333	62	166	-	-	**560**	-	331	9,322
2015	325	65	188	-	-	**578**	-	314	9,620
2016	337	62	186	-	-	**585**	-	319	9,888
2017	333	62	185	1	5	**586**	-	328	10,321
2018	341	62	186	1	7	**597**	72	333	10,609
2019	345	61	187	1	10	**604**	72	341	10,889
2020	353	60	188	1	11	**613**	72	338	11,151
2021	353	59	188	1	15	**617**	72	361	11,537
2022	356	59	190	1	17	**624**	72	355	11,767
2023	357	58	191	1	20	**627**	72	350	11,980
2024	352	57	193	1	26	**630**	72	349	12,127
2025	353	56	193	2	28	**631**	72	347	12,410
2026	353	56	195	2	30	**636**	72	347	12,888
2027	355	55	196	3	32	**641**	72	348	13,095
2028	356	56	195	4	30	**640**	72	350	13,295
2029	357	55	194	4	31	**641**	72	349	13,428
2030	356	55	195	6	32	**644**	72	349	13,762

New England call on Waddington supplies

Through Iroquois pipeline at Waddington, EOT infrastructure also serves New England markets. Although extremely high gas prices in New England in winter 2013-’14 in part reflected the cold weather associated with the Polar Vortex, the region nonetheless remains vulnerable to gas price spikes even in the absence of an especially cold winter. Although New England is proximate to the Marcellus shale, limited infrastructure is available to take Marcellus production to New England markets.

Holding the weather constant, we expect this winter to be about 80 mmcfd tighter than last winter because of the impending retirement of the Vermont Yankee nuclear plant. We estimate that, this winter, the New England gas market will be constrained on about 70 winter days, and that imports on Iroquois at Waddington will be near capacity, in excess of 1 bcfd, on these days. In the medium term, New England’s call on imports at Waddington will decline, albeit intermittently. We expect the following fundamental changes:

- **Natural production declines at Sable Island and Deep Panuke** average about 50 mmcfd annually, and **conversions in residential and commercial heating** will add about 25 mmcfd of winter demand annually

- The **Algonquin Incremental Market** project adds 340 mmcfd of gas pipeline capacity in November 2016, but this capacity is only large enough to the aforementioned production declines and heating demand growth, plus the **retirement of the Brayton Point coal plant** in May 2017.

- The 650 mmcfd **Constitution Pipeline**, initially intended to be online in late 2015 but subject to some delays, should decrease New England’s call on Waddington imports by the winter of 2016-’17. Although this project does not add any incremental capacity into New England, it does add cheaper supply to the Iroquois-Tennessee interconnection at Wright, and thereby reduce the call on Waddington imports, all other things equal. We estimate that the maximum call on Waddington imports will decline to about 750 mmcfd, and also that maximum Waddington imports will be needed on somewhat fewer days by winter 2016-20‘17 (in line with 2014-’15 levels, about 70 winter days, after the tightening to about 85 days we expect in 2015-’16).

- **Iroquois has proposed the South to North project**, which would reverse 300 mmcfd of capacity, allowing exports at Waddington. Wood Mackenzie includes this project in our outlook in November 2016, but we do not expect it to be relevant on peak days. During the summer, and on mild winter days, the project would allow cheap Northeast supplies to access eastern Canadian markets, but on constrained New England winter days, this capacity would not change New England’s need for imports at Waddington. This project is unlikely to have a major impact on eastern Canadian basis, as it is small relative to the region’s gas needs even in summer months, and so eastern Canadian prices would still depend on TransCanada economics.

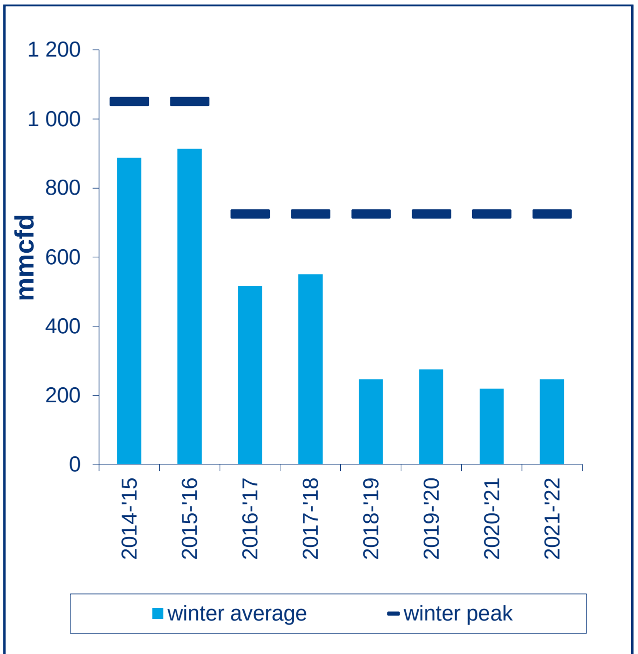
- Given the extremely high prices we expect to persist in New England, and several ongoing regulatory efforts, we model a major gas pipeline to be built into New England in the medium term. In our outlook, we include a 1 bcfd expansion via **Tennessee's Northeast Energy Direct project** from Wright to Dracut in November 2018. An expansion of this size would significantly reduce the number of constrained winter days in New England, to about 10 days of needing maximum Waddington imports.

Although we expect debottlenecking both into and around New England, the timing is subject to significant risk.

- **Constitution** has faced major opposition in New York; however, it is already progressing through the Federal Energy Regulatory Commission permitting process, with a decision expected in January 2015. We see some risk that the project would not be completed for winter 2016-'17, but little risk of its slipping beyond then.

- The timing around **Northeast Energy Direct**, or a different gas pipeline option such as Spectra's Atlantic Bridge, is much less certain. Building a major gas pipeline into New England is predicated either a political alliance (such as the New England States Committee on Electricity) or on regulatory changes within ISO New England that support merchant generators' backstopping gas pipeline capacity development. The former is on hold until this fall's Massachusetts governor's race, while the latter is beset by small balance sheets and disparate interests. New England gas and power prices are so high that we expect new infrastructure to be developed into the region, despite siting and permitting difficulties, but a one-, two-, or even three-year delay relative to our outlook is possible (and indeed, a mild winter could potentially stall development).

Chart 14. Winter peak and average flows on Iroquois Pipeline served through EOT



Source: Wood Mackenzie

2.2 Supply options for Quebec

Quebec and Eastern Ontario access gas supply primarily from the WCSB through the TransCanada system, although Northeast supplies are gaining share within the provinces. Gas is delivered into the region along two main routes:

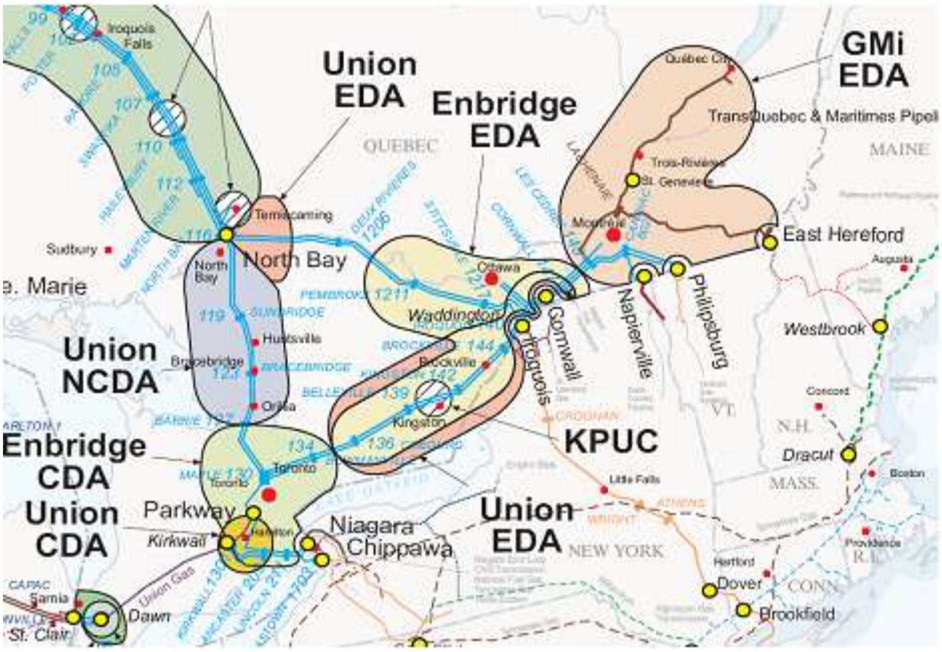
- From the north gas entering the EOT from TransCanada's Mainline at North Bay, is sourced from the WCSB. The western leg of the EOT (The Barrie Line) is bidirectional, and can deliver WCSB gas south from the North Bay junction toward Toronto, or deliver Parkway-sourced gas north.

- A southern supply route into Quebec and Eastern Ontario markets through the eastern leg of the EOT triangle sources gas from Dawn through Kirkwall, and more recently from the Marcellus through Niagara. The supply pool at Dawn includes WCSB gas delivered through the Alliance/Northern Border and Vector systems, the Great Lakes system, along with other US-sourced gas from the Midcontinent and Rockies regions.

As of 2010, WCSB supplied over 80% of the Quebec and Eastern Ontario markets. As of 2013, WCSB supplied 60% of the market.

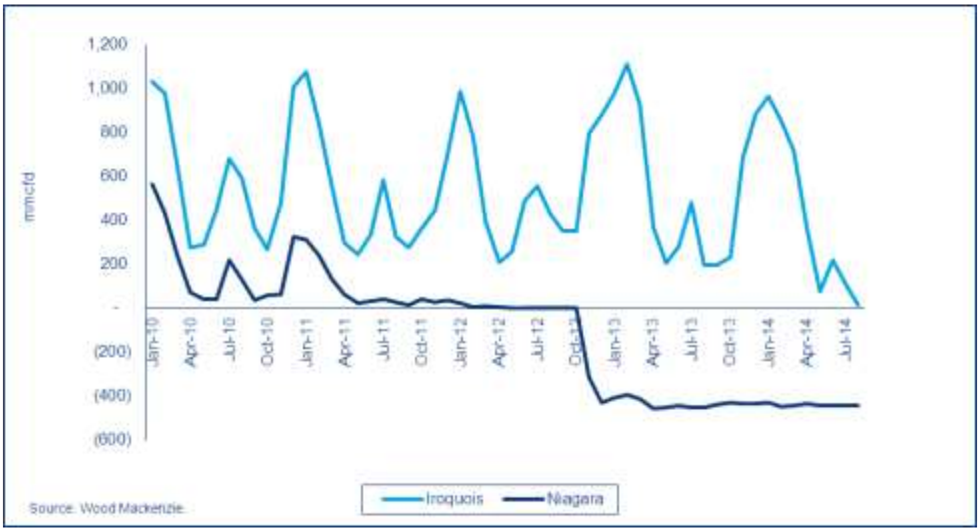
Gas serving the New York and New England areas through the Iroquois pipeline source gas at Waddington delivered through EOT infrastructure. Until 2012, WCSB supplies transited through Kirkwall to Niagara were also exported into New York markets, but changes in demand and the growth in U.S. Northeast supply have led to significant reconfigurations and additions of pipeline capacity to enable Marcellus gas to reach market. Marcellus gas captured markets in Western New York and Pennsylvania, and in November, 2012, capacity on NFG and Empire reversed to allow 450 mmcfd of Marcellus supply to access eastern Canadian markets by flowing North toward GTA and EDA markets at Kirkwall, or flowing south toward the liquid Dawn storage hub. Since the reversal, deliveries at Niagara have averaged 430 mmcfd.

Chart 15. Map of Eastern Canadian Gas Infrastructure



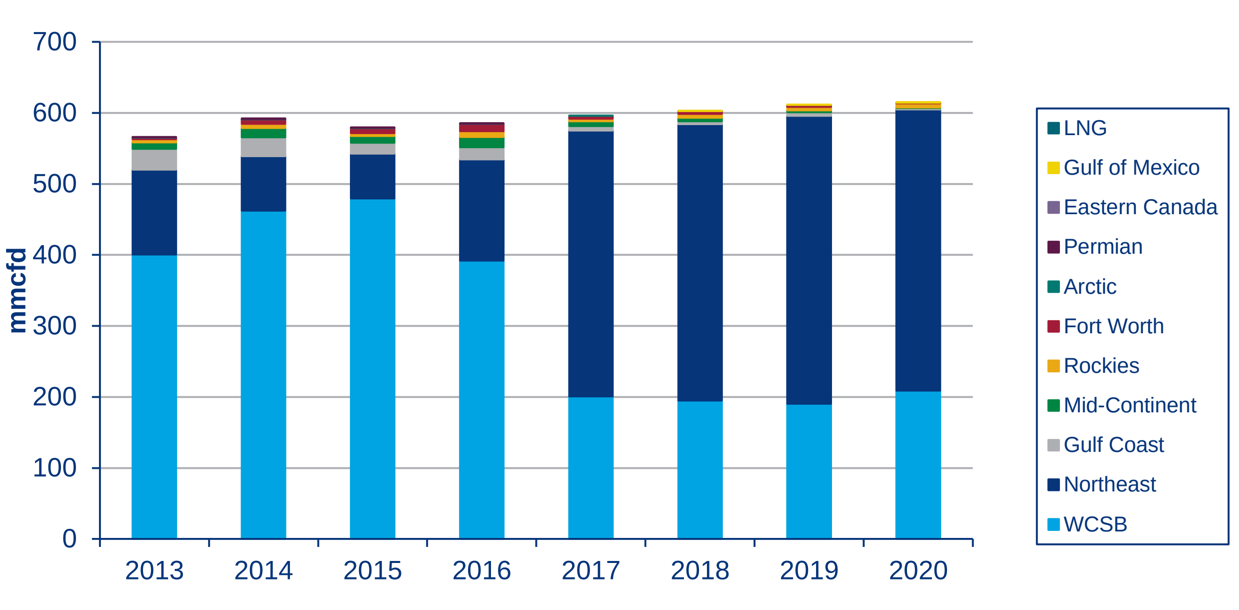
In contrast, Iroquois flows remain seasonally strong because New England markets are constrained during the winter months. Although annual flows on Iroquois in 2013 averaged just 547 mmcfd, flows averaged 867 mmcfd between November 2013 and March 2014, and 1.1 bcfd—compared with 1.2 bcfd of capacity—in January, 2014.

Chart 16. Flows at Waddington and Niagara



The 2012 Niagara reversal shifted the supply mix in the EDA by allowing EDA end-users direct access to burgeoning Marcellus supplies. However, for both EDA markets and New England, Marcellus nonetheless represents only a limited share of winter supplies. As shown in the chart above, TransCanada consistently imports about 400 mmcfd at Niagara, with these supplies almost always much cheaper than other alternatives. But with import capacity limited to about 400 mmcfd, eastern Canadian imports of Marcellus gas will not increase until additional infrastructure is developed, no matter how wide the price spreads are between eastern Canada and upstate New York.

Chart 17. Supply mix in Quebec



Source: Wood Mackenzie

Capacity into EOT, Quebec, Iroquois and TQM markets totals 5.5 bcfd:

- The Northern entrance at North Bay junction offers 3.2 bcfd of total capacity before splitting into the North Bay shortcut and the Barrie Line.
- Along the southern route, gas deliveries into the EOT are constrained by delivery capacity along a TransCanada pipeline from Parkway into Maple. In November 2012, the takeaway capacity between Parkway and Maple was expanded from 1.9 bcfd to 2.185 bcfd, and as of November 2013, capacity was further expanded from 2.185 bcfd to 2.3 bcfd. Despite the expansion, winter deliveries at Parkway track closely to capacity on peak winter days.

Increasing deliverability of Marcellus and Utica supplies—both of which feature vast undeveloped well locations and breakeven prices under $3.50/mmbtu—requires an increase in capacity along the Southern route into EOT. A series of projects, including Enbridge's GTA Segment A pipeline, and TransCanada's proposed King's North pipeline would offer enhanced supply diversity within the triangle by allowing access to productive US shales through Short Haul contract rates. Wood Mackenzie's supply source and price assumptions incorporate online dates for these projects in Nov. 2015, but delays in the regulatory treatment of the Settlement Agreement concluded between TransCanada and the three LDCs in Ontario and Québec, which gave rise to TransCanada's Application now suggest that those dates are too aggressive.

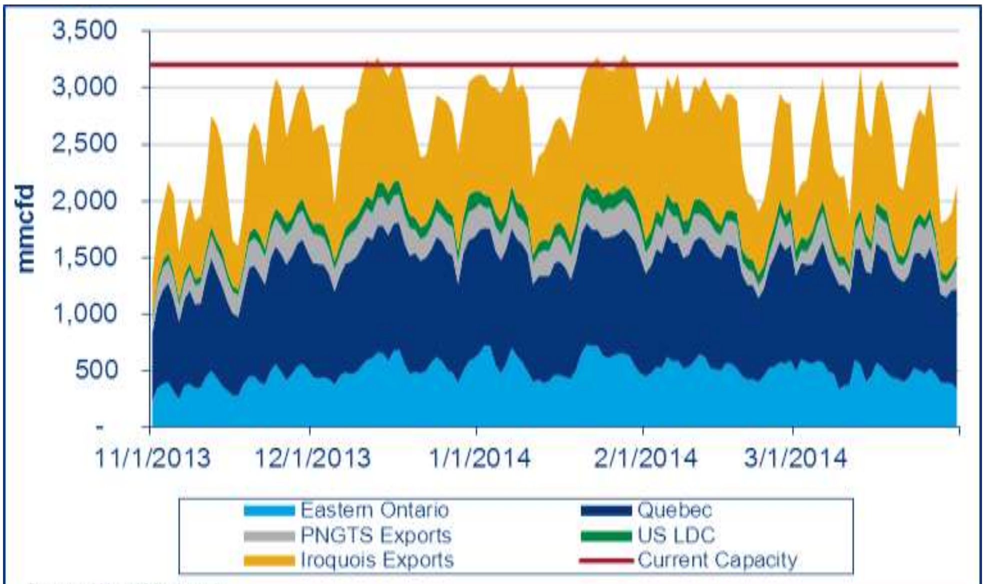
Failure to increase capacity within the EOT and into the EOT has limited the ability of gas consumers in Ontario and Québec to take full advantage of the abundant, economic regional supplies from the U.S. lower 48 states, including the Marcellus and Utica. Without increased access to the Marcellus and Utica supplies, these Wood Mackenzie's forecast import numbers will not be met, requiring the EOT consumers to be more dependent on the more costly, long haul transportation connecting them with the WCSB. This is likely to increase overall costs for these consumers, particularly when load factor adjusted transportation costs to meet heat sensitive seasonal loads are taken into account.

Plays like the Montney, Duvernay, and tight-oil plays like the Cardium that deliver associated gas feature sub-$3.50/mmbtu breakeven prices, and contribute to long-term growth in WCSB production, but supply groth within Western Canada, driven by oil sands and power requirements, present strong regional opportunities, and Pacific Basin LNG export markets represent a high-value market. Transport costs for the supplies into eastern Canada along TransCanada pipeline suggest that eastern plays like the Marcellus and Utica delivered through a combination of short-haul projects and projects into liquid Midwest Hubs represent more favourable long-term options for eastern Canadian consumers. Wood Mackenzie expects long-term basis differentials of minus $0.80/mmbtu at the Dominion South Point in PA, compared with minus $0.90/mmbtu at AECO. With transport differentials into Ontario markets estimated at $0.40-$0.50/mmbtu cheaper from

Dominion South Point than AECO Marcellus and Utica is forecasted to be the preferable long-term options for Eastern Canadian consumers.

In the near term, a combination of project delays and the Energy East conversion could provide challenges for Quebec customers on peak winter day (no additional capacity was available in TransCanada's recent open season, dependence on Constitution and Iroquois reversal).

Chart 18: Capacity at EDA and winter 13/14 deliveries



Source: Wood Mackenzie

Commentary on Winter 2013/2014

- Widespread price pressure across the Midwest resulted from a 1 in 67 cold winter and extremely heavy draws from storage.
- The interruptible pricing framework on TransCanada contributed to upward price pressure on eastern Canadian and Upper Midwest points.
- In all but the most extreme weather cases, most of the Midwest—including Dawn—looks relatively well supplied through 2030.
- However, New England markets are currently constrained for much of the winter, and because of the region's dependence on Iroquois, high import demand and high prices in New England can translate into high prices in Quebec.

Other sources of supply into Quebec

The East Coast of Canada ranks as an important frontier exploration, but regulatory and geologic uncertainty make future production levels highly uncertain. Wood Mackenzie assumes that the resource potential eventually translates into production, and our market outlook includes Quebec Utica shale production starting in 2023 and increasing to 300 mmcfd by 2030. Beginning in 2008, new drilling and completion technologies have resulted in companies investigating the shale gas potential of Quebec, specifically in Utica, an extension of the Utica Shale being developed in Ohio with the most prospective shale beds located within the St. Lawrence Lowlands. In March 2011, the Bureau d'audiences publiques sur l'environnement (BAPE) shale gas review was released by Québec's Ministry of Environment, Sustainable Development and Parks. The report called for the Strategic Environmental Assessment to be imposed but also recommended a controlled pilot drilling programme in order to better understand the commerciality of the shale zones. As a result, the government enacted a five-year moratorium on shale gas exploration and hydraulic fracturing in the densely-populated St. Lawrence Lowlands in 2013.

While the provincial government's stance on shale gas has remained firm with the moratorium, the government allotted Junex the first horizontal oil well permit since the BAPE review in 2011 on its Galt lease near Gaspé, in northeast Québec in July 2014. This signal of regulatory progress is a potential boon for unconventional exploration across the province, though it did take approximately two years for the horizontal section of the well to be permitted. The company has plans for additional horizontal wells in this area, though additional permits are pending. Some operators have indicated that since the release of the BAPE report, public resistance to shale gas development within the province has diminished. However, none of the major operators have yet allocated any capital to further exploration within the play. In the interim, some of the leading Utica acreage holders have since shifted focus to developing the province's conventional oil resources or to other jurisdictions.

While gas fracturing continues to be a politically delicate topic, in April 2014, the province signed an exploration work with Corridor Resources for the Macasty tight oil formation on Anticosti Island. Corridor Resources and partners drilled a series of wells in 2005 and 2010 on Anticosti Island, north of the Gaspe Peninsula. The partners encountered oil shows in several Anticosti exploration wells, and drilling results indicated prospective areas for the Macasty oil shale, but further delineation and testing of the play would be required. Exploration stalled after Apache abandoned the joint effort, but the addition of Resources Quebec and Maurel et Prom as joint venture partners in April 2014 adds momentum to the exploration efforts. In June 2014, Quebec's Minister of Energy and Natural Resources established a prescriptive regime for petroleum, natural gas and underground reservoir exploration activities on lands on Anticosti Island that are reserved to the state. This could very well be a precursor of the framework that may apply to oil and gas exploration activities elsewhere in Quebec.

The approvals of exploratory activities for Corridor Resources in April 2014 and Junex in July 2014 could indicate a potential loosening of permit restrictions around tight oil exploration in less populous parts of the province. Uncertainty looms over how quickly subsequent tight oil permits will be approved, how the environmental opposition in the province might react to the tight oil permitting, and whether restrictions around shale gas will be relaxed. During the summer of 2014, BAPE is slated for a second round of hearings to reconsider the moratorium, as well as additional assessment of the impacts of shale gas development. Regulatory restrictions could be easing over the next two years, with new legislation potentially coming in 2015 to alter the current stipulations to oil and gas exploration in the province. With operators shifting focus to the US side of Utica shales and dramatic production growth in US northeast, Wood Mackenzie has delayed first commercial production from the Utica shale in Quebec to 2024, with production expected to reach 0.3 bcfd by 2030. Regional supplies are not likely to provide any relief for Quebec consumers before 2020.

The geological characteristics of Macasty Formation, and indeed other niche tight oil reservoirs in the eastern Provinces, do indicate strong potential. However, given the mixed well results to-date, Wood Mackenzie does not include a material development outlook in our current commercial view, as drilling campaigns and play-specific technology applications will take years prior to clarity on any development programme. Wood Mackenzie will be tracking exploration efforts, the results of which could shift our view.

2.3 Changing flow dynamics to meet regional demand

Infrastructure developments into Eastern Ontario/Quebec

Ontario was one of the first new markets that Marcellus supplies accessed, given its proximity and relatively easy reconfiguration of TransCanada at Niagara. Wood Mackenzie expects **further expansions in US export capacity at Niagara** in November 2015, and Marcellus exports to Canada will again ramp up in 2016 at the Empire interconnect with TransCanada at **Chippawa**.

Further east, the SoNo project on Iroquois pipeline is expected to allow bi-directional flows at Waddington starting in 2016, in conjunction with Constitution, which takes northeast Pennsylvania Marcellus supplies into Iroquois. The **Iroquois reversal project** could add as much as 300 mmcfd of Marcellus imports into the Quebec market.

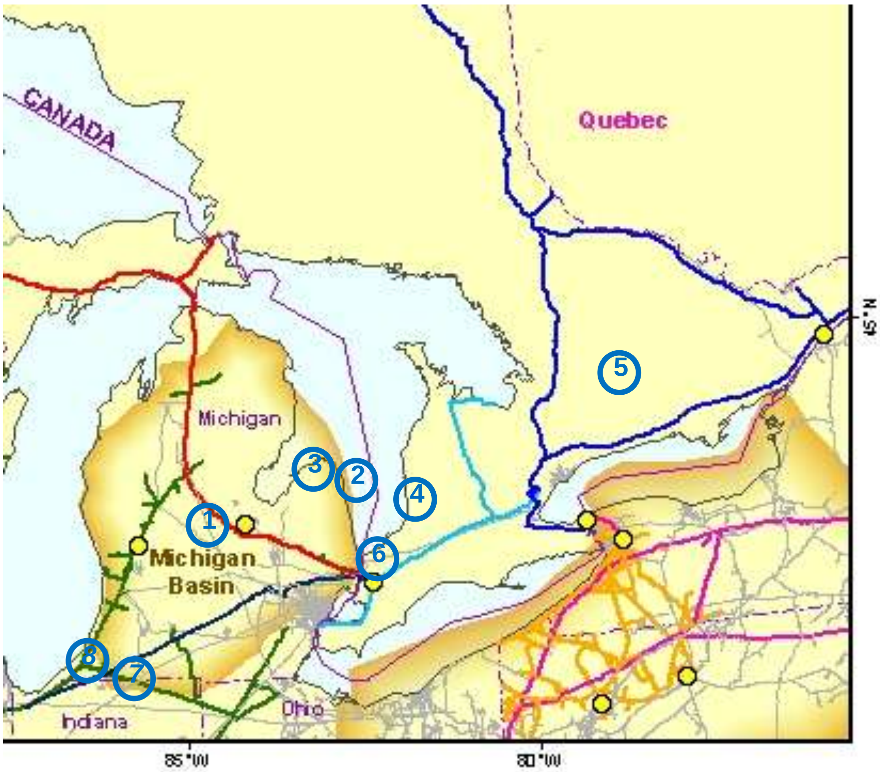
Depending on the outcome of the **TransCanada Application**, a slew of projects in southern Ontario would accommodate additional imports at St. Clair, including the Union Gas Parkway project and Enbridge's Great Toronto Area project, both in 2016, adding a combined 1.8 bcfd of new capacity between Dawn and Toronto. The King's North project, proposed by TransCanada, would alleviate the current capacity constraint between Parkway and Maple, which would benefit downstream markets in the eastern Ontario and Quebec.

Not included in Wood Mackenzie's infrastructure assumptions are **projects upstream of Dawn**, i.e. Nexus or ETP Rover. These projects will compete with other pipeline reversal options that would take Marcellus and Utica supplies to the US South and Midwest. Rover's recently announced (after our base case was complete) customer agreements, totalling more than 2.5 bcfd, make it look increasingly viable, although it is not clear whether this capacity will be built just into the US Midwest or all the way to Dawn. When constructed, these projects would further enhance eastern Canada's ability to access booming US Northeast supplies.

Infrastructure expansions in eastern Canada are concentrated on TransCanada's Eastern Ontario Triangle system, and the added short-haul capacity would provide increased gas supply diversity for eastern Canadian utilities. While pipeline projects around Dawn are tied to the TransCanada Settlement Agreement, its impact would be felt beyond the GTA area, as the capacity constraint at Parkway limits downstream markets' ability to meet winter heating demand with imports into Dawn and Niagara, instead requiring sustained long-haul transportation on the TransCanada Mainline.

Table 6. Proposed infrastructure projects accessing Ontario and/or Quebec

List	Project Name	Proposed Path	In-Service Date	Capacity (mmcfd)
1	Union Gas Parkway Project	Dawn to Parkway	15-Nov	1800
2	Enbridge Greater Toronto Project	Parkway to GTA	15-Nov	1800
3	TransCanada King's North	GTA debottleneck	15-Nov	800
4	Northern Access 2015	US Northeast to Niagara	15-Nov	158
5	Iroquois South to North	New York to Waddington	16-Nov	300
6	Clermont to Chippawa	US Northeast to Chippawa	16-Nov	350
7	*NEXUS*	*US Northeast to Dawn*	*17-Nov*	*2000*
8	*ET Rover*	*US Northeast to Dawn*	*17-Jul*	*2750*



Source: Wood Mackenzie, PennWell MAPSearch

Infrastructure developments beyond Eastern Ontario/Quebec

While almost 2 bcfd of proposed projects are targeted at moving US Northeast supplies into eastern Canada, more projects are proposed that would allow Marcellus and Utica gas to reach the US Midwest, and particularly the South and the Southeast, which are emerging premium markets in North America. Key highlights include:

- **More than 3 bcfd of backhaul projects by 2018 to the US Gulf Coast**, primarily on Texas eastern, Tennessee, and Columbia Gulf. The US Gulf Coast is likely to feature some of the highest prices in North America, because of significant gas demand growth in LNG exports, industry, and power generation, along with a rising call on US exports from Mexico.

- **At least 4 bcfd of capacity being added to the US Southeast**, a combination of backhauls on Transco and Columbia Gas, and potentially new-build capacity. North Carolina consumers Duke and Piedmont recently solicited bids on new-build capacity to the Southeast, and EQT and Nextera are together considering a different potential pipeline project to the Southeast. Southeast gas demand is expected to grow quickly, driven primarily by load growth in the power sector and coal plant retirements, making this an attractive market for producers.

- **More than 2 bcfd of capacity to the Midwest** is already going forward, primarily the reversal of Rockies Express, and additional projects are currently under consideration. Notably, both Energy Transfer's proposed Rover project and ANR's proposed ANR East project feature two options: one targeting the US Midwest, and another extending to Dawn. Although the US Midwest market is not expected to grow as quickly as either the Gulf Coast or Southeast market, the Midwest is relatively proximate to the Marcellus and Utica shales, and features much higher prices. Either or both of these proposed projects could be built without the leg to Dawn.

- **450 mmcfd of capacity to eastern Canada** is expected, including National Fuel's ongoing Northern Access 2015 project, and we also assume a 300 mmcfd reversal on Iroquois in late 2016.

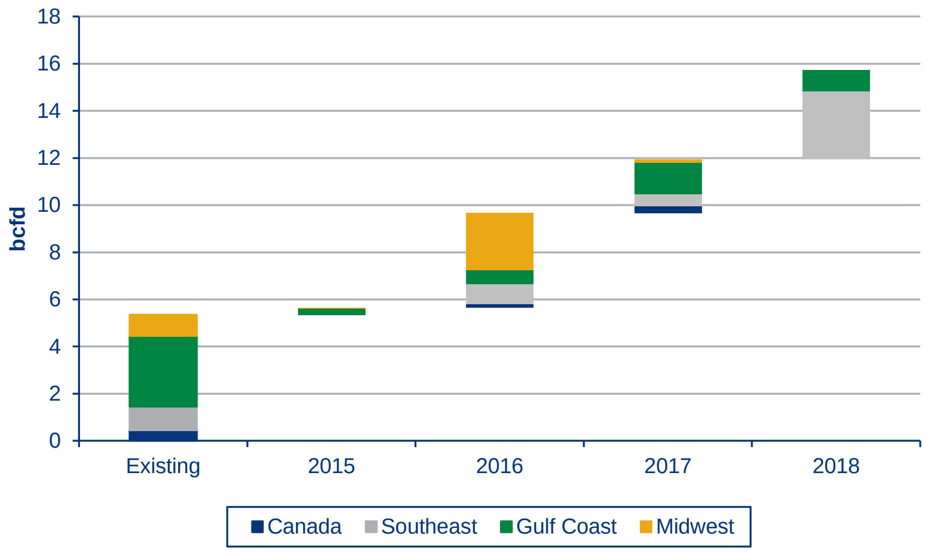
- **Only 340 mmcfd of capacity into New England** is committed, although other projects are proposed. For more information, please see the previous section entitled "New England call on Waddington supplies."

Market access (outside the Northeast) for Northeast supplies

With inexpensive backhaul projects to the Gulf Coast almost entirely exhausted, the next tranche of Marcellus and Utica pipeline capacity will go to some combination of Midwest, Southeast, Northeast, and Canadian markets. Two factors suggest lower gas sourcing costs for end-users that commit to projects sooner: Producers are looking to develop capacity now, so end-users that can share infrastructure development costs with producers would face lower demand charges than if they tried to backstop capacity on their own.

As infrastructure development out of the Northeast grows, the region will become debottlenecked, and regional basis will narrow relative to today's levels and the levels expected the next couple of years. Earlier projects are more likely to feature depressed basis in the supply area, and therefore lower delivered costs for end-users.

Chart 19. Proposed infrastructure projects for Northeast supplies



Source: Wood Mackenzie

With the infrastructure competition to debottleneck the US Northeast, "if more capacity is not made available to move U.S. Northeast production into eastern Canada, the volumes will be committed to other, more distant markets, making it contractually unavailable to consumers within the EOT region. Many of the capacity commitments being made out of the Marcellus are producers looking to sell their gas. Once they have committed to pipeline capacity that moves away from Canada, they will be unlikely to redirect their gas towards Canada until they produce more gas than can fill their committed transportation capacity. Timing is therefore important for Ontario and Québec consumers to access the abundant supply of the Marcellus and Utica shale formations."[2]

Changes in regional flow dynamics

With surging supplies in the US Northeast, Wood Mackenzie's outlook is marked by major regional flow reversals across the eastern half of North America:

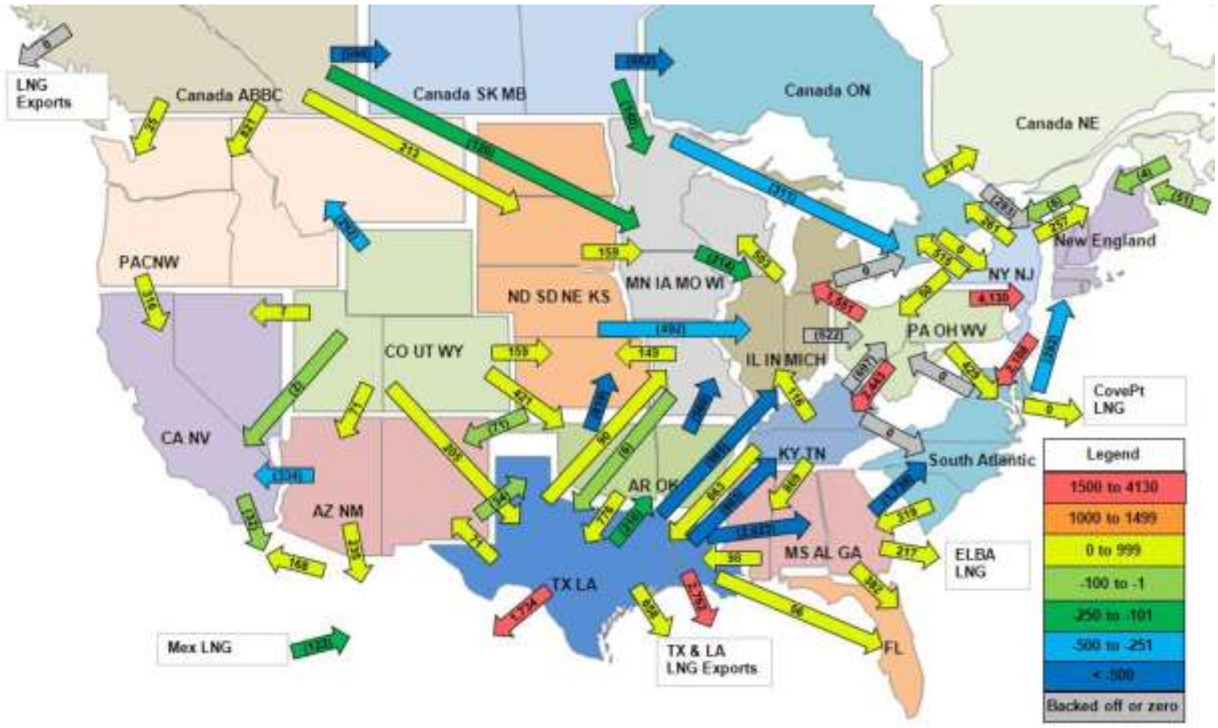
- **In the Northeast:** inflows decline to zero and outflows increase in all directions.
- **In Canada:** Flows from west to east drop off dramatically, with WCSB displaced by Northeast US supply. Canadian gas increasingly flows to the Pacific Northwest.

The map below shows the change in annual flows between groupings of states between 2013 and 2018. The more dramatic changes are in dark blue (large reductions) and in orange and red (large increases). Key flow changes include:

- **Flows from the Midwest to the Northeast**, primarily on Rockies Express, are reversed for a net change of more than 2 bcfd.
- **Flows from the south to north** along the Mississippi—between Columbia, Tennessee, and Tetco—are reversed, with a net change of over 3 bcfd.
- **Flows from the Pennsylvania area east to** New York and New Jersey increase over 4 bcfd with most of this gas ultimately supplying South Atlantic markets.
- The net flow from **New York and New Jersey to Ontario** changes by about 1 bcfd.
- **Flows from the WCSB** to eastern Canada decline by 700 mmcfd as Marcellus imports displace long-haul supplies.
- **Flows from Ontario to Quebec increases by 27 mmcfd to accommodate regional demand growth.**

[2] TransCanada Application for approval of 2013 to 2030 Settlement Agreement, Robert Fleck, Wood Mackenzie July 4, 2014 – page 20

Chart 20. Flow change between 2013 and 2018 (mmcfd)

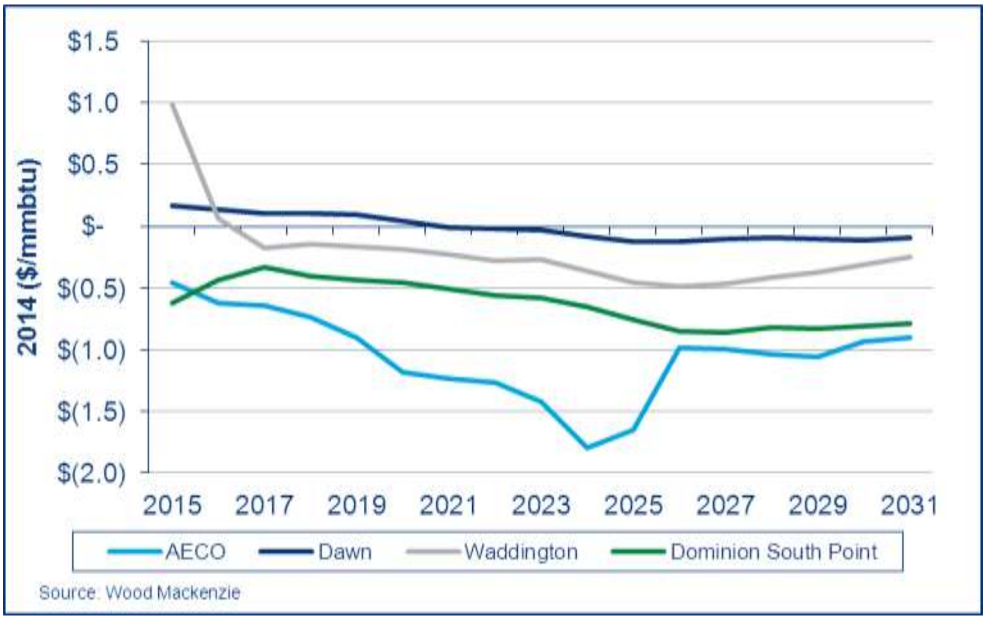


2.4 Regional basis outlook (AECO, Dawn, Waddington)

Maintaining an adequate level of contracting on the TransCanada Mainline in the near term will be critical for eastern Canadian utilities. The existing TransCanada rate structure, with very high rates for interruptible capacity, incentivizes firm long-haul contracts, so we expect eastern Canadian basis to reflect the marginal cost of transportation on TransCanada from AECO. With WCSB supply costs falling, AECO basis is expected to remain weak (albeit not historically so), in the -0.30-0.50/mmbtu range. **Once the TransCanada Settlement becomes effective**, additional pipeline infrastructure in Ontario will accommodate increased supply diversity and higher Marcellus imports into the region, while further debottlenecking the existing constraint between Parkway and Maple. Increasing US Northeast exports to Canada will put downward pressure on Dawn basis and basis further east, and Dawn will lose its premium to Henry Hub by 2021.

For eastern Canada, the cheapest supplies will come from the US Northeast, as is evident already in the extremely high, year-round, utilization rates for import capacity at Niagara. And although eastern Canadian basis will weaken with higher imports, Marcellus and Utica gas also will benefit from additional outlets to help un-constrain the supply region. This modest build-out to Canada, along with infrastructure development to unlock markets in the US Midwest and South, means that Dominion South Point basis will strengthen in the medium term with an improved access to markets.

Chart 21. Basis outlook for eastern Canada (Real 2014 US$/mmbtu)



Conversely, **absent the approval of TransCanada's Application**, eastern Canadian markets would need to continue to rely on long-haul contracts for WCSB supply, and securing the necessary capacity on the mainline would be the priority for supply security and price stability to avoid TransCanada's discretionary pricing structure on interruptible service. Moreover, as the New England markets face chronic winter constraints in the medium term, high New England basis and volatility will spread to eastern Canada as long as Iroquois pulls supplies from Waddington on cold days. In short, eastern Canadian prices will be pulled up by New England prices until *either* new pipeline capacity debottlenecks New England *or* sufficient capacity is built into Iroquois (e.g. an expansion of Constitution or additional pipeline from northeast Pennsylvania to Iroquois) such that demand on Iroquois and deliveries from Iroquois can be satisfied without pulling on Waddington supplies. And without debottlenecking projects in eastern Canada, this basis pressure in eastern Canada could be magnified by capacity limits at TransCanada Maple junction.

With sufficient long-haul contracting and continued dependence on WCSB gas, basis in eastern Canada would reflect AECO dynamics. Even with paying for the more expensive long-haul capacity, (we assume contracting stays around 3.5 bcfd at Empress), Dawn prices remain relatively strong. Under the scenario of no settlement agreement, Dawn becomes a discount point to the Henry Hub in 2023.

Access to eastern Canadian receipt points, using the Settlement tolls, will save natural gas consumers who shift their procurement from long-haul, Empress-based transportation to short-haul, eastern receipt point based transportation (assuming 75% purchased at Dawn and 25% at Niagara/Chippawa) an average of approximately CDN $0.66 per Dth per day in overall landed cost based on a 100% load factor. A consumer utilizing only 80% load factor will save an additional CDN $0.25 per Dth per day in landed cost, for a total savings under the Settlement Toll scenario of CDN $0.91 per Dth per day. These savings are compared to long haul compliance tolls in an environment without access to incremental short haul capacity.[3]

[3] TransCanada Application for approval of 2013 to 2030 Settlement Agreement, Robert Fleck, Wood Mackenzie July 4, 2014 – page 24

Table 7. Price outlook for eastern Canada

Settlement Rate Scenario

Delivered Price

2014 $/mmbtu	AECO	Dawn	Waddington
2015	$3.53	$4.10	$4.05
2016	$3.28	$4.04	$4.02
2017	$3.34	$4.08	$3.84
2018	$3.58	$4.39	$4.17
2019	$3.75	$4.73	$4.49
2020	$3.66	$4.88	$4.63
Average	**$3.52**	**$4.37**	**$4.20**

Compliance Rate Scenario

Delivered Price

2014 $/mmbtu	AECO	Dawn	Waddington
2015	$3.55	$4.08	$3.98
2016	$3.43	$3.99	$3.84
2017	$3.47	$4.03	$3.78
2018	$3.72	$4.35	$4.11
2019	$3.91	$4.67	$4.42
2020	$3.91	$4.82	$4.57
Average	**$3.67**	**$4.32**	**$4.12**

Section 3 – Impact of Energy East

3.1 TransCanada proposed changes

A combination of declining production in the WCSB, increased intra-Alberta demand and increasing production in the US Northeast reduced LH flows along the TransCanada Mainline from 5.2 bcfd to 2.1 bcfd over the past decade. Long-haul contracts dropped from approximately 5 bcfd in 2003 to 1.3 bcfd in 2013 before recovering to 3.5 bcfd in 2014 following the RH-3-2011 decision[4], which approved the compliance tariff on the TransCanada Mainline effective July 2013, reducing the firm long-haul transportation rates, but giving TransCanada greater flexibility for discretionary pricing on short-term firm or interruptible services. Deliveries from Northern Ontario into the EOT declined from 2.9 bcfd to 1.4 bcfd, but capacity utilization within the EOT remains high; flows in the area from the South at Union Parkway ramped up from 0.4 bcfd to 1.3 bcfd at Union Parkway between 2003 and 2013. Given the sustained underutilization of much of its Mainline capacity outside of the EOT, and the surging demand for crude oil transportation out of the WCSB, TransCanada has proposed the Energy East project. As part of Energy East, TransCanada plans to:

- Convert sections of the 42-inch TransCanada Mainline from gas to oil service; and
- Construct the Eastern Mainline project to replace a portion of the converted capacity with a 36-inch pipeline along the eastern leg of the EOT.

Energy East Project

The proposed Energy East pipeline is a 4,500 km oil pipeline system from Hardisty AB to Saint John, NB, capable of transporting up to 1.1 mbd of crude oil with an in-service date of 2018. As part of the project, a 42-inch natural gas pipeline will be taken out of gas service and transferred to the oil business from Burstall, SK to Iroquois, ON. The pipeline transfer will affect existing Mainline capacity on the Prairies Section, Northern Ontario Line, and most importantly, the North Bay Shortcut within the EOT. Wood Mackenzie estimates that the conversion could reduce deliverability in the Eastern Delivery Area (EDA) by as much as 1.2 bcfd.

[4] Due to limited spare short-haul capacity available within the EOT, the EDA end-users needed to contract back to the WCSB and rely on the long-haul capacity to meet winter demand.

Table 8. TransCanada Mainline Capacity[5]

	Capacity (mmcfd)		
	Prairie Section	Northern Ontario	EDA
Existing Capacity	**6,800**	**3,200**	**3,200**
Energy East Conversion	(800)	(1,000)	(1,200)
Capacity post Energy East	**6,000**	**2,200**	**2,000**

Chart 22. Energy East Project Map

Figure 2-14: Existing Canadian Mainline Sections Targeted for Conversion

Eastern Mainline Expansion Project

In order to replace converted capacity in the North Bay Shortcut, TransCanada has proposed the Eastern Mainline Expansion Project in conjunction with the Energy East Project. The project includes a new 36-inch pipeline along its existing Mainline in the EOT from Markham, ON to Iroquois, ON. The scheduled in-service date for the Eastern Mainline Expansion is Q4 2016. TransCanada launched an open season in early 2014 for the project, and Wood Mackenzie estimates that the Eastern Mainline Expansion could replace 600 mmcfd of converted capacity in the initial stage.

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[5] TransCanada to Enbridge Interrogatory #2, EB-2012-0451/EB-2012-0433/EB-2013-0074, August 26, 2013 – page 3-4.

Chart 23. Eastern Ontario Triangle

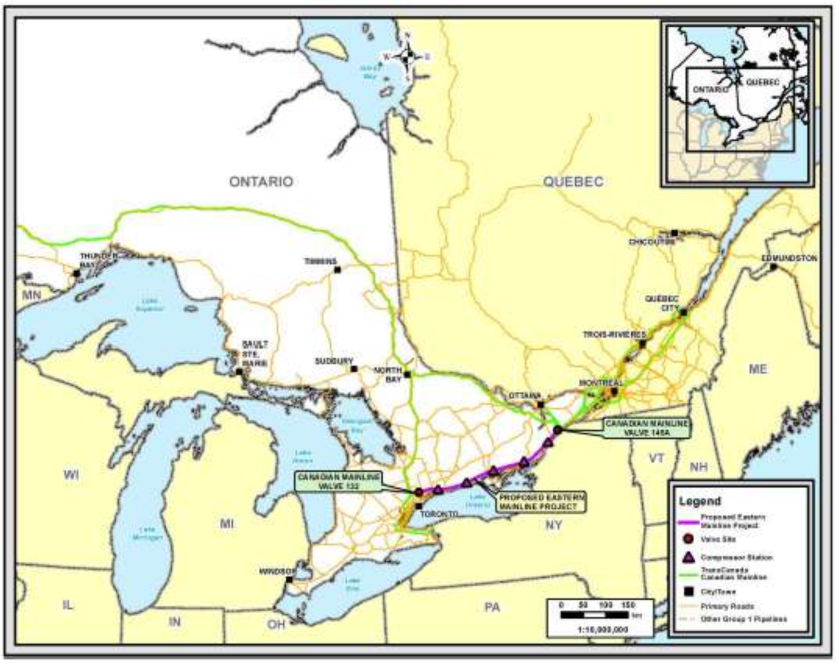


Figure 1-1: Overview Map of Proposed Project

Table 9. Changes in EDA capacity as of November 2016

	Capacity (mmcfd)
Existing EDA Capacity	**3,200**
Energy East Conversion	(1,200)
Eastern Mainline	600
EDA Capacity post Energy East	**2,600**

3.2 Impact on Flows

Based on Wood Mackenzie's assessment of interregional gas flows, the Energy East conversion and Eastern Mainline Expansion will have no material impact on the Prairies or Northern Ontario section of the TransCanada Mainline. After the conversion, the EDA area relies more heavily on Kirkwall deliveries versus Northern Ontario deliveries compared with Wood Mackenzie's base case without Energy East. Although post-Energy East capacity into EDA and downstream markets is adequate to meet average annual and monthly demand, peak winter capacity is constrained into EDA and downstream markets following the conversion, despite the added Eastern Mainline capacity. On cold winter days, when delivery capacity does not match demand on the system, prices must rise in order to balance available supply with demand. In New England, price rise toward oil products, and power generation shifts from oil to gas-fired plants to preserve available gas supply for residential and commercial heating customers. Because oil prices are so high, New England winter prices rise into the $15 to $20/mmbtu. Because EDA markets are served through the same infrastructure as New England markets, prices in Quebec rise toward New England prices on days when capacity is highly utilized.

Prairies and Northern Ontario Section of the Mainline

The Energy East capacity conversion has no material impact on flows out of the WCSB on the Prairies Section of the Mainline. Overall flows remain well below capacity on a monthly basis through 2030; utilization rates average 47% and maximum monthly utilization reaches just 67%. On the Northern Ontario Section of the Mainline, flows average 1.5 bcfd between 2018 and 2030, well below the 2.4 bcfd of capacity post-conversion. Based on supply and storage flexibility in delivery markets served by the Prairies and Northern Ontario sections of the pipe, reduced capacity will be adequate to meet peak day requirements.

Chart 24: Capacity and flows on Prairie Section

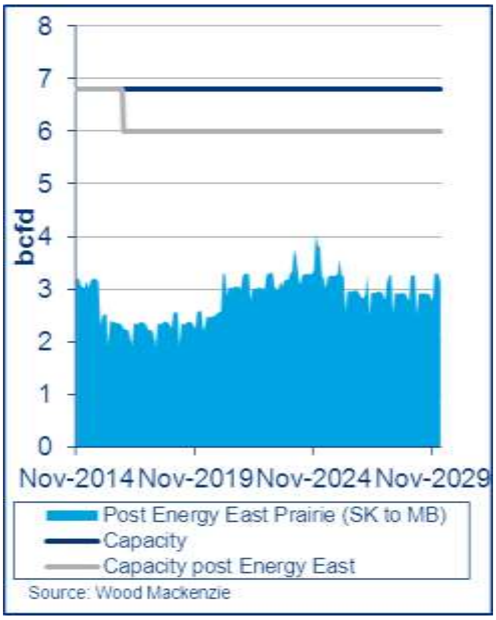
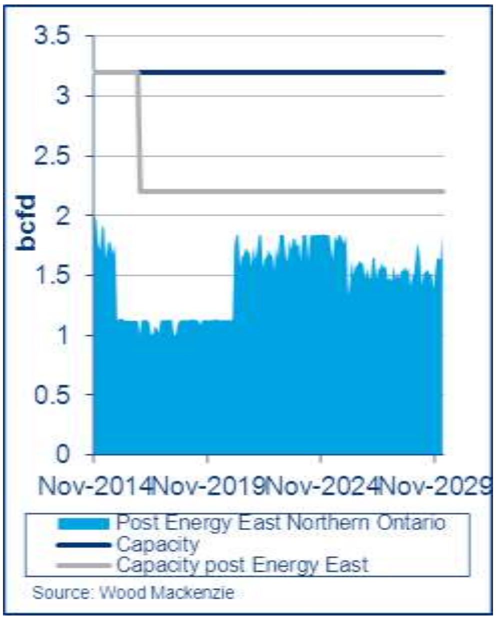


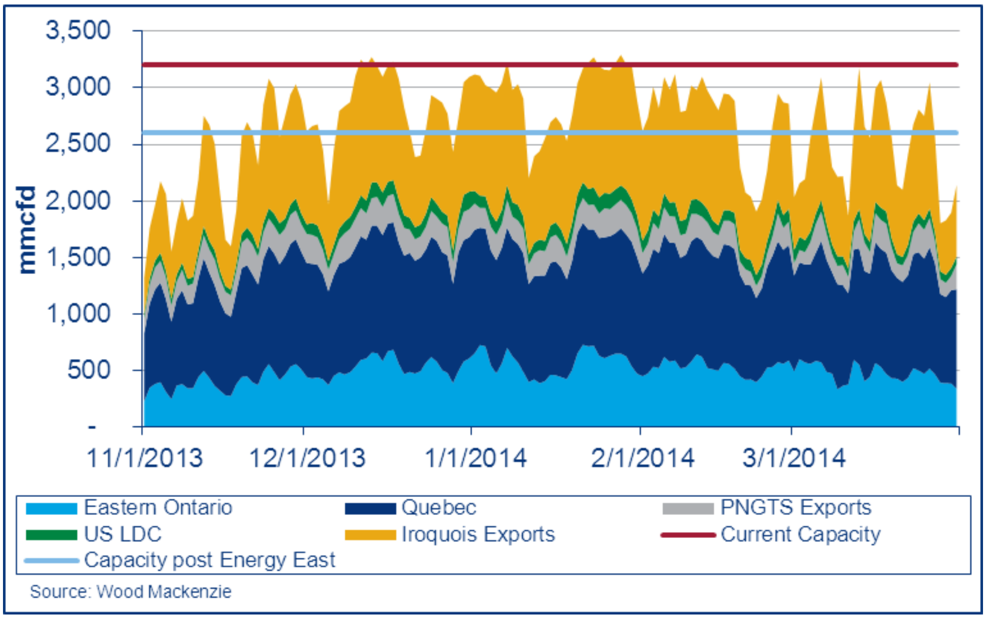
Chart 25: Capacity and flows on Northern Ontario



EDA and downstream markets

During winter '13/'14, extremely cold winter weather resulted in high capacity utilization into EDA markets. Flows averaged 2.7 bcfd compared with 3.2 bcf of capacity. EDA markets consumed 1.5 bcfd of the gas, while 0.9 bcfd flowed through to Waddington for export on the Iroquois pipeline, 0.2 bcfd flowed through to East Hereford for export on the PNGTS pipeline, and 0.1 flowed directly to US LDCs in New York, Vermont and Maine. Deliveries peaked on Jan 28, 2014 at 3.3 bcfd, with 1.8 bcfd consumed in EDA markets, 0.1 delivered to US LDCs, 1.2 and 0.3 bcfd delivered to Iroquois and PNGTS respectively. Prices in New England reflected inadequate delivery capacity relative to demand, and prices moved up to, and above, oil prices in order to shift demand from the power sector away from gas and ration available supplies to heating customers. When capacity into EDA markets couldn't match demand—including Iroquois demand—prices at Waddington shifted up toward high New England prices.

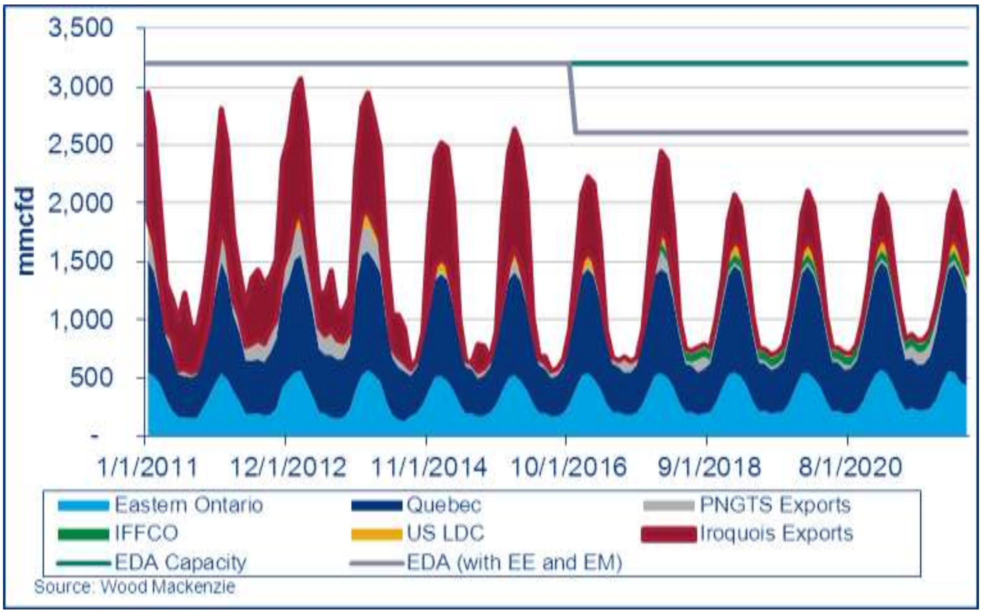
Chart 26. Utilization on EDA and downstream delivery capacity winter 13/14



On 97 days last winter, deliveries exceeded post-Energy East capacity, and average January flow was 2.9 bcfd, 0.3 bcfd above the 2.6 bcfd capacity. However, downstream demand is not likely to reach last winter's levels once Williams' Constitution pipeline comes online. Constitution would deliver 650 mmcfd of low-cost Marcellus Northeast Pennsylvania supply into the Iroquois pipeline downstream of Waddington. Because the new project is expected to flow close to capacity, Iroquois would pull only 725 mmcfd of gas from Waddington on a peak day. That reduced downstream is offset somewhat by higher expected peak day EDA demand growth. In this analysis, Wood Mackenzie assumes that Constitution comes online in November, 2015, but recent permitting challenges in New York suggest delays.

Because of the potential reduced call on gas at Waddington, post-conversion capacity would be adequate to cover monthly EDA and downstream requirements in 2015/2016.

Chart 27. 'Monthly EDA and downstream markets and capacity



Nonetheless, demand on peak winter days do exceed post-conversion capacity starting in winter 2016/2017. On cold winter days, heavy heating loads in eastern Ontario, industrial and heating demand in Quebec, combine with high US exports to surpass the 2.6 bcfd of deliverability available after the Energy East conversion, and on those days, prices in the integrated region will shift up in order to balance available supply with demand. By 2018/2019, demand on 10 days will exceed delivery capacity, assuming Northeast Energy Direct comes online in November 2018. Should the project be delayed, more constrained days would occur. By 2020, demand on 14 days exceeds maximum capacity, and EDA markets will connect with high-priced New England markets. January gas prices at Waddington could exceed Dawn prices by $3.00/mmbtu. Price levels depend on the pace of pipeline debottlenecking into New England.

Chart 28. Peak winter day EDA and downstream markets and capacity

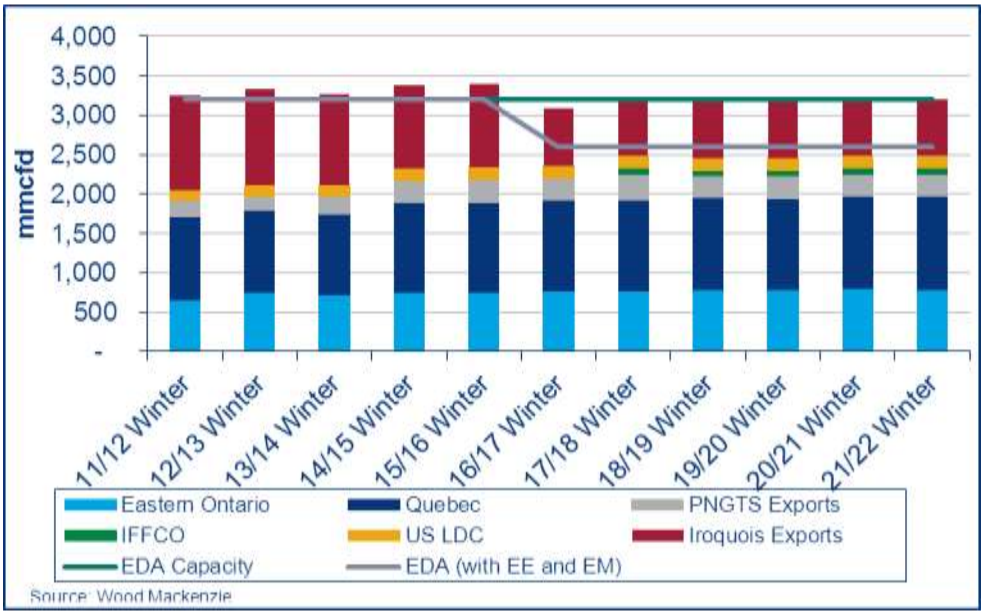


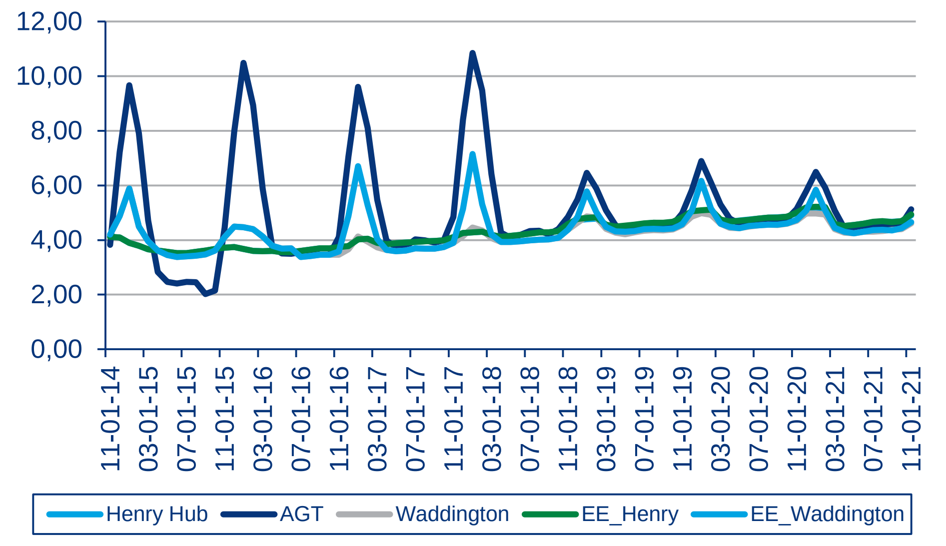
Table 10. Peak day flows for EDA and downstream markets

	Eastern Ontario	Quebec	PNGTS Exports	IFFCO	US LDC	Iroquois Exports
11/12 Winter	665	1,045	211		122	1,204
12/13 Winter	757	1,035	190		125	1,219
13/14 Winter	720	1,030	217		152	1,151
14/15 Winter	757	1,130	282		155	1,050
15/16 Winter	757	1,133	298		155	1,050
16/17 Winter	774	1,149	282		155	725
17/18 Winter	780	1,154	324	72	155	725
18/19 Winter	788	1,165	282	72	155	725
19/20 Winter	785	1,165	282	72	155	725
20/21 Winter	798	1,176	282	72	155	725
21/22 Winter	791	1,181	284	72	155	725

Chart 29. Illustrates the difference in winter pricing between with and without Energy East. The chart also indicates the importance of the timing of New England pipeline projects. Waddington prices decline relative to Algonquin prices in November 2015 when the Constitution pipeline comes online because gas from the Marcellus flows into the Iroquois pipeline and reduces the need for gas delivered to Waddington through the EOT. If that project is delayed, Waddington and Quebec would price closer to Algonquin through the winter. After the Energy East conversion, Waddington and Quebec move closer to New England prices because delivery capacity in the EDA is more constrained. A delay in the Constitution pipeline beyond the November, 2016 Energy East conversion date would threaten system reliability in the EDA and New England regions.

Because the Northeast Energy Direct project into New England is slated to come online in November, 2018, New England markets are not constrained on as many winter days. Significant regulatory and economic hurdles could delay New England debottlenecking. If NED is replaced by a smaller project, such as Spectra's Atlantic Bridge 600 mmcfd project, or if the project is delayed, New England winter prices would remain in the $8/mmbtu to $10/mmbtu range. Assuming NED is online in winter '19/'20, the New England market is constrained on only 7 days, and AGT winter basis would average $0.90/mmbtu. In contrast, without a major new pipeline, New England pipeline capacity falls short of market requirements on 125 days. Constraints would push New England winter basis to $6.50/mmbtu, and integrated EDA markets would price in the $6/mmbtu to $8/mmbtu range.

Chart 29. Winter prices with and without Energy East



Source: Wood Mackenzie

This analysis is based on capacity requirement in Quebec. Should demand decrease significantly, the negative effect of Energy East on the Quebec market would be reduced. Conversely, should demand increase significantly, as forecasted by KPMG-SECOR, the negative effect of Energy East on the Quebec's gas supply would increase.

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