

THE POTENTIAL FOR CANADIAN LNG EXPORTS TO EUROPE

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SUMMARY

Offering numerous ports with the shortest shipping distances to Europe from North America, Eastern Canada has the potential to be a player in the European liquefied natural gas (LNG) market. However, the slower-moving nature of proposed projects on Canada's East Coast, combined with a glut of global LNG liquefaction capacity, means it will likely be difficult for Canadian projects to gain a foothold in the market in the near term. As just one player in the worldwide competitive market, Eastern Canada will face challenges keeping up with faster-moving and lower-cost entrants, particularly those on the U.S. Gulf and East Coasts.

Geography, too, is a double-edged sword for proposed projects in Quebec and the Maritime provinces. While they offer the benefit of proximity to Europe, they are located significant distances from Canada's major natural-gas-producing provinces of British Columbia and Alberta. Further, there are no direct natural gas pipelines connecting proposed projects to supply sources in either Western Canada or the Northeastern U.S. This places these projects at a significant disadvantage relative to projects on the U.S. Gulf Coast. The latter are located in a petrochemical hub, complete with major infrastructure connections to numerous sources of natural gas supply.

Also working against Eastern Canadian LNG development is anti-pipeline and anti-fossil fuel sentiments across the country. These sentiments are slowing Canada's regulatory process and have also contributed to the establishment of moratoriums on hydraulic fracturing in three Maritime provinces. This virtually rules out local supply sources of natural gas for export from Canada's East Coast in the near term.

None of this necessarily means, however, that Eastern Canada's future in LNG exports is doomed. Reason for optimism remains and it centres on indications that European countries are looking to diversify their natural gas supply sources and are prioritizing geopolitically stable and environmentally responsible supplies.

Canada is a world benchmark for that kind of stability, thus making it a dependable, reliable supplier unshaken by whichever way the geopolitical winds are blowing. The kind of stability Canada offers will be key to obtaining long-term LNG supply contracts and the financial capital accompanying them to build pipelines and LNG export facilities.

In 2015 the NEB granted export licenses for six proposed LNG export facilities on Canada's East Coast. Since then, one project was cancelled and the remaining five have repeatedly pushed back their timelines. This has left Canada in a limbo of sorts, but it can extricate itself. Market entry in the 2020s is within reach and aligns with a current opening in the European LNG contract market. Canada must move faster, however, if it is going to compete with the U.S., which currently has two operating LNG export facilities and an additional four under construction. The longer Canada's process, the more likely that, for example, countries in Europe wanting to wean themselves off unstable Russia as a supplier, will turn to the U.S. rather than Canada.

Windows of opportunity continually open and close for entrance to any LNG market. For Eastern Canada to compete in the European market it will need secure supplies of natural gas, and investment and long-term contracts to shore up the financing for building the necessary export infrastructure. For all those things to work in harmony, Canada must pick up the pace and deviate from the status quo or risk losing out entirely.

1. INTRODUCTION

Substantial increases in natural gas production and subsequent low North American natural gas prices have prompted an explosion of interest in exporting natural gas from the U.S. and Canada to higher priced markets in Europe and Asia. Exporting natural gas overseas, however, requires the construction and operation of multi billion-dollar liquefaction facilities to turn natural gas into liquefied natural gas (LNG). These liquefaction facilities are a substantial investment requiring long-term contracts with LNG importers to underpin the financing. There are proposed projects in Canada and the U.S., on both east and west coasts, but so far, only projects in the U.S. Gulf and East Coasts have made successful final investment decisions. The nature of LNG markets – the lumpy nature of contracts and the expense of the infrastructure – means that windows of opportunity for new entrants are opening and closing on an ongoing basis.

For Canada, and Canadian producers, the potential for continued market growth is uncertain as the U.S., once a primary customer for western Canadian-produced natural gas, is now Canada's primary competitor. With this in mind, this paper focuses on the prospects of LNG exports from Canada's East Coast to European customers, in terms of demand in these countries and the competitiveness of Canadian supply. We evaluate the feasibility of Canadian exports to Europe relative to other competitors, and which countries are feasible new markets for Canadian supplies. While many undoubtedly consider Asia to be a better target market for Canadian LNG due to the location of the majority of Canadian natural gas reserves in Western Canada, earlier work has already assessed Canadian competitiveness (Moore et al., 2014). Moreover, European geopolitical tensions and a European desire to diversify natural gas supply away from Russia, plus successful LNG development in the U.S. Gulf Coast that is currently supplying Europe, suggest that Canadian exports are not outside the realm of possibility in the medium to long term.

There are many proposed liquefaction projects around the world, including just over 40 in the U.S., making these projects direct competitors to Canadian projects (U.S. Department of Energy 2018). The longer it takes for Canadian projects to move forward, whether in securing regulatory approvals, long-term contracts with importers or sufficient capital to underpin the investment, the more likely it becomes that other projects will supplant Canadian natural gas supplies. Overall, we find that Canadian projects are likely to have a higher supply cost than their U.S. counterparts. There is potential for Canadian LNG exports, but this market opportunity is not guaranteed.

There are currently five proposed East Coast projects; two in Quebec and three in Atlantic Canada.¹ These projects face a number of challenges, both internal and external. A key area of uncertainty is supply sources for the projects. In particular, natural gas production in Atlantic Canada is projected to decline for the foreseeable future, requiring expanded or new pipeline infrastructure to link the projects to either western Canadian gas production or U.S. shale gas in order to guarantee sufficient supply for domestic demand and exports. The ability of these projects to secure long-term contracts with importers will hinge critically on their ability to demonstrate adequate and reliable supplies of natural gas. Current moratoriums on hydraulic fracturing in Atlantic and Eastern Canada mean supply will have to come from the United States or Western Canada, potentially increasing costs to a point where they are no longer economically feasible, particularly in the case of western Canadian supply. Moreover, the price differential between North American pricing points and European demand centres is relatively small, making the higher cost eastern Canadian projects a less compelling business case relative to already proceeding projects in the U.S.

In Europe, demand for natural gas is largely incremental; the majority of countries with LNG import facilities have well-developed economies with limited prospects for growth. Policy action

¹ There was a sixth proposed project located in New Brunswick, to convert Canaport's existing import terminal to an export facility, which was placed on hold in 2016 (Jones 2016).

to limit emissions from fossil fuels may provide additional opportunities, though this is unlikely to be a strong source of demand growth. However, projected demand for natural gas in most of developed Europe is greater than indigenous supply, with this difference increasing out to 2035. Current contracted LNG volumes for Europe peak in 2019 at over 118 million tonnes, providing an opportunity for new entrants in the medium to long term as these contracts expire. This suggests there is scope for Canadian exports if investors can be convinced the projects are feasible. The viability of Canadian LNG exports to Europe hinge on political influences and timing; specifically, whether European demanders are willing to accept higher-cost LNG sourced from Canada (as opposed to the U.S.) in order to have more diversity of supply. It is an open question whether geopolitical concerns will interfere with European supply of natural gas from Russia, the Middle East or Africa, and whether these concerns will prompt additional action to maintain security of supply in Europe.

The remainder of the paper proceeds as follows. First, we detail the structure of European natural gas markets, including consumption, production, existing infrastructure and a demand outlook to 2035, providing perspective on the potential magnitude of LNG imports. Readers familiar with European trends can safely skip this section. Second, we outline Canada's capability in supplying natural gas as LNG to Europe, providing an overview of current production and exports, available infrastructure and an outlook of Canadian supply to 2040. This provides important context and understanding of the physical feasibility of supply. Third, we discuss Canada's potential as an LNG supplier, including a discussion of expected costs and competitiveness. Finally, we detail the policy implications of an LNG industry expansion in eastern Canada, and draw final conclusions.

2. EUROPEAN NATURAL GAS MARKETS

Overview

Natural gas demand in Europe significantly exceeds supply, leaving the region highly dependent on imports from external sources. Although aggregate demand for natural gas in Europe is declining, production is also on a downward trend. Specifically, from 2005 to 2015 aggregate demand for natural gas fell by 18 per cent while aggregate production of natural gas fell by 20 per cent (IEA 2016e). Looking ahead, the rate of decline in aggregate demand for natural gas is set to slow down or perhaps even reverse as countries look toward increased use of natural gas as an option to fulfil climate commitments, and as developing countries in Eastern Europe continue to industrialize. European production, in contrast, appears set to continue a steady decline. The International Energy Agency's (IEA) forecast for Europe shows a strongly increasing wedge between production and demand out to 2040 (IEA 2017; Winter et al. 2018). As a result, Europe will be increasingly dependent on imports of natural gas for the foreseeable future.

The majority of Europe's natural gas imports are delivered via pipeline. While current pipeline infrastructure is capable of supporting projected demand in Europe, many of the source countries have associated geopolitical or social uncertainties. This has created concerns around the stability of Europe's pipeline supply of natural gas and has led to an increasing interest in diversifying toward LNG. This section will consider trends in natural gas demand and supply in Europe and will discuss the likelihood of Europe transitioning toward greater demand for LNG.

Definition of the Study Area

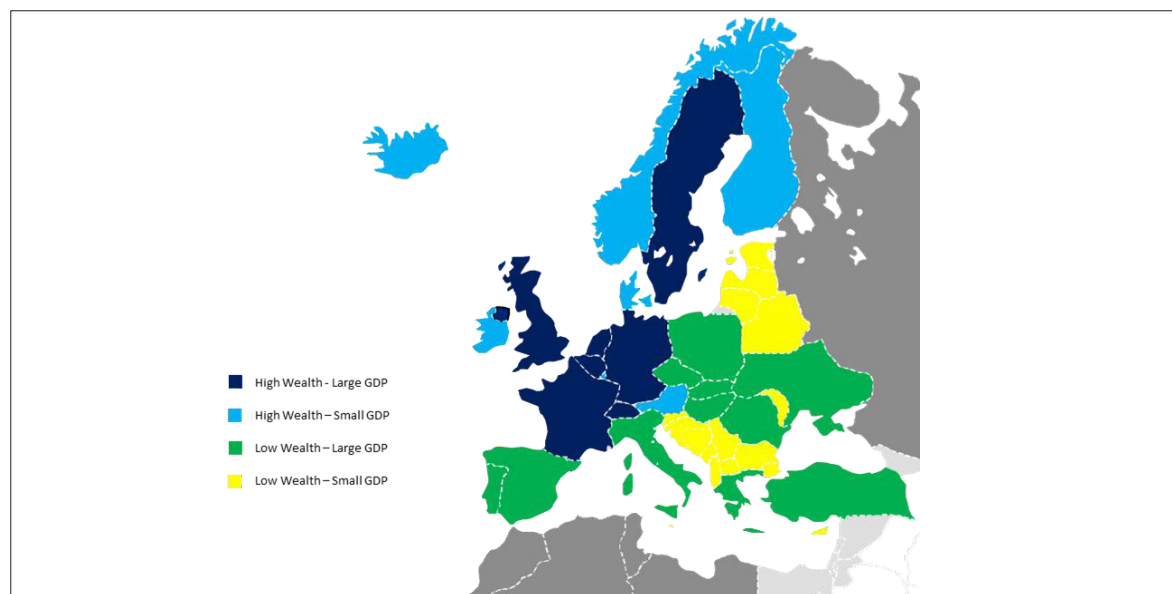
In its broadest definition Europe includes countries in both continental Europe and Eurasia. We define Europe to include countries that are located to the west of Russia. This includes all of the

countries in continental Europe and a small number of Eurasian countries.² This region is a net importer of natural gas and has a large number of ports where LNG imports can be accepted. We exclude from our study area Russia, as well as Eurasian countries that are located to the south of Russia.³ These countries are net exporters of natural gas and have limited port access. They are therefore unlikely candidates for LNG imports.

Our study area (hereafter “Europe”) can be divided according to numerous geopolitical, economic and geographic definitions. These include the European Union, the Eurozone, OECD Europe, the peninsulas (Balkan, Iberian, Appenine and Scandinavian) and regions (Baltic, British Isles, Nordic, Alpine and Mediterranean). We opt not to adopt any of these conventional regions or definitions in our analysis. Rather, we divide our study area according to two significant determinants of natural gas demand – economic wealth and size of the economy. We approximate economic wealth by gross national income (GNI) per capita and measure size of an economy by gross domestic product (GDP).

Current natural gas consumption is typically increasing in both economic wealth and size of an economy. We therefore expect larger and richer countries to have higher levels of natural gas demand than smaller and poorer countries. Both factors also provide an indication of likely future demand for natural gas, although in this case future demand is likely inversely related to current wealth and positively related to size of the economy. In particular, a lower income country with a large economy will generally have the largest opportunity for natural gas demand growth. In contrast, a high-income country with a small economy will likely have the smallest opportunity. For the purposes of our analysis we divide the countries in our study area into four categories – high wealth-large GDP, high wealth-small GDP, low wealth-large GDP, and low wealth-small GDP (Figure 1 and Table 1).

FIGURE 1 COUNTRY CLASSIFICATIONS IN STUDY AREA



² Specifically, countries included in continental Europe are Albania, Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, Macedonia, Malta, Montenegro, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey and the United Kingdom. Eurasian countries included in our study region are Belarus, Estonia, Latvia, Lithuania, Moldova and Ukraine. Kosovo is excluded from Europe due to a lack of available data on natural gas consumption, production and trade. The classification of countries to Europe or Eurasia follows the U.S. Energy Information Administration’s classification in its International Energy Statistics database.

³ Apart from Russia, Eurasian countries that have been excluded from our study region are Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

TABLE 1 CLASSIFICATION OF EUROPE BY 2014 GDP AND GNI PER CAPITA

Classification	Country	GDP (million \$USD)	GNI Per Capita
High GNI Per Capita, Large GDP	Germany	\$3,879,277	\$48,968
	United Kingdom	\$2,998,834	\$45,807
	France	\$2,839,162	\$43,262
	Netherlands	\$879,635	\$52,022
	Switzerland	\$702,706	\$86,648
	Sweden	\$573,818	\$60,224
	Belgium	\$531,762	\$48,041
High GNI Per Capita, Small GDP	Norway	\$498,340	\$101,629
	Austria	\$438,376	\$51,427
	Denmark	\$346,119	\$63,476
	Finland	\$272,463	\$50,342
	Ireland	\$256,271	\$47,099
	Luxembourg	\$64,874	\$77,660
	Iceland	\$17,036	\$52,000
Low GNI Per Capita, Large GDP	Italy	\$2,149,814	\$35,149
	Spain	\$1,381,342	\$29,598
	Turkey	\$798,782	\$10,199
	Poland	\$545,159	\$13,836
	Greece	\$236,080	\$21,619
	Portugal	\$230,117	\$21,760
	Czech Republic	\$207,818	\$18,410
	Romania	\$199,493	\$9,893
	Hungary	\$139,295	\$13,402
	Ukraine	\$133,503	\$2,909
	Slovak Republic	\$100,761	\$18,267
Low GNI Per Capita, Small GDP	Belarus	\$76,104	\$7,776
	Croatia	\$57,136	\$13,207
	Bulgaria	\$56,732	\$7,785
	Slovenia	\$49,530	\$23,964
	Lithuania	\$48,354	\$16,291
	Serbia	\$44,211	\$5,950
	Latvia	\$31,323	\$15,666
	Estonia	\$26,214	\$19,649
	Cyprus	\$23,308	\$19,463
	Bosnia and Herzegovina	\$18,524	\$4,888
	Albania	\$13,220	\$4,514
	Macedonia, FYR	\$11,319	\$5,351
	Malta	\$10,738	\$24,283
	Moldova	\$7,983	\$2,477
	Montenegro	\$4,588	\$7,476

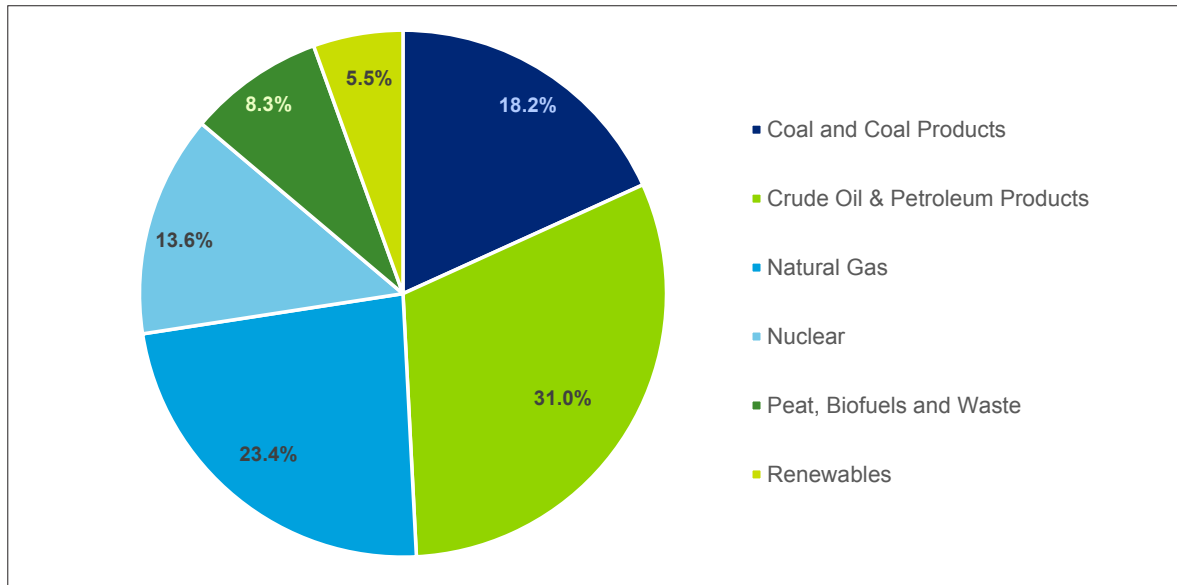
Source: World Bank (2017c).

Note: The threshold for high GNI per capita versus low GNI per capita countries is \$38,000 (approximately equal to the OECD average of GNI per capita from 2014). For high GNI per capita countries the threshold between large and small GDP is \$500 billion and for low GNI per capita countries the threshold between large and small GDP is \$100 billion. GDP and GNI per capita are both from 2014. The GDP series is "GDP (current US\$)" and GNI per capita is calculated using the series "GNI (current US\$)" and "Population, total."

European Natural Gas Demand

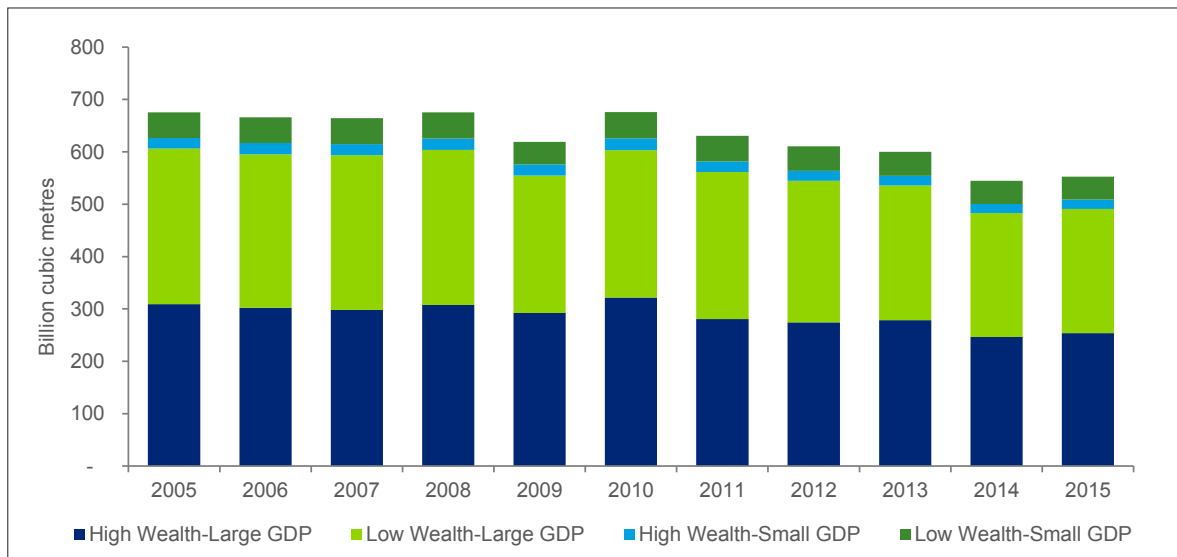
As shown in Figure 2, natural gas accounts for 23 per cent of Europe’s total primary energy supply, making it the second largest contributor behind crude oil and petroleum products to Europe’s energy mix (IEA 2016c). The majority of Europe’s natural gas consumption is shared among the residential, electricity and heat generation, and industrial sectors, which respectively accounted for 26, 31 and 21 per cent of Europe’s total natural gas consumption in 2014 (IEA 2016c).

FIGURE 2 EUROPE TOTAL PRIMARY ENERGY SUPPLY, 2014



Source: International Energy Agency (2016c).

FIGURE 3 NATURAL GAS CONSUMPTION IN EUROPE



Source: International Energy Agency (2016e).

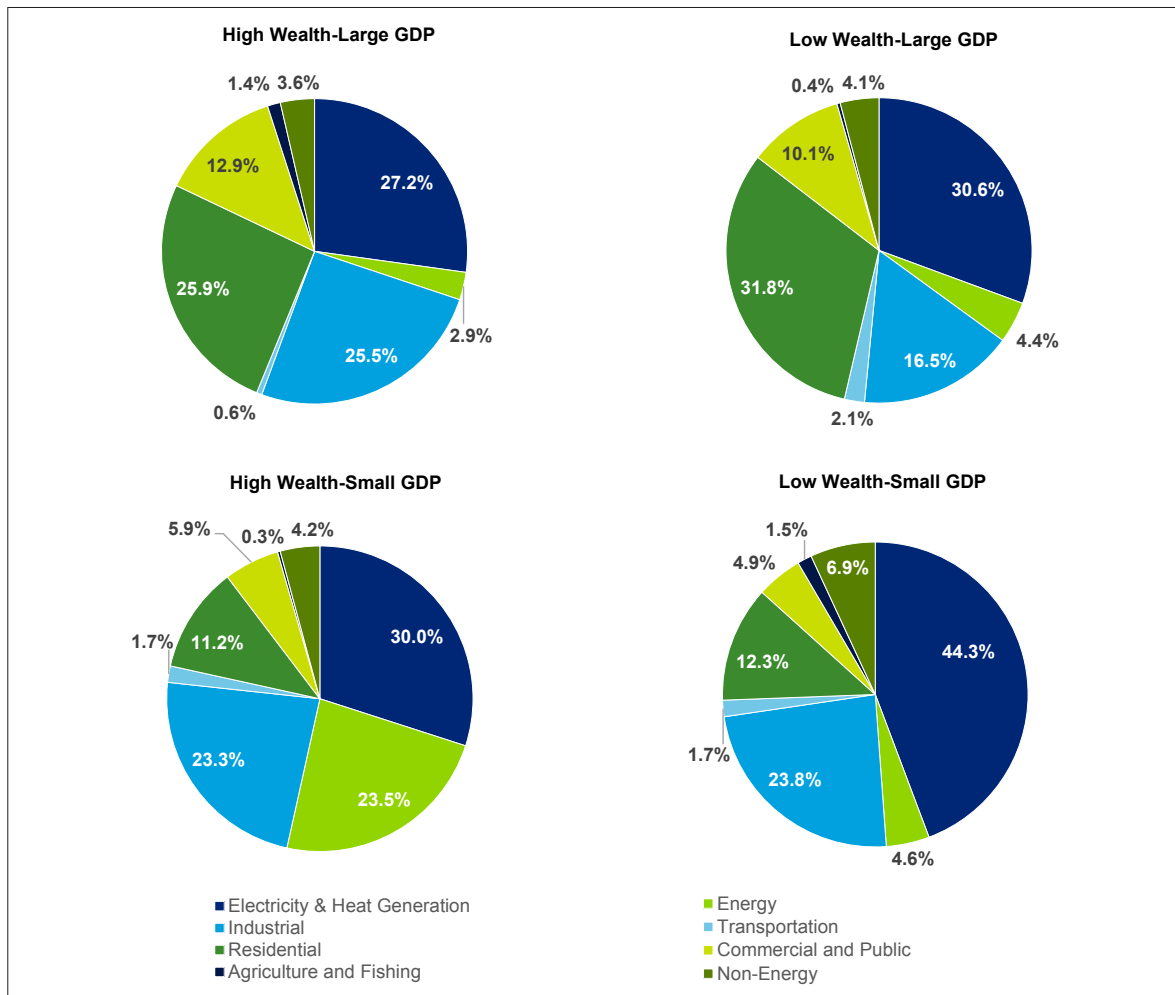
European natural gas demand fell by 18 per cent from 2005 to 2015 (Figure 3). The decline in demand has been driven primarily by falling natural gas consumption in the electricity and heat generation sector. This trend is largely attributable to increased energy efficiency in both the residential and industrial sectors, which is contributing to a decrease in European electricity demand. Additionally, Europe has observed a significant increase in its consumption of renewable energy (Jones, Dufour and Gaventa 2015). Specifically, the share of renewables as a portion of Europe's total primary energy supply has been steadily increasing over the last decade, rising from 3.0 per cent in 2005 to 5.2 per cent in 2014. The majority of this supply is being consumed either directly in the electricity and heat generation sector, or in the residential and commercial sectors, primarily as a substitute for traditional electricity and heat that are supplied by fossil fuels (for example, residential homes and commercial businesses with solar panels and geothermal in place of grid-sourced electricity and natural gas heating).

The trend of declining natural gas consumption has been observed in all areas of Europe. During the steepest period of decline from 2010 to 2014, consumption of natural gas in high wealth-large GDP countries fell at an annual average rate of 6.4 per cent and high wealth-low GDP countries saw annual average declines of 6.0 per cent (IEA 2016e). In contrast, the annual declines in natural gas consumption in the low wealth-large GDP and low wealth-small GDP countries averaged 4.2 and 3.4 per cent respectively.

Large GDP countries accounted for 89 per cent of European natural gas consumption from 2005 to 2015, with high wealth countries accounting for 46 per cent of consumption and low wealth countries accounting for 43 per cent (IEA 2016e). These proportions were virtually constant over the course of the decade. In contrast, high wealth-small GDP countries accounted for an average of only three per cent of natural gas consumption while low wealth-small GDP countries accounted for an average of eight per cent.

The electricity and heat generation and residential sectors are the largest sources of demand for natural gas in both the high wealth- and low wealth-large GDP countries (Figure 4). Specifically, these sectors account for a shared 63 per cent of natural gas demand in the low wealth-large GDP countries and 53 per cent of demand in the high wealth-large GDP countries. The high wealth-large GDP countries also have a large share of demand – 38 per cent – attributable to the industrial and commercial and public sectors. This is reflective of the fact that the high wealth-large GDP countries generally have greater levels of economic activity. Accordingly, these countries have greater demand for natural gas from business sectors.

FIGURE 4 NATURAL GAS CONSUMPTION BY SECTOR (2014)

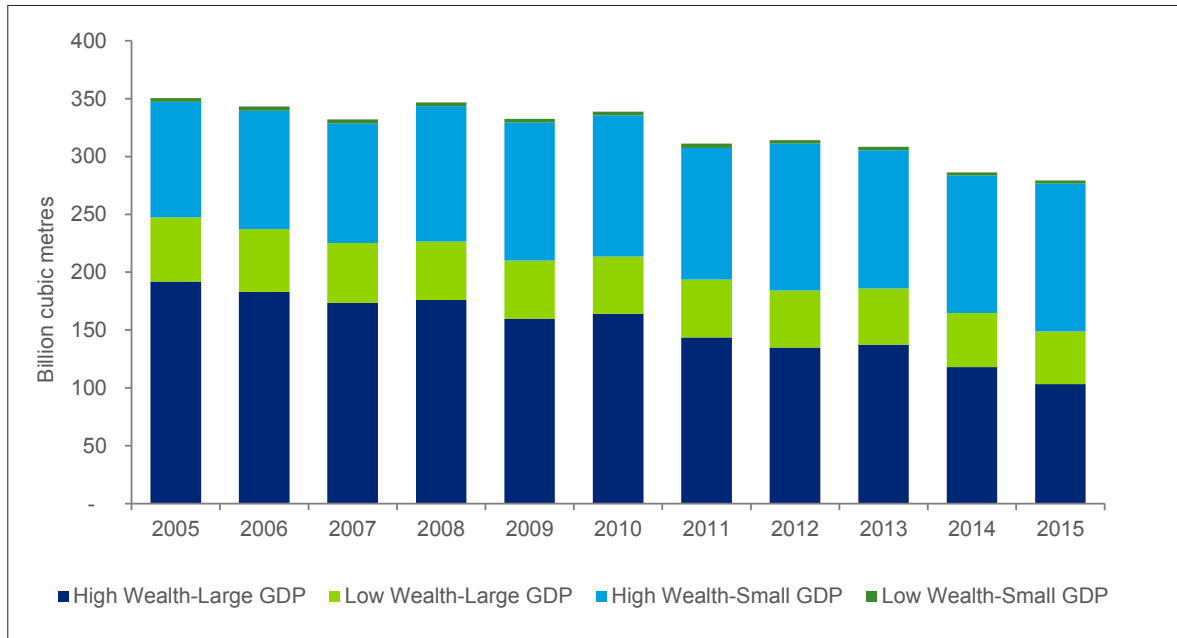


Source: International Energy Agency (2016c).

European Natural Gas Production and Reserves

Similar to consumption, natural gas production in Europe has been generally declining over the last decade, falling by 20 per cent from 2005 to 2015 (Figure 5). The largest share of Europe’s natural gas production – an average of 83 per cent from 2005 to 2015 – is from high wealth countries. This production is primarily attributable to three countries – the Netherlands, Norway and the United Kingdom. Of these three countries, Norway is the only one where natural gas production has increased over the last decade. Driven predominantly by Norway, the share of natural gas production attributable to high wealth-low GDP countries has increased from 28 per cent in 2005 to 46 per cent in 2015 while the share of production attributable to high wealth-high GDP countries has declined from 55 to 37 per cent.

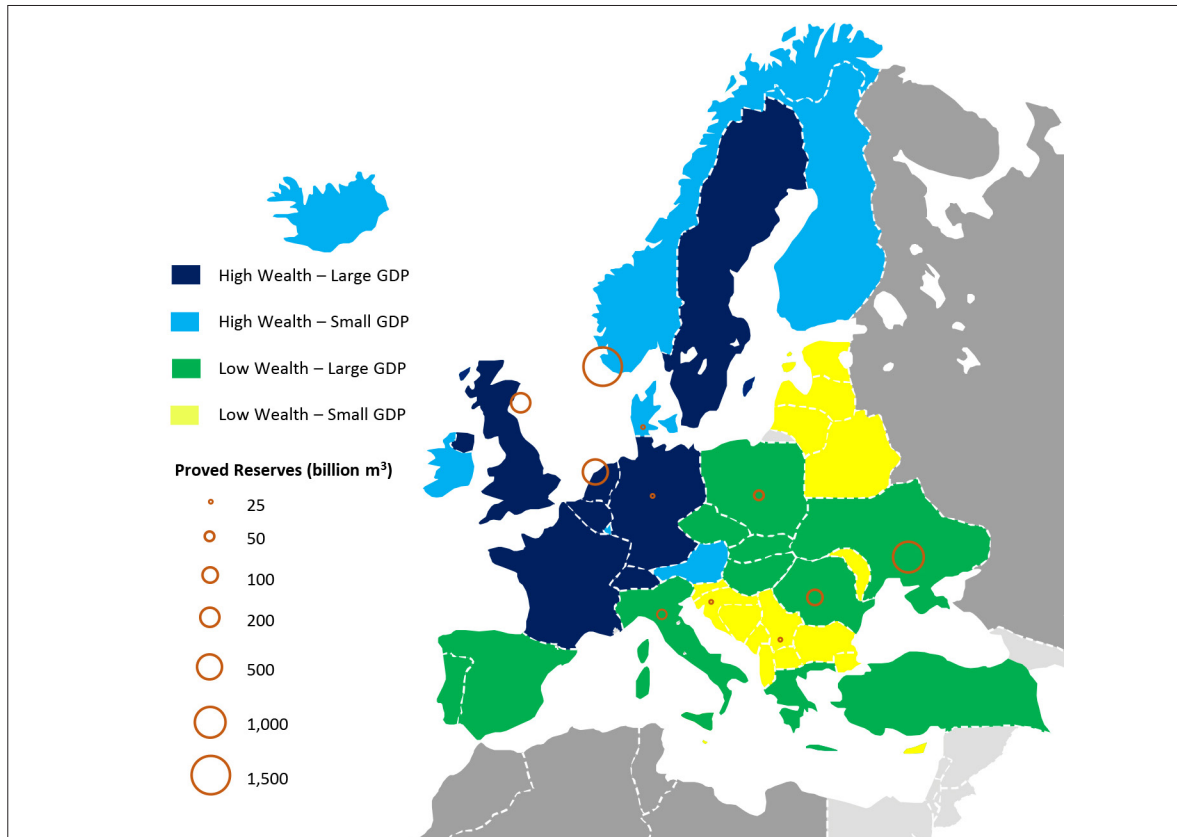
FIGURE 5 NATURAL GAS PRODUCTION IN EUROPE



Source: International Energy Agency (2016e).

The high share of production coming from the Netherlands, Norway and the United Kingdom reflects the fact that Europe’s natural gas reserves are largely concentrated in and near the North Sea (Figure 6). In 2016, proven reserves in Norway, the Netherlands and the United Kingdom totalled 2,900 billion cubic metres (BCM) and accounted for just under two-thirds of Europe’s total proven natural gas reserves. Europe’s largest continental reserves of natural gas are found in Ukraine. Proven reserves in Ukraine totalled 1,100 BCM in 2016, accounting for 25 per cent of Europe’s total proven reserves. Ukraine is also Europe’s largest continental producer of natural gas, accounting for seven per cent of total production in 2015. Europe’s remaining natural gas reserves are found primarily in Germany, Romania, Poland, Italy, Denmark, Serbia and Croatia.

FIGURE 6 PROVEN NATURAL GAS RESERVES WITHIN THE STUDY REGION (2016)



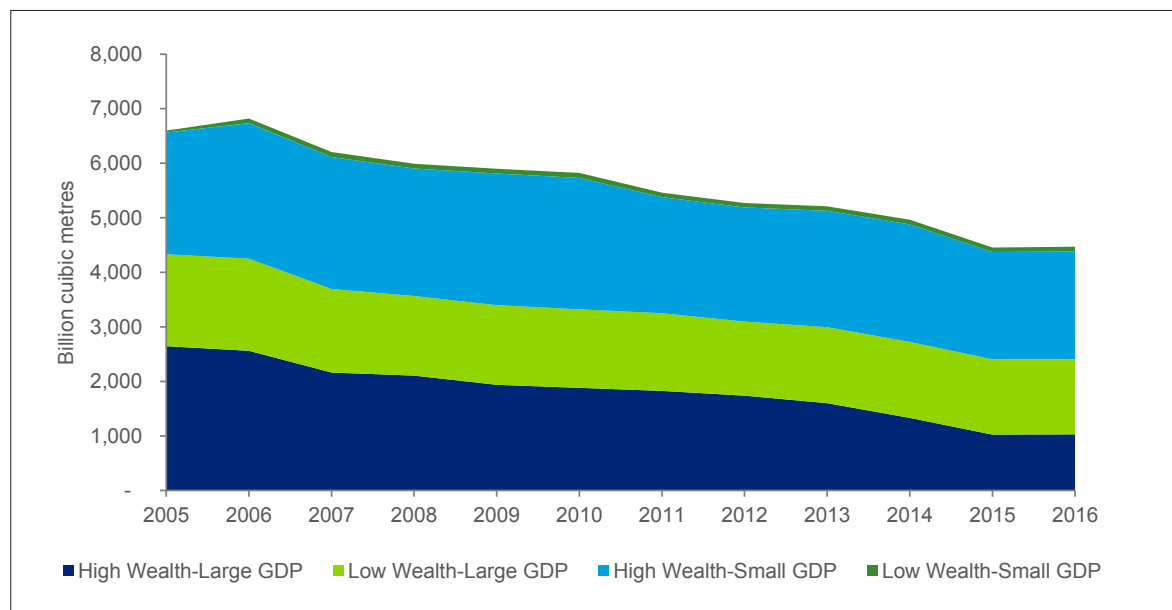
Source: U.S. Energy Information Administration (2017b).

Europe's natural gas production has been outpacing the identification of additional proven natural gas reserves over the last decade. As a result, Europe's total proven natural gas reserves are on the decline, falling by nearly 2,131 BCM (32 per cent) from 2005 to 2016 (Figure 7). Although Europe has substantial unproven reserves of wet shale gas, most recently estimated by the U.S. Energy Information Administration (EIA) in 2014 to be 16,900 BCM, any future production from these reserves is highly uncertain (U.S. EIA 2015c). First, given that the estimates of wet shale gas reserves remain unproven, achieving commercial production will require significant exploration and investment over an extended time period, and with no guarantee of a positive result. Poland, for example, has Europe's largest estimated shale gas reserves. Although it has seen significant exploration, the results have been disappointing. Only one-third of the wells drilled have produced gas via hydraulic fracturing, and the flows have only been 10 to 30 per cent of what is required to be profitable (Inman 2016). Similar disappointing results have led to international energy companies pulling out of exploration efforts in Denmark, Lithuania and Romania.

Also posing a significant challenge to future production from shale gas reserves is mounting public opposition to hydraulic fracturing. Opposition is driven primarily by the uncertainty related to its environmental and health impacts. A survey conducted by the European Commission in June 2015 indicated that respondents were split on whether shale gas brought new opportunities to their regions, and over a quarter of respondents felt that the European Union should consider banning hydraulic fracturing (European Union 2015). A large number of jurisdictions – including Austria, the Czech Republic, France, Germany, Bulgaria, the Netherlands, Scotland and Wales – have already taken this step by banning or placing moratoriums on hydraulic fracturing. This has rendered any shale gas resources in these countries at least temporarily unrecoverable (Patel and

Bakhsh 2015).⁴ England is now considered to be the most likely jurisdiction to establish a shale gas industry in Europe with at least three companies planning to hydraulically fracture test wells in 2018 (Vaughan 2017). Public opposition to the process is high, however, and support among England’s political parties is waning.⁵ The feasibility of hydraulic fracturing therefore remains highly uncertain.

FIGURE 7 PROVEN EUROPEAN NATURAL GAS RESERVES



Source: U.S. Energy Information Administration (2017b).

Note: Proved reserves of natural gas are the estimated quantities which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (U.S. EIA 2017a).

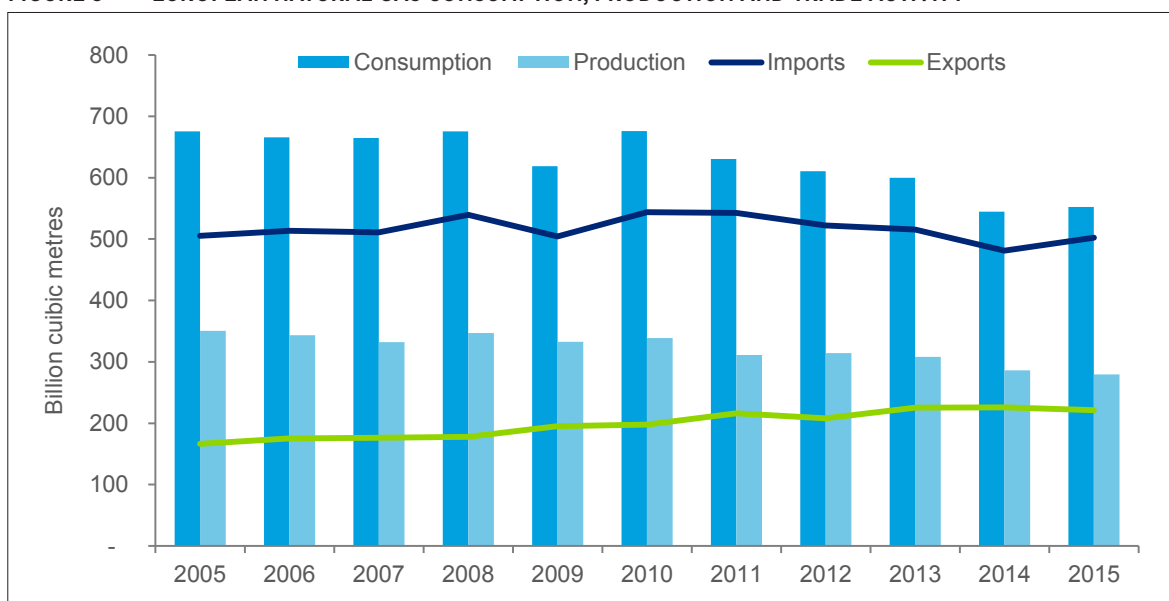
Natural Gas Trade in Europe

Europe has a significant net domestic natural gas imbalance (Figure 8). From 2005 to 2015, local consumption exceeded production by an average of 95 per cent (IEA 2016e). This corresponds to an average shortfall of 307 BCM per year that is met by imports from external suppliers. Europe’s net natural gas trade imbalance tracks closely with its net domestic natural gas shortfall, with imports of natural gas exceeding exports by an average of 318 BCM annually from 2005 to 2015. The absolute values of the domestic natural gas shortfall and trade imbalances declined from 2010 to 2014 as natural gas consumption declined. Both increased, however, in 2015 as consumption slightly picked up and production continued to decline. The combination of declining natural gas reserves, declining investment in natural gas production and natural gas consumption that has stabilized after a period of decline, means it is likely that the imbalances will start to increase again, and Europe will correspondingly have a greater demand for natural gas imports.

⁴ France, Germany, Bulgaria and the Netherlands account for 36 per cent of the unproven reserves in Europe estimated by the EIA. The EIA did not provide an estimate for reserves in Austria and the Czech Republic and reserves in the United Kingdom are primarily located in England (U.S. EIA 2015c).

⁵ In the 2017 general election the manifestos of the Labour Party, Liberal Democrats and Greens all committed to a ban on hydraulic fracturing. The Conservative Party, which formed a minority government, remains officially in support of the process. However, individual party members are increasingly calling it into question (Vaughan 2018).

FIGURE 8 EUROPEAN NATURAL GAS CONSUMPTION, PRODUCTION AND TRADE ACTIVITY



Source: International Energy Agency (2016e).

Note: Consumption in the study area exceeds indigenous production, hence imports are needed. IEA trade activity data may include volumes for re-trade but do not include volumes in transit.

Natural gas import activity in Europe tracked closely with consumption from 2005 to 2015. Europe’s natural gas import activity is split relatively evenly between high wealth-large GDP and low wealth-large GDP countries. High wealth-large GDP countries accounted for an average of 40 per cent of total imports in 2005 and their share grew to 50 per cent of total imports in 2015 (IEA 2016d). The share of imports consumed by low wealth-large GDP countries moved in the opposite direction, falling from 49 per cent in 2005 to 39 per cent in 2015. The differential change in shares is largely because of declining indigenous production in high wealth-large GDP countries over the time period. This resulted in a substantial increase in imports from 2005 to 2015. In contrast, production increased in low wealth-large GDP countries and imports correspondingly decreased.

Together, the large GDP countries consistently accounted for just under 90 per cent of annual European imports from 2005 to 2015. While their shares were similar over this period, the sources of imports were starkly different. Specifically, high wealth-large GDP countries source the majority of their imports – an average of 65 per cent from 2005 to 2015 – from other countries in Europe. In contrast, low wealth-large GDP countries are more highly dependent on natural gas imports from external sources. From 2005 to 2015, an average of 90 per cent of imports to low wealth-large GDP countries originated from outside of Europe. The exact sources of European imports will be discussed in greater detail at the end of this section.

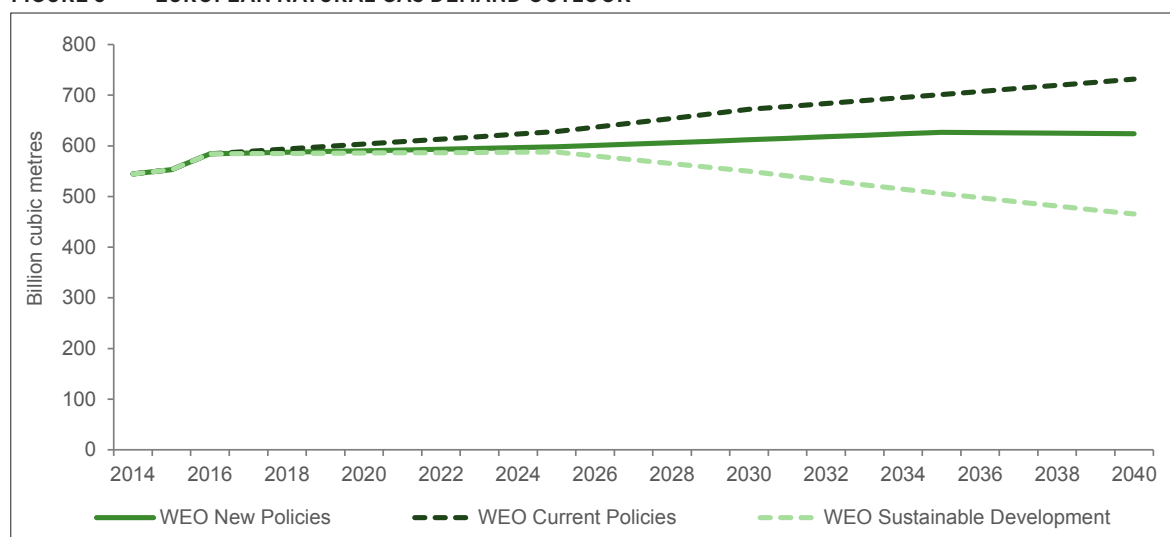
Natural Gas Outlook for Europe

The *World Energy Outlook (WEO) 2017* forecast from the IEA provides a natural gas forecast for Europe in three scenarios: “New Policies,” “Current Policies” and “Sustainable Development.” The “New Policies” scenario is effectively the WEO’s base case scenario and assumes countries introduce measures to implement all energy policy commitments and plans announced as of mid-2017. The “Current Policies” scenario assumes no change in energy policy from the mid-point of 2017 and the “Sustainable Development” scenario assumes countries adopt policies that will limit

carbon concentrations in the atmosphere while also limiting air pollution and improving energy access in developing countries.⁶

The “New Policies” scenario shows natural gas consumption in Europe slowly increasing through to 2035 and then declining slightly in 2040 (Figure 9). The rate of growth from 2014 to 2035 is expected to be slow, averaging only 0.5 per cent annually. By contrast, in the “Current Policies” scenario, consumption grows at a stronger rate of 1.1 per cent annually through to 2040. In the “Sustainable Development” scenario, natural gas consumption is forecast to grow only until 2020, and then decline at a rate of -1.1 per cent annually through to 2040.

FIGURE 9 EUROPEAN NATURAL GAS DEMAND OUTLOOK



Source: International Energy Agency (2016e, 2017).

Note: The three scenarios in the World Energy Outlook 2017 forecasts are “New Policies,” “Current Policies” and “Sustainable Development.” The “New Policies” is the WEO base case scenario and assumes that countries introduce measures to support and implement current energy policy commitments and plans. Forecasts for this scenario are provided for 2025, 2030, 2035 and 2040. The “Current Policies” Scenario assumes no changes in energy policy from the mid-point of 2017 and the “Sustainable Development” scenario assumes countries implement policies that achieve the joint goals of addressing climate change, limiting air pollution and improving energy access in developing countries. Forecasts for these scenarios are provided for 2025, 2030 and 2040.

These forecasts indicate that natural gas consumption will be largely influenced by Europe’s climate commitments. Interestingly, however, despite natural gas being put forward by its proponents as a bridging fuel that can help countries transition off of more carbon-intensive fossil fuels such as coal, natural gas consumption decreases in the WEO scenarios with stronger climate action. This is consistent with none of the countries in Europe having identified switching to natural gas-fired power from coal as a component of their climate change strategies.⁷

⁶ The “Sustainable Development” scenario replaces the “450” scenario which previously forecast energy production and consumption assuming that countries adopted climate policies that were sufficiently stringent to maintain carbon concentrations at levels below 450 ppm. As the 2017 World Energy Outlook also changed the geographical groupings used for the forecasts it is not possible to make a direct comparison between the “Sustainable Development” and “450” scenarios. However, in Europe, the “Sustainable Development” scenario seems to have resulted in a slight increase in forecast natural gas demand.

⁷ Based on a review of Nationally Determined Contributions (NDC) submitted to the United Nations Framework Convention on Climate Change. Countries in the European Union submitted a single NDC on behalf of all member states. Albania, Belarus, Iceland, Norway and Ukraine submitted individual NDCs. As of July 2017, the following countries have not submitted an NDC: Macedonia, Montenegro, Serbia, Switzerland and Turkey (United Nations Framework Convention on Climate Change 2017).

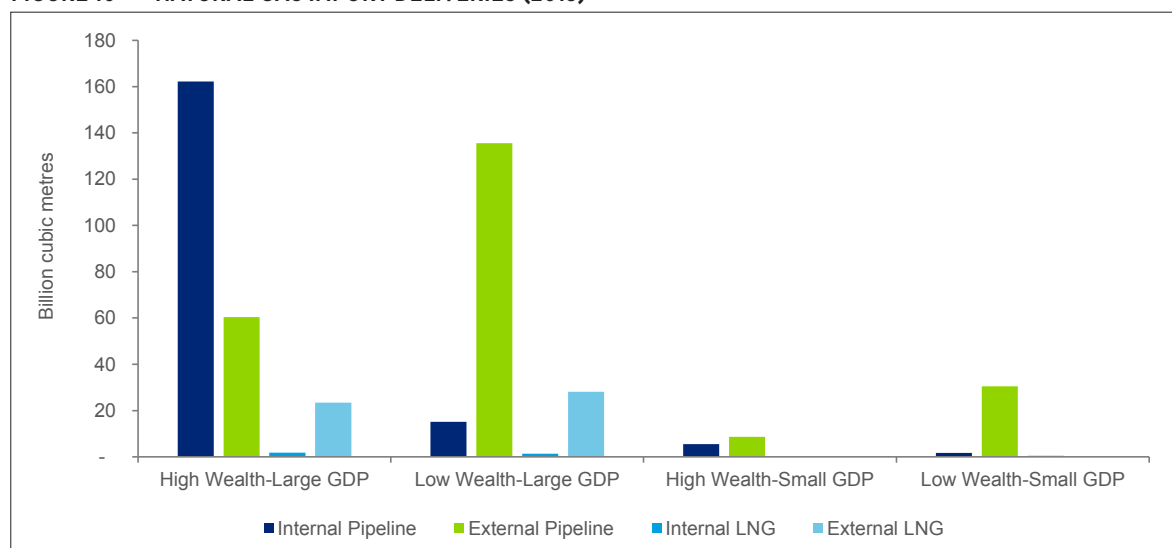
Lower natural gas consumption in the “New Policies” and “Sustainable Development” scenarios are driven by a combination of lower energy demand, higher use of renewables and nuclear power, and higher use of bioenergy.⁸ It also points toward an inverted-U relationship between climate commitments and natural gas consumption. In particular, preliminary climate commitments may encourage greater natural gas use as countries switch toward lower emitting carbon sources of energy. However, as climate commitments strengthen this will necessitate a decline in natural gas use as countries turn toward zero emission sources of energy instead.

In addition to climate commitments, economic activity will also continue to be a determinant of growth in natural gas demand. In particular, the economies of high wealth countries tend to be more mature and are therefore expected to experience lower growth. Low wealth countries, in contrast, will generally experience higher growth rates as their economies continue to develop. However, natural gas production is decreasing faster in high wealth countries than in low wealth countries. Moreover, low wealth countries are also more dependent on Russia as a supplier, which can be expected to aggressively maintain its market share (Elliott and Reale 2017). As discussed in more detail below, these two factors indicate that high wealth countries are a potentially better target market for Canadian exports.

Natural Gas Infrastructure in Europe

Pipelines are the predominant means of delivering natural gas imports to Europe. In both high wealth- and low wealth-small GDP countries, pipelines account for virtually 100 per cent of imports (Figure 10). In both groups of countries imports are sourced primarily from outside of Europe although high wealth countries have a non-negligible share (39 per cent of imports of known origin) that are sourced from countries within Europe.

FIGURE 10 NATURAL GAS IMPORT DELIVERIES (2015)



Source: International Energy Agency (2016d).

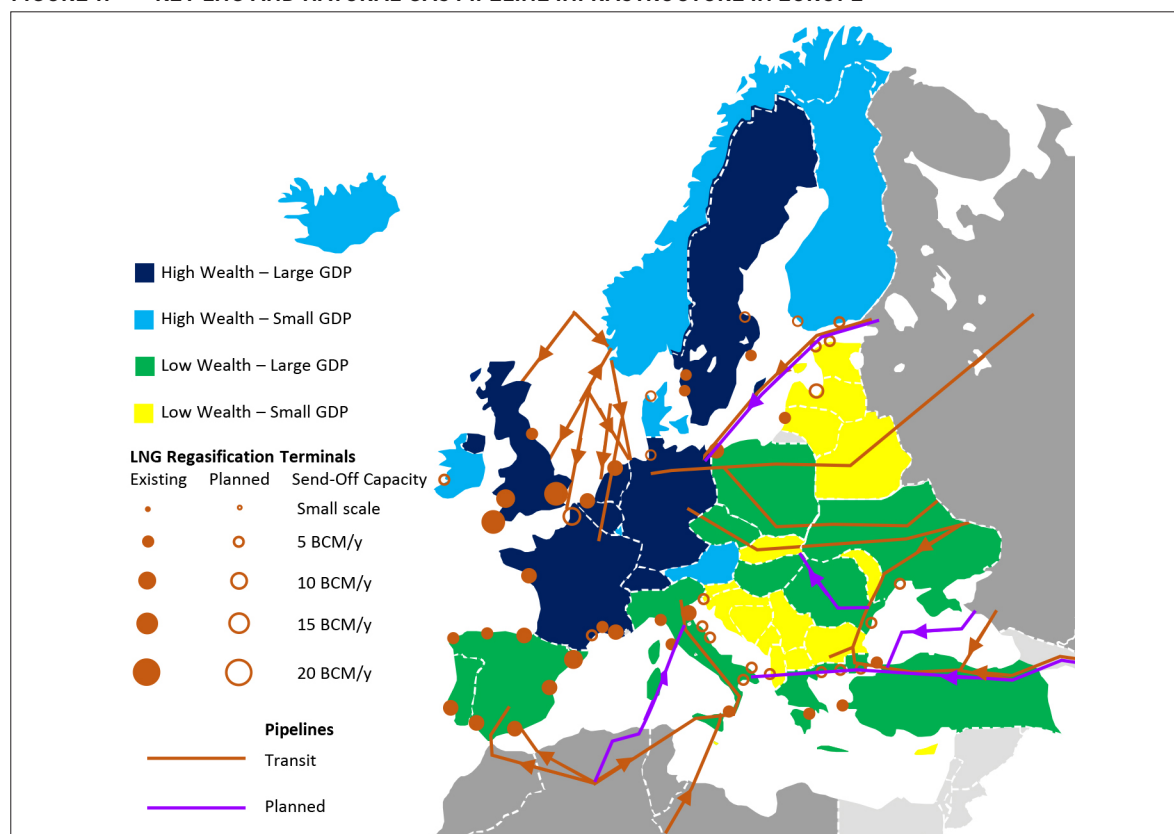
Note: “Internal Pipeline” and “Internal LNG” refer to imports that originate from a country within Europe. “External Pipeline” and “External LNG” refer to imports that originate from a country outside of Europe. Imports of unknown origin are not shown.

⁸ While decreased energy demand and an increase in renewables and bioenergy is likely to occur across all countries in Europe, changes in the shares of nuclear energy will be country specific. This reflects differing public and political comfort with nuclear power across Europe. For example, in the wake of the Fukushima accident in Japan in 2011, Germany and Belgium both announced plans to phase out nuclear power and France has chosen to cap its nuclear generating capacity and decrease its share of the electricity generation mix from 75 to 50 per cent. In contrast, the United Kingdom is constructing a new nuclear power plant and the Netherlands is open to new investment in nuclear energy (Deloitte 2015).

In high wealth- and low wealth-large GDP countries, pipelines account for 90 and 85 per cent of total imports respectively (IEA 2016d). Although these total shares are similar, as noted previously, the source of imports varies drastically between high wealth and low wealth countries. Specifically, in 2015 high wealth-large GDP countries received 73 per cent of their pipeline imports (of known origin) from internal supply sources. In contrast, external pipeline imports were the overwhelmingly dominant source of imports for low wealth-large GDP countries, accounting for 90 per cent of pipeline imports.

Europe is currently supplied by major natural gas transit pipelines from the North Sea, Russia, the Middle East and North Africa (Figure 11).⁹ Further connectivity and robustness are provided by transmission pipelines that move natural gas from the transit pipeline hubs to areas of demand.¹⁰ Together, the transit and transmission pipelines provide comprehensive natural gas supply coverage throughout the continent.

FIGURE 11 KEY LNG AND NATURAL GAS PIPELINE INFRASTRUCTURE IN EUROPE



Source: European Network of Transmission System Operators for Gas (2016) and International Group of Liquefied Natural Gas Importers (2015).

Note: The above figure includes a selection of pipelines that transport natural gas produced from wells in the North Sea, as well as all major pipelines that transport natural gas into Europe from external suppliers (transit pipelines). In addition to the pipelines indicated on this map there is an extensive transmission pipeline network that transports natural gas from major pipeline hubs to areas of demand. A full representation of Europe's natural gas pipeline network is available from the European Network of Transmission System Operators for Natural Gas.

⁹ Specific details of the pipeline systems are discussed in Appendix B.

¹⁰ Generally speaking, transit pipelines are those that cross multiple countries or regions and are not necessarily connected to a domestic transmission system. For a discussion of the difference between transit and transmission pipelines in Europe, see Energy Charter Secretariat (2012) and Leal-Arcas (2015).

The North Sea has an extensive natural gas pipeline network that connects its gas fields with the primary producing countries of Norway, the United Kingdom and the Netherlands. A number of additional high wealth-large GDP countries in Western Europe – including Belgium, Denmark and Germany – also have pipeline connections to either offshore natural gas production sites or major natural gas receipt points in Norway and the United Kingdom. These pipelines are the primary conduit for internal natural gas trade among high wealth-large GDP countries.

Two pipelines transport natural gas from Russia to Europe through Ukraine, and three more bypass Ukraine. Gazprom, Russia's largest natural gas company, partially or fully owns all five pipelines. From North Africa, three pipelines connect to southern Europe, and from the Middle East, two pipelines connect to Turkey. There are also five major pipelines under development, connecting Europe to supply from Algeria, Azerbaijan and Russia.

In addition to pipeline imports, large GDP countries also obtain a small share of imports through LNG. The vast majority of LNG imports originate outside of Europe. Although LNG imports can be delivered from any country, regardless of geographic proximity to Europe, they are currently sourced primarily from the Middle East and Africa; the largest suppliers are Algeria, Nigeria and Qatar. The only LNG suppliers to Europe from the Americas in 2015 were Trinidad and Tobago and Peru, though the United States supplied Europe in 2017 (Elliot and Reale 2017; IEA 2017).

Europe currently has 26 operating large-scale LNG regasification terminals, each with a minimum send-off capacity of 0.5 BCM per year (Table 2). These terminals are located in 12 countries, primarily large GDP-high wealth countries (four countries, nine terminals) and large GDP-low wealth countries (six countries, 14 terminals). There are only two terminals located in small GDP-low wealth countries (Lithuania and Malta) and no terminals in small GDP-high wealth countries. An additional large-scale facility in Spain has been completed but is in hibernation until demand picks up. Last, there are six more small-scale LNG terminals located in Germany, Finland, Norway and Sweden. These terminals have individual send-off capacities of less than 0.5 BCM per year. Combined, Europe's total LNG regasification capacity at the end of 2017 was 220 BCM (Gas Infrastructure Europe 2017).

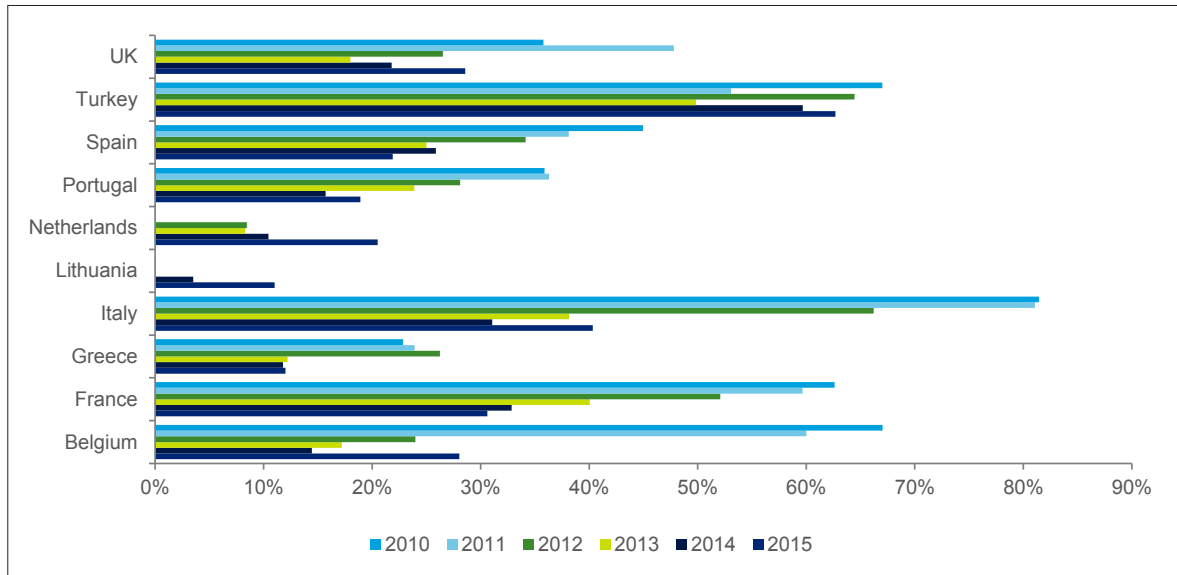
TABLE 2 LARGE-SCALE OPERATING LNG REGASIFICATION TERMINALS IN EUROPE (2017)

Existing Facility	Country	Current Capacity (BCM/yr)	Planned Expansion	Additional Capacity	In-Service Year
Zeebrugge	Belgium	9.00	No	-	-
Fos-Tonkin	France	3.00	No	-	-
Montoir-de-Bretagne	France	10.00	Yes	2.50	2020
Fos Cavaou	France	8.25	Yes	2.75	2020
				5.50	2022
Dunkerque	France	13.00	No	-	-
Revithoussa	Greece	5.00	Yes	2.00	2018
Panigaglia	Italy	3.40	No	-	-
Porto Levante	Italy	7.58	No	-	-
FSRU OLT Offshore LNG Toscana	Italy	3.75	No	-	-
FSRU Independence	Lithuania	4.00	No	-	-
Malta Delimara	Malta	0.7	No	-	-
Gate terminal, Rotterdam	Netherlands	12.00	Yes	4.00	N/A
Świnoujście	Poland	5.00	Yes	2.50	2020
Sines	Portugal	7.60	No	-	-
Barcelona	Spain	17.10	No	-	-
Huelva	Spain	11.80	No	-	-
Cartagena	Spain	11.80	No	-	-
Bilbao	Spain	8.80	No	-	-
Sagunto	Spain	8.80	No	-	-
Mugardos	Spain	3.60	Yes	3.60	2023
Marmara Ereğlisi	Turkey	6.20	No	3.70	N/A
Aliaga Izmir	Turkey	6.00	No	2.80	N/A
Aliaga Etki	Turkey	5.00	No	-	-
Isle of Grain	United Kingdom	19.50	Yes	8.00	N/A
Milford Haven - Dragon	United Kingdom	7.60	No	-	-
Milford Haven - South Hook	United Kingdom	21.00	No	-	-
TOTAL		219.48		37.35	

Source: Adapted from Gas Infrastructure Europe (2017, 2018).

Europe's LNG regasification and send-off capacity far exceeds its level of LNG imports. In 2015, capacity was 197 BCM whereas imports were only 55 BCM, a utilization rate of only 28 per cent. Generally speaking, the differential between capacity and imports mostly increased in recent years as European LNG imports declined (Figure 12). Despite these falling utilization rates an additional 20 large-scale LNG regasification terminals are planned for Europe (Table 3). In addition to these large-scale facilities, nine of the 26 operating LNG regasification facilities have planned expansions in capacity and there are six small-scale LNG regasification facilities either planned or under construction. If all of these plans were to move ahead, then with the combination of existing capacity, planned expansions and new construction Europe would reach 365 BCM of regasification capacity.

FIGURE 12 CAPACITY UTILIZATION OF EUROPEAN LNG REGASIFICATION FACILITIES



Source: Gas Infrastructure Europe (2018) and International Energy Agency (2016d).

Note: Poland and Malta are excluded from the above figure as their LNG regasification facilities only started operating in 2016 and 2017 respectively.

The further development of Europe's LNG import capacity is driven largely by concerns that, although Europe's natural gas import and transportation infrastructure is well developed for current needs, it is not necessarily well prepared for future uncertainties. These uncertainties include a significant domestic natural gas imbalance that looks set to widen again, given current forecasts for consumption and production of natural gas, as well as geopolitical instability among many of Europe's largest external natural gas suppliers. In particular, in Eastern Europe there is a political desire to achieve energy independence from Russia, which currently supplies the majority of natural gas for the region. This in part motivated the opening of Lithuania's first LNG import facility in 2014 and Poland's first facility in 2016. Five more Eastern European countries are advancing plans to open their first import facility. The further development of these and other regasification terminals throughout Europe is being viewed as an important component of ensuring the security of Europe's future energy supply and is being advanced and supported by the European Commission (European Commission 2016).

There is also concern, however, that Europe's future energy supply cannot be secured by the further development of LNG import capacity alone. In particular, Europe's natural gas pipeline network is not designed to widely distribute natural gas that is received as LNG at coastal import hubs. For example, Spain accounts for nearly a third of Europe's current LNG import capacity and five per cent of planned capacity (Gas Infrastructure Europe 2018). While current LNG import facilities in Spain operate well below capacity, pipeline connections from Spain to France are limited and primarily carry natural gas in the opposite direction.¹¹ Without additional pipeline capacity, Spanish LNG terminals are therefore limited in their use as an import point for natural gas supply for other countries in Europe. A similar scenario exists in France with a lack of pipeline capacity to move regasified LNG either east to Germany or south to Italy.

¹¹ There are currently only two natural gas pipelines connecting France and Spain. The Biriadou has a capacity of approximately 0.25 BCM per year. It has historically carried gas from Spain to France but has not moved any substantive quantities since 2011. The Larrau has a capacity of approximately 7.2 BCM per year. It is currently in operation but only carries natural gas from France to Spain (IEA 2016d).

TABLE 3 LARGE-SCALE PLANNED LNG REGASIFICATION TERMINALS IN EUROPE (2017)

Proposed New Facility	Country	Capacity (BCM/yr)	Status	In-Service Year
Eagle (Levan)	Albania	4.0 - 8.0	Planned	N/A
Krk Island LNG	Croatia	2.6	Planned	N/A
		6.0	Planned	By 2022
Muuga (Tallinn)	Estonia	2.0	Planned	2018
Paldiski	Estonia	2.5	Planned	2020
Brunsbüttel	Germany	3.0 - 4.0	Planned	N/A
Alexandroupolis	Greece	6.0	Planned	2020
Cork	Ireland	N/A	Planned	N/A
Shannon	Ireland	2.7 - 9.0	Planned	Three phases
Porto Empedocle (Sicilia)	Italy	8.0	Planned	2022
Skulte	Latvia	5.0	Planned	2019
Malta	Malta	2.0	Planned	2026
FSRU Polish Baltic Sea Coast	Poland	4.0 - 8.2	Planned	2023
Gijón (El Musel)	Spain	7.0	Constructed, Non-Operational	N/A
Tenerife (Arico-Granadilla)	Spain	1.3	Under construction	2021
		0.7	Planned	N/A
Gran Canaria (Arinaga)	Spain	1.3	Under construction	2022
		0.7	Planned	N/A
FSRU Iskenderun	Turkey	7.3	Planned	2019
FSRU Gulf of Saros	Turkey	7.3	Planned	2019
First Gas (Yuzhny)	Ukraine	5.0	Planned	N/A
		5.0		
Port Meridian	United Kingdom	5.0	Planned	2019
Trafigura Teesside	United Kingdom	4.2	Planned	2018
MAXIMUM TOTAL		108.1		

Source: Adapted from Gas Infrastructure Europe (2017, 2018).

Notes: The Gijon El Musel regasification terminal in Spain was completed in 2014 but is in hibernation until demand picks up (Gas Infrastructure Europe 2017).

Existing pipeline restrictions – and the limited or zero access of some countries to LNG supply as a result – are partially why the European Commission is promoting the development of LNG import facilities in a wide range of countries. For the strategy to be successful in securing energy supply across the entire continent, however, further development of Europe’s pipeline network is still required. In particular, the countries that are most vulnerable to supply disruptions are those that rely primarily on imports from outside of Europe. These are largely the low wealth countries – both large and small GDP – that are located mainly in Central and Eastern Europe. Nearly all of the natural gas in this region currently flows by pipeline from east to west and then from Central Europe out toward the north and south coasts (Snow 2015). For LNG to aid in providing energy security in these countries, either current pipelines need to be reversed or additional pipeline capacity that moves natural gas in the opposite directions needs to be added.

Considerations for Europe’s Natural Gas Supply

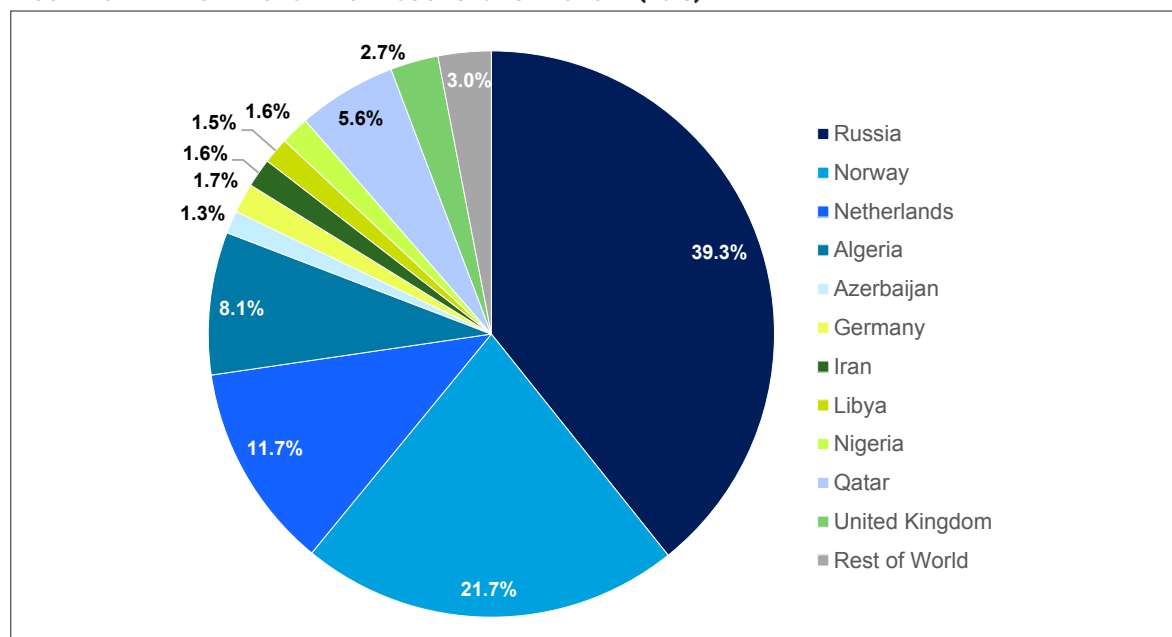
Natural gas supply to Europe is heavily dependent on a few predominate sources, both internal and external. Only four supply sources – Russia, Norway, the Netherlands and Algeria – provided over

80 per cent of Europe’s natural gas imports from known sources in 2014 (Figure 13).¹² Russia was by far the largest source, accounting for nearly 40 per cent of imports, followed by Norway (22 per cent), the Netherlands (12 per cent) and Algeria (eight per cent).

The high wealth-large GDP countries are the most diversified in terms of large natural gas suppliers. As noted earlier, this is primarily because a majority share of imports – 66 per cent in 2015 – are sourced from other countries in Europe (IEA 2016d). Norway is the largest supplier to the region, accounting for 39 per cent of imports in 2015, and then the Netherlands which accounted for 20 per cent (Figure 14). Looking outside of Europe, Russia is the largest external supplier to these countries, providing 23 per cent of imports in 2014. Further diversification of external suppliers is supported by LNG import capacity that allows countries to access natural gas supplied by the Middle East and Africa.

Russia dominates natural gas imports to low wealth-large GDP countries, supplying just shy of 50 per cent of imports to these countries in 2015 (IEA 2016d). With both LNG import capacity and pipeline connections to North Africa and the Middle East, however, low wealth-large GDP countries are the most diversified with respect to secondary supply sources of natural gas. Through a mix of both pipelines and LNG, Algeria accounted for 19 per cent of imports to these countries in 2015. Eight more countries in Europe, Africa and the Middle East had import shares that ranged between two and five per cent.

FIGURE 13 NATURAL GAS IMPORT SOURCES FOR EUROPE (2015)



Source: International Energy Agency (2016d).

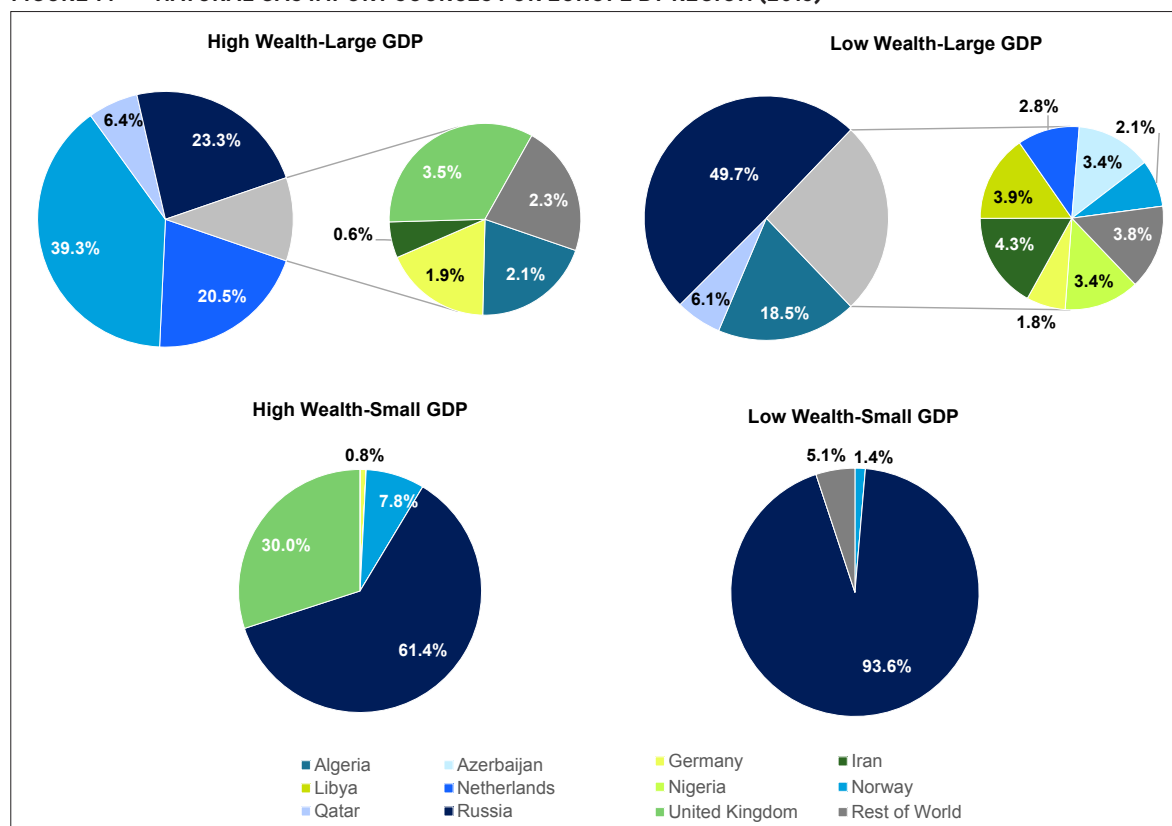
Note: Percentages are calculated as a share of imports of known origin. Imports of unknown origin are equal to approximately seven per cent of total imports.

¹² All of the reported import shares in this section are based on total imports of specified origin. Imports for which the origin is unspecified or not known have been excluded. Imports of unspecified or unknown origin accounted for just under six per cent of total imports to Europe in 2015 but are concentrated in only a small number of countries, most notably Austria (50 per cent of total imports), Ukraine (62 per cent), Germany (two per cent), France (six per cent) and Italy (nine per cent). As the International Energy Agency’s database of natural gas by origin includes 81 originating countries, we suspect a significant share of these unknown imports comes from originating countries that are included in the database. We therefore opt to exclude these imports from the calculation of import shares as including them as “Rest of the World” would likely overestimate the size of this share.

Relative to their large GDP counterparts, the small GDP countries have notably less diversity with respect to sources of import supply. In particular, largely due to their geography, both groups of countries are significantly more reliant on imports from Russia. Specifically, among the high wealth-small GDP countries, the largest importers of natural gas are Austria and Luxembourg (landlocked in Central Europe), Finland (Russia’s northern neighbour), Denmark and Ireland. In 2015, these countries obtained 61 per cent of their imports from Russia, 31 per cent from the United Kingdom and eight per cent from Norway. Among small GDP-low wealth countries, the large majority – all but Malta and Cyprus – are located in Central and Eastern Europe, an area that is served almost exclusively by pipeline natural gas from Russia. While a number of these countries have coastal access, Lithuania is the only country that currently has an LNG import facility. Accordingly, low wealth-small GDP countries source virtually all of their imports – 94 per cent in 2015 – from Russia.

In looking at natural gas import sources by origin, it is evident that low wealth countries in Europe are relatively less energy secure and more dependent on potentially unstable sources of natural gas. In particular, low wealth-small GDP countries are virtually exclusively dependent on Russia for natural gas supplies. These countries are likely to be the most interested in diversifying away from Russian natural gas, but without additional LNG and pipeline infrastructure they are also the least capable of making any major changes to their supply.

FIGURE 14 NATURAL GAS IMPORT SOURCES FOR EUROPE BY REGION (2015)



Source: International Energy Agency (2016d).

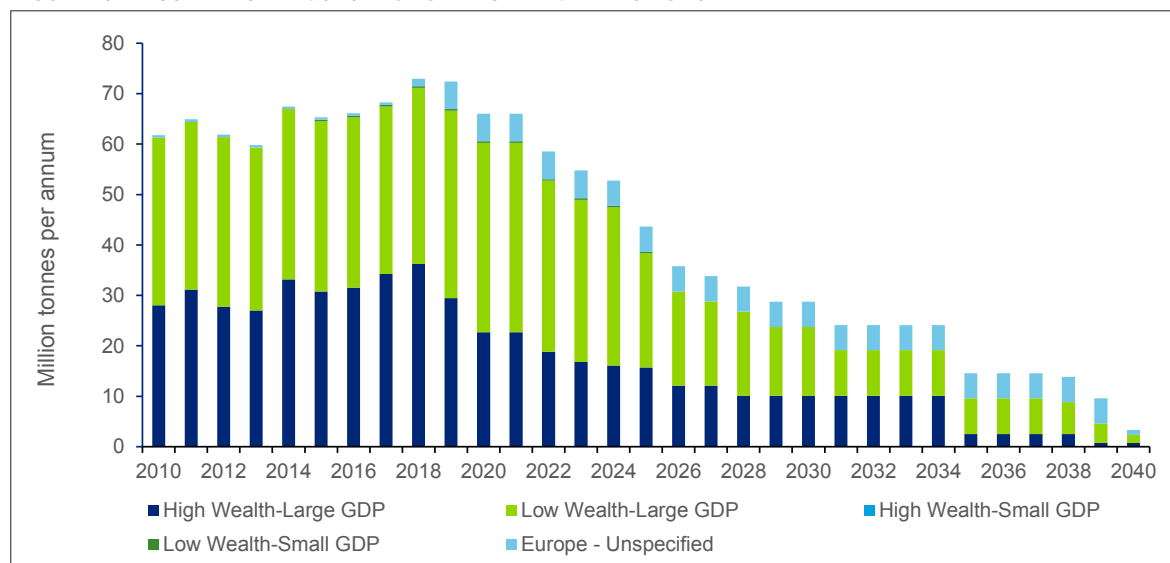
Note: “Rest of the World” only includes imports of known origin.

Although low wealth-large GDP countries have a higher diversity of supply sources, 90 per cent of supplies are coming from countries outside of Europe, many of which have geopolitical instabilities that could disrupt their natural gas exports. They therefore have a similar motivation to identify more stable sources of natural gas supply. The extent to which countries will be successful again depends on their available infrastructure.

For eastern European countries without LNG import capacity – Ukraine, Hungary and Romania, for example – achieving this diversity will be more challenging. For countries with LNG capacity, more options for supply diversification are available, although they may be limited in the short term by current contracts. Current contracted LNG volumes for delivery in low wealth-large GDP countries in Europe increase through to 2020 (Figure 15). They then start a gradual but steady decline in 2022, falling to less than half of currently contracted volumes by 2027. Excess regasification capacity means that importing low wealth-large GDP countries have the infrastructure to receive additional LNG supplies in excess of current contracted quantities. However, in the short term, the need for this supply will be dependent on whether forecast demand growth is realized. If not – or if demand growth is limited – then the greatest opportunity for market entry by new suppliers is to secure contracts for deliveries that start in the next five to 10 years.

In contrast, a nearer term opportunity for market entry exists in the high wealth-large GDP countries where current contracted volumes drop off starting in 2019. A nearer term opportunity may also exist in the low wealth countries that have recently added regasification infrastructure (Lithuania and Poland) or, as previously noted, which are considering the addition of LNG infrastructure (Albania, Croatia, Estonia, Latvia, Malta, Romania and Ukraine), as contracted volumes for deliveries to these countries are either non-existent or limited.

FIGURE 15 CONTRACTED VOLUMES FOR LNG DELIVERY TO EUROPE



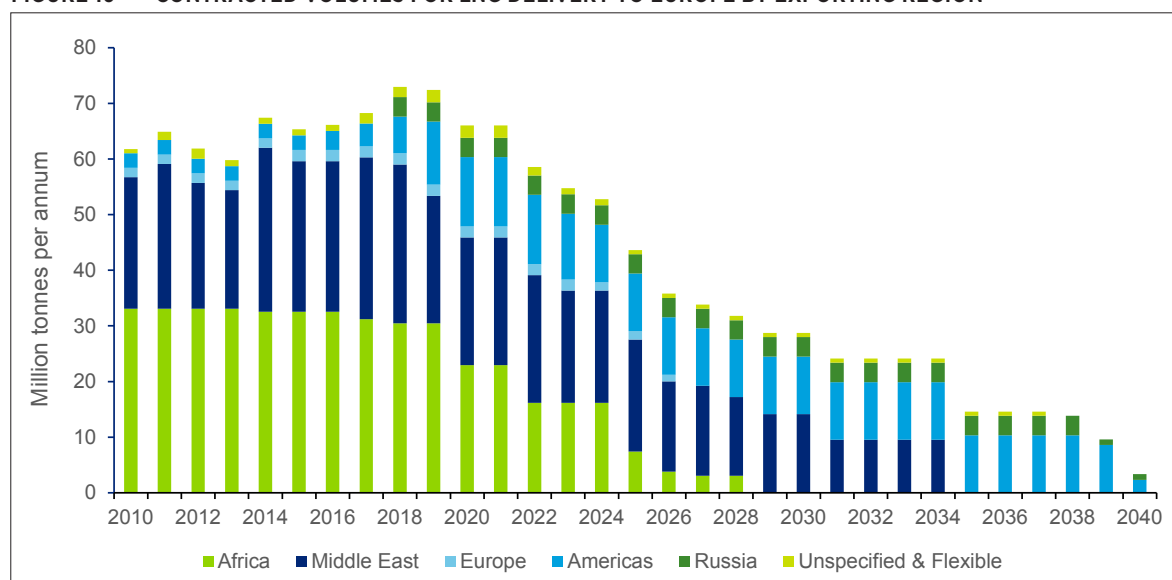
Source: Bloomberg (2017b).

Note: The category “Europe - Unspecified” is contracted volumes bought by Engie (a French natural gas supplier) with unspecified import country. Between 2010 and 2040, a maximum of 49 MTPA and a minimum of two MTPA of contracted volumes go to unspecified importers worldwide. These volumes are not included in the figure. As a number of these importers are likely to be in Europe, this means the data presented likely underestimate the total contracted volumes going to Europe. However, the trend with these unspecified contracts is the same as specified contracts: peaking in 2018 to 2021 and declining thereafter.

In looking at the source of contracted LNG deliveries to Europe over the last six years, Africa has consistently been the largest supplier, followed closely by the Middle East (Figure 16). Looking ahead, contracts for supply from Africa drop off sharply starting in 2020, and there are no contracts in place for delivery from Africa in 2029 and beyond. Current contracted volumes for deliveries from the Middle East are more constant. They follow a more gradual decline than those from Africa and do not drop to zero until 2035. In contrast, although a much smaller supplier, contracted LNG deliveries from the Americas to Europe increase from 2016 to 2020, and the U.S. is one of only two countries (the other being Russia) with contracted deliveries extending all the way to 2040. This reflects the impact of contracts that have been recently signed by new

liquefaction facilities in the U.S. and is strongly indicative of Europe’s interest in diversification of supply sources in the long term.

FIGURE 16 CONTRACTED VOLUMES FOR LNG DELIVERY TO EUROPE BY EXPORTING REGION



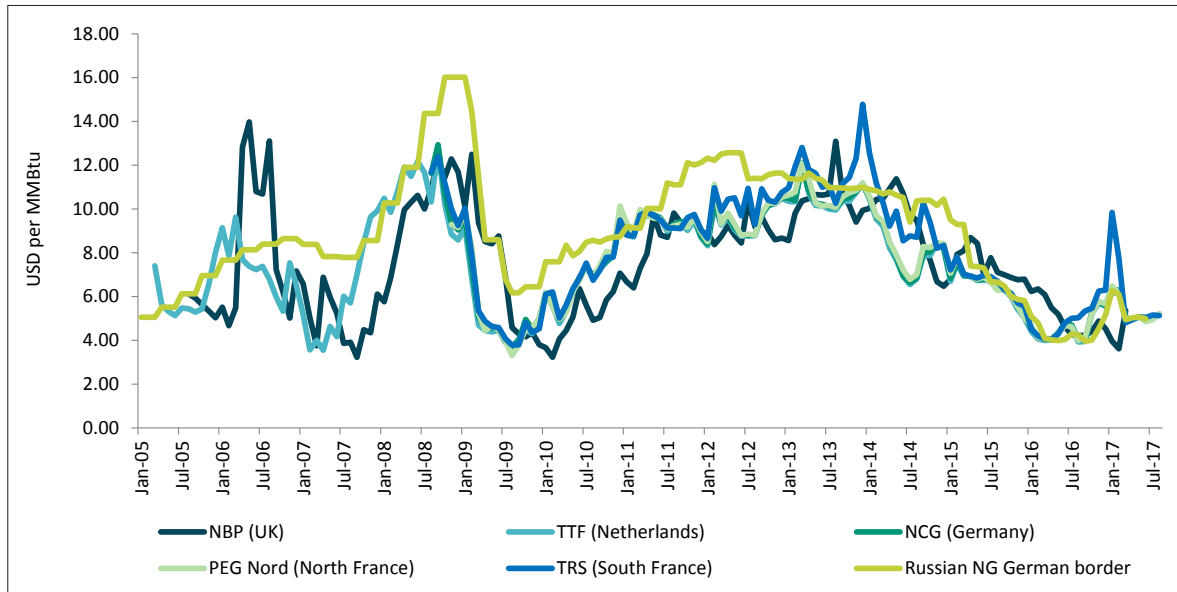
Source: Bloomberg (2017b).

Prices will play an important role going forward for determining the attractiveness of Europe to alternative supply sources. Furthermore, evolving pricing and contracting conventions in the global natural gas market environment may influence supply choices for European countries. While long-term natural gas contracts supplying Europe with Russian natural gas are still typically linked to oil prices, they have started to align with European natural gas hub prices (Stern and Rogers 2013, 2014; Henderson and Mitrova 2015). Also, some more recent agreements are based on spot market rates (CIEP 2014; Stratfor 2014; Vukmanovic and Jewkes 2014).

Prices at the European hubs generally track each other, with occasional disconnections observed in the U.K.'s National Balancing Point (NBP) and South France's Trading Region South (TRS) hub prices (Figure 17). The Russian price at the German border has historically been higher, but in 2016 and 2017 tracks more closely with the continental European hubs. The move toward spot pricing in European natural gas markets will potentially place oil-linked LNG at a competitive disadvantage, even with continued low oil prices.¹³ Moreover, the proximity of Russia, and its lower cost supplies of gas, also undermines the attractiveness of more expensive LNG and the investment required for expansion of regasification facilities (Stratfor 2014).

¹³ For example, an oil-linked LNG contract that prices LNG at 15 per cent of the price of oil (a fairly standard linkage; see Moore et al., (2014)) has a price of \$6/MMBtu at \$40 per barrel.

FIGURE 17 MONTHLY NATURAL GAS PRICES FOR SELECTED EUROPEAN HUBS



Source: (1) Bloomberg (2017a). Historical natural gas spot prices for NBP (NBPGWTHN Index), TTF (TTFGDAHD Index), Zeebrugge (ZEEBWTHN Index), NCG (EGTHDAHD Index), PEG Nord (PNXIGNWD Index). (2) International Monetary Fund (2017a, 2017b), Russian natural gas border price in Germany (PNGASEU).

Note: Availability of price data varies across the different price series. Specifically, data for Russian natural gas are available from January 2005 to summer 2017. Data for NBP (UK) and TTF (Netherlands) are available from March 2005 to spring 2017. Last, data for NCG (Germany) and TRS (South France) are available from August 2008 to spring and summer 2017 respectively while data for PEG Nord (North France) are available from November 2008 to summer 2017.

Among Europe’s current suppliers, Russia remains the best positioned to continue to serve as a primary source of imports with estimated reserves of nearly 48,000 BCM in 2016 (U.S. EIA 2017b). This is nearly 10 times the size of estimated reserves in Europe. In addition, while Europe’s reserves have been steadily declining over the last decade, reserves in Russia have remained virtually constant, despite average production levels of over 640 BCM per year (IEA 2016e).

Iran also has substantial natural gas reserves and is the only current European supplier that has seen a large increase in reserves over the last decade. Specifically, reserves have risen from just over 26,000 BCM in 2005 to 34,000 BCM in 2016. Following the recent period of economic sanctions, however, Iran will require significant investment in its natural gas industry to reach a production level that exceeds growing domestic demand and current export contracts. Export infrastructure to Europe is also currently limited to the Tabriz-Ankara pipeline, and Turkey is correspondingly the only European importer of Iranian natural gas. Assuming investment levels that lead to a sufficient increase in natural gas production, Iranian exports to Europe via Turkey could increase to 10 to 20 BCM annually in the 2020s (Dickel et al. 2014). More significant exports beyond 2030 are possible but will require investment in new pipeline or LNG export infrastructure.

Natural gas reserves in Qatar are approximately a third lower than in Iran – 25,000 BCM – and have been declining slowly over the last decade. With the world’s largest LNG export capacity, Qatar has access to global natural gas markets. In particular, markets in Asia have higher natural gas prices, faster growing demand and are generally within a similar distance to Qatar as Europe. As a result, a continued focus on Asian exports –which accounted for 55 per cent of Qatari exports in 2015 (IEA 2016d) – is likely to be a preferred strategy for Qatar. In summer 2017, Qatar announced plans to increase natural gas production and LNG exports between 2022 and 2024 (DiChristopher 2017); however, its ability to increase exports to Europe in the near term remains limited to marginal amounts of output that have not been committed via current supply contracts.

Europe's remaining key external suppliers – Algeria, Azerbaijan, Libya and Nigeria – have reserves ranging from approximately 1,000 to 5,000 BCM. In addition, a recent offshore natural gas reserve discovery in Egypt – previously a supplier to Europe in the late 2000s – has reserves approximately equal to the Netherlands. Production could start as early as 2018 and while the priority for output will be servicing Egyptian demand (Chmaytelli 2015), a portion could also be shipped to Italy as LNG (Dipaola 2015).

Of these countries, with a new natural gas pipeline project underway and strong production growth over the last decade, Azerbaijan is best positioned to increase exports to Europe (Chyong, Slavkova and Tcherneva 2015). In contrast, while Algeria has historically been the second largest external natural gas supplier to Europe after Russia, its exports have been declining over the last decade and its export potential is expected to continue to deteriorate going forward as domestic demand increases and production declines (Chyong et al. 2015). Nigeria's exports have doubled over the last decade but in recent years it has focused increasingly on Asia as an LNG destination, with Europe's share of LNG exports falling from 65 per cent in 2005 to 32 per cent in 2015 (IEA 2016d). While it has recently proposed increasing exports to Europe, it is facing significant obstacles and delays in developing proposed additions to its export capacity (NewsBase 2014). Last, while Libya and Egypt have growing export potential both countries also have political instabilities that have previously contributed to supply disruptions (Chyong et al. 2015). With the potential for similar disruptions in the future, neither country is likely to be a secure long-term supply source of natural gas.

3. CANADIAN LNG EXPORT CAPABILITIES

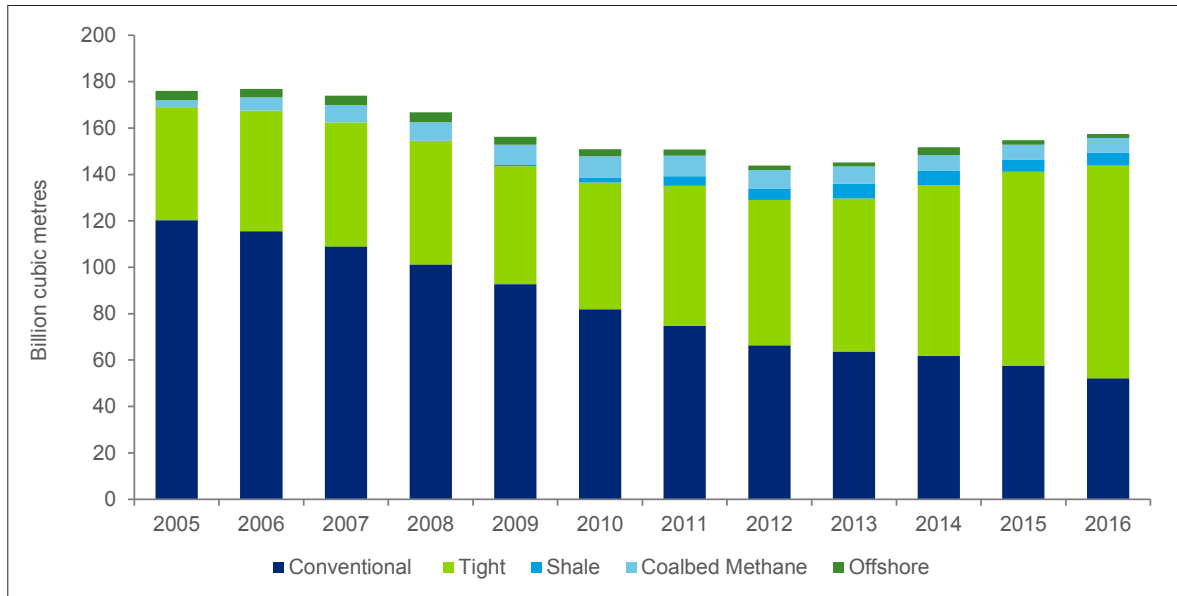
Overview

Despite significant reserves, Canadian natural gas production steadily declined from 2006 to 2012, precipitated by rapidly growing production from shale gas reservoirs in the United States. The increase in U.S. production resulted in both a decline in the North American price of natural gas as well as a decline in U.S. demand for Canadian natural gas exports. Canadian production has started to increase in recent years as technological advances and falling costs have led to an increase in the production of gas from tight and shale gas reservoirs. This trend is expected to reverse again in the short run, however, and production is not expected to start increasing again unless Canadian producers are able to secure access to higher priced overseas markets for natural gas through the development of LNG export projects. This section will consider the feasibility of Canadian LNG exports to Europe by exploring in more detail domestic production trends and forecasts, as well as Canada's current and anticipated infrastructure for natural gas export from the East Coast.

Canadian Natural Gas Production and Exports

Canadian natural gas production is concentrated primarily in Western Canada, which accounted for an annual average of 98 per cent of total production from 2005 to 2016. Production has been increasing since 2012, primarily as a result of natural gas extracted from tight and shale gas reserves in British Columbia and Alberta. Production from these reserves has increased significantly as technology developments in horizontal drilling and hydraulic fracturing have reduced production costs (NEB 2013). From 2005 to 2016 production increased by 88 per cent, rising from 48.7 to 91.7 BCM per year. This production increase has helped to offset declining production from conventional and offshore reserves.

FIGURE 18 ANNUAL CANADIAN NATURAL GAS PRODUCTION BY RESOURCE TYPE



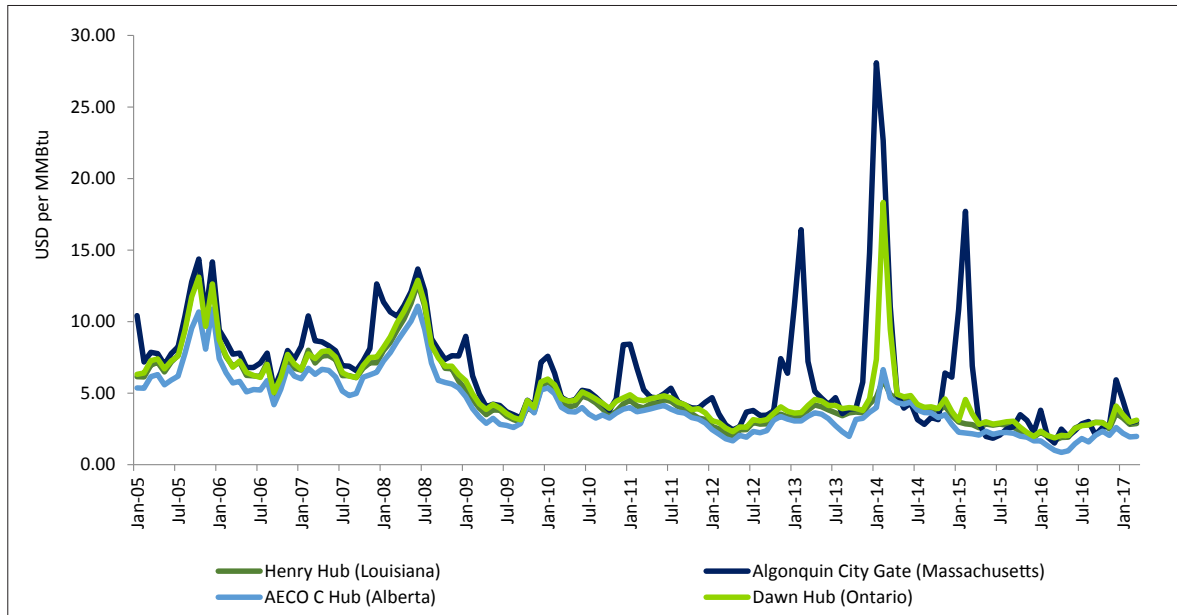
Source: National Energy Board (2017a).

The decline in natural gas production from offshore and conventional reserves has been driven by depleted reserves as well as lower gas prices that are a result of rapidly increasing natural gas production from shale and tight gas reserves in the United States. This rapid growth in U.S. production contributed to a downward trend in North American natural gas prices that first started in 2005 (Figure 19). Prices appeared to be recovering from 2007 to 2008, driven by rising U.S. demand that outpaced the growth in production, as well as a growing LNG market and high prices in Asia that attracted LNG imports away from the U.S. (Davis and Gold 2008). However, prices came crashing down in the wake of the 2008/2009 recession as production continued to grow and demand sharply declined. Rising U.S. production has continued to outpace demand since then, creating an environment of over-supply in North American markets. As a result, North American natural gas prices have remained steadily depressed at levels that are significantly lower than the prices in global markets.

Canada does not currently have any liquefaction export facilities for natural gas. As a result, Canadian producers have not been able to take advantage of higher global natural gas prices and have instead been constrained to the United States as their sole natural gas export market. Canada's level of exports is therefore largely influenced by U.S. demand and production. Although U.S. demand has increased significantly over the last decade, it has been outpaced by U.S. production. Specifically, from 2005 to 2015, U.S. consumption of natural gas increased by 24 per cent, rising from 623.4 to 773.2 BCM annually (U.S. EIA 2017d). Over this same period, U.S. dry production¹⁴ of natural gas increased by 50 per cent, rising from 511.1 to 766.2 BCM annually (U.S. EIA 2017c).

¹⁴ Dry natural gas production is equal to marketable production minus extraction losses (U.S. EIA 2017a).

FIGURE 19 NORTH AMERICAN NATURAL GAS PRICES (MONTHLY)



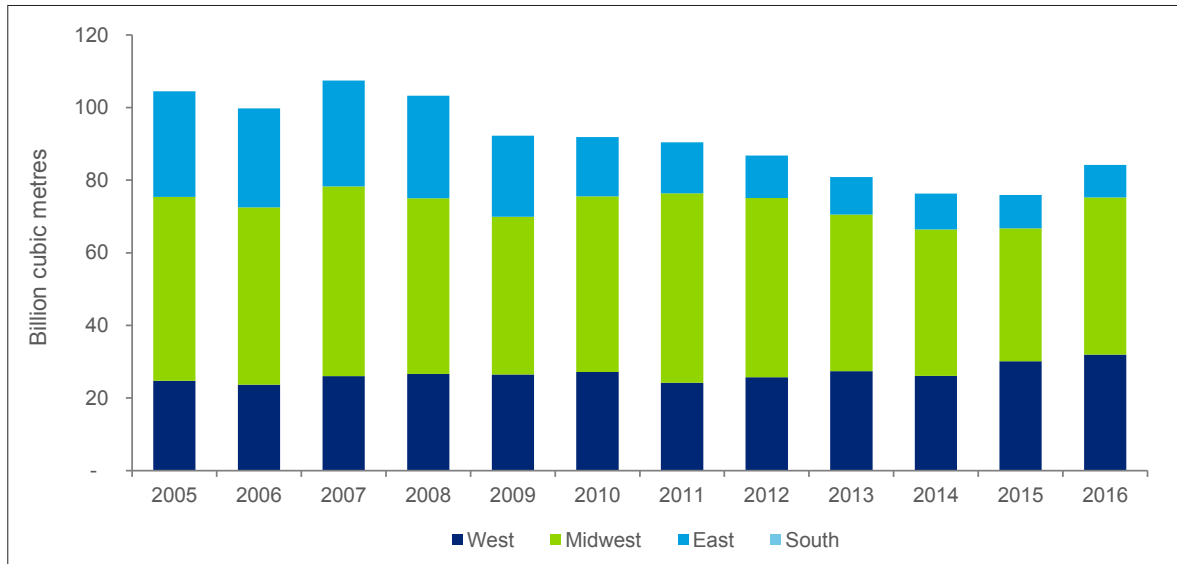
Source: Bloomberg (2017a).

Note: The monthly average spot price at the Algonquin City Hub in Massachusetts tends to spike in the winter months as a result of pipeline constraints that are exacerbated by high demand for natural gas for heating (U.S. EIA 2014a). The largest spike occurred during the “polar vortex” of 2013/2014, reaching a monthly average high of US\$25.52 per MMBtu in January 2014. The unusually cold temperatures in winter 2014 also impacted natural gas prices at the Dawn Hub in Ontario which spiked to a monthly average high of US\$18.36 in February 2014.

With the growth of U.S. production far outpacing the growth in U.S. consumption, Canadian exports to the U.S. have unsurprisingly declined in recent years, dropping from 104.5 BCM in 2005 to approximately 83.2 BCM annually in 2016 (Figure 20). In addition to displacing Canadian natural gas exports to the U.S., the increase in U.S. natural gas production has also displaced western natural gas consumption in Eastern Canada. Specifically, data from Statistics Canada (2017b) show inter-regional transfers of natural gas to Ontario declined by 61 per cent from 2005 to 2015 (-21.3 BCM) while imports increased by 100 per cent (+9.4 BCM). Although Statistics Canada does not provide data on the source of transfers to Ontario, Alberta is the only province with a large negative outflow of natural gas, suggesting it is the primary domestic source of interprovincial natural gas transfers for all provinces except the Maritimes.¹⁵

¹⁵ Statistics Canada data indicate all natural gas transfers in the Maritimes occur within the region. Specifically, positive inter-regional transfers for New Brunswick are exactly equal to negative inter-regional transfers for Nova Scotia. Statistics Canada does not report any inter-regional transfers for Prince Edward Island and Newfoundland and Labrador.

FIGURE 20 ANNUAL CANADIAN NATURAL GAS EXPORTS TO U.S. REGIONS



Source: National Energy Board (2017b).

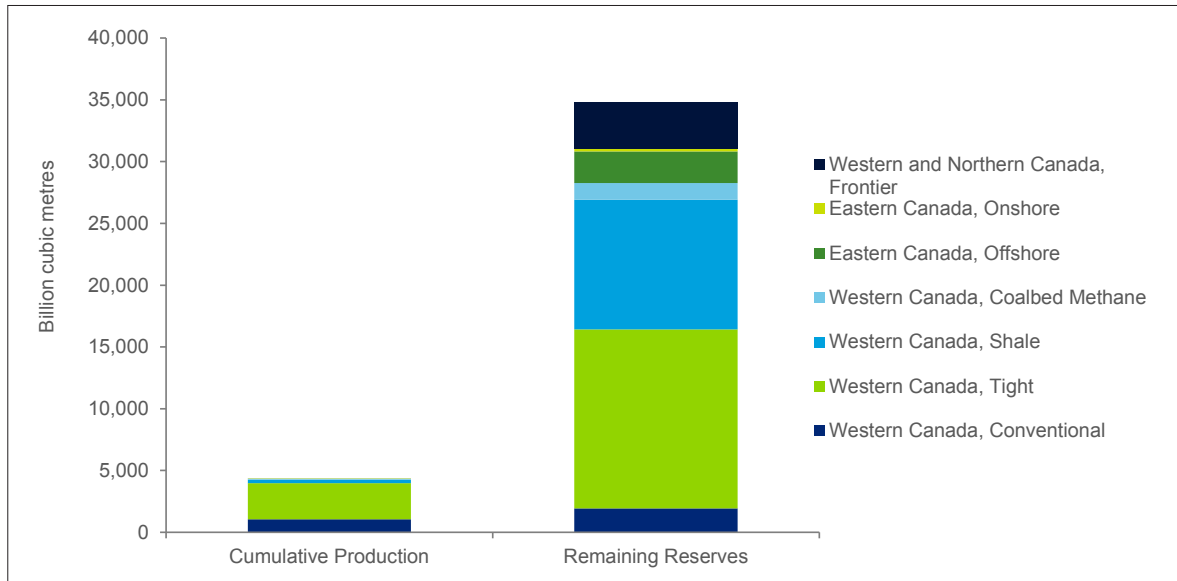
Canadian Natural Gas Production Outlook

The most recent outlook for Canadian natural gas production that assumes LNG exports is the National Energy Board’s (NEB) forecast, *Canada’s Energy Future 2016 – Energy Supply and Demand Projections to 2040, An Energy Market Assessment* (NEB 2016a).¹⁶ The complete outlook was released in January 2016 and looks at future markets for Canadian oil and gas under six scenarios. The baseline projection is referred to as the “reference case” scenario and the additional scenarios consider uncertainties with respect to oil pipeline capacity (“constrained” scenario assumes no new major crude oil pipelines), oil and gas prices (“high price” and “low price” scenarios that assume higher and lower long-term prices) and LNG market uncertainty (“high LNG” and “no LNG” scenarios that assume higher and no LNG exports from Canada). An updated outlook for the reference, high-price and low-price scenarios was released in October 2016 (NEB 2016b). We will focus the discussion that follows on the reference case scenario from October 2016, as well as the high-LNG and no-LNG scenarios from January 2016.

The NEB’s reference case forecast for natural gas production anticipates that only 11 per cent of Canada’s marketable reserves will be produced by 2040 (Figure 21). Looking at the time trend, total Canadian natural gas production is expected to decline through to 2020, grow steadily through to the late-2020s and then hold relatively constant through to 2040 (Figure 22). Tight and shale gas production is expected to grow over this entire period while conventional production is expected to continue its gradual decline. Eastern Canada offshore production is also forecast to decline and by 2040 is expected to account for only a negligible amount of total Canadian production.

¹⁶ The most recent NEB forecast, *Canada’s Energy Future 2017: Supply and Demand Projections to 2040* was released in October 2017. We opt not to use this forecast, however, as it assumes that Canada will not have any LNG exports over the forecast period. As a result, projected production volumes in this most recent forecast are not reflective of the levels that would likely accompany an LNG export industry.

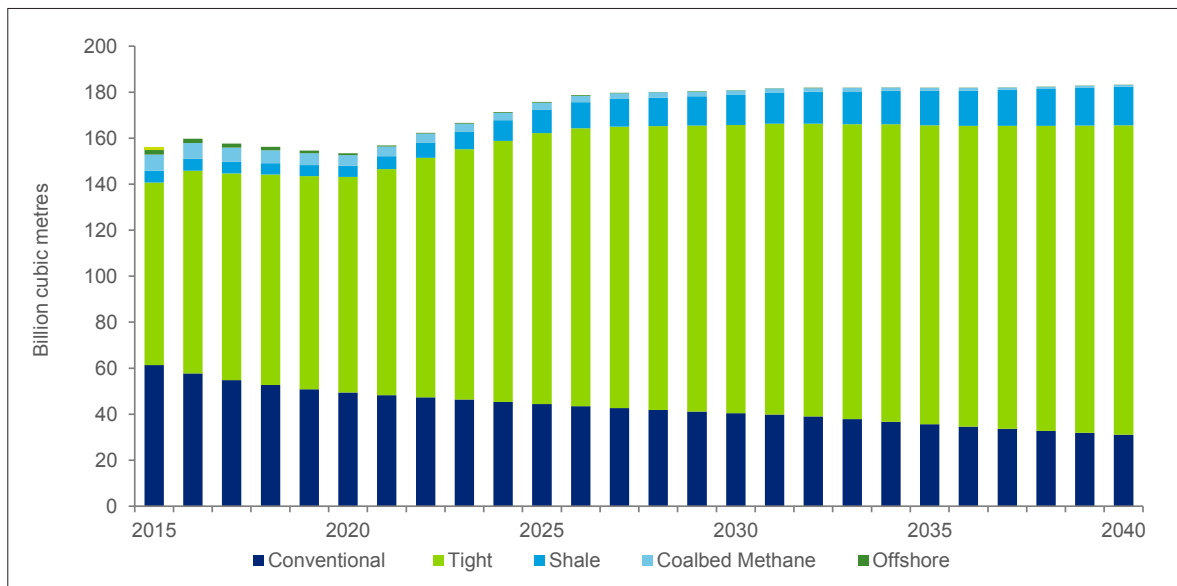
FIGURE 21 CANADIAN NATURAL GAS CUMULATIVE PRODUCTION AND RESERVES BY 2040



Source: National Energy Board (2016b).

Note: NEB reserves include estimates of natural gas reserves that are technically and economically recoverable. Estimated reserves in 2040 therefore vary depending on both anticipated production and the anticipated price of natural gas.

FIGURE 22 CANADIAN NATURAL GAS PRODUCTION OUTLOOK BY RESOURCE TYPE

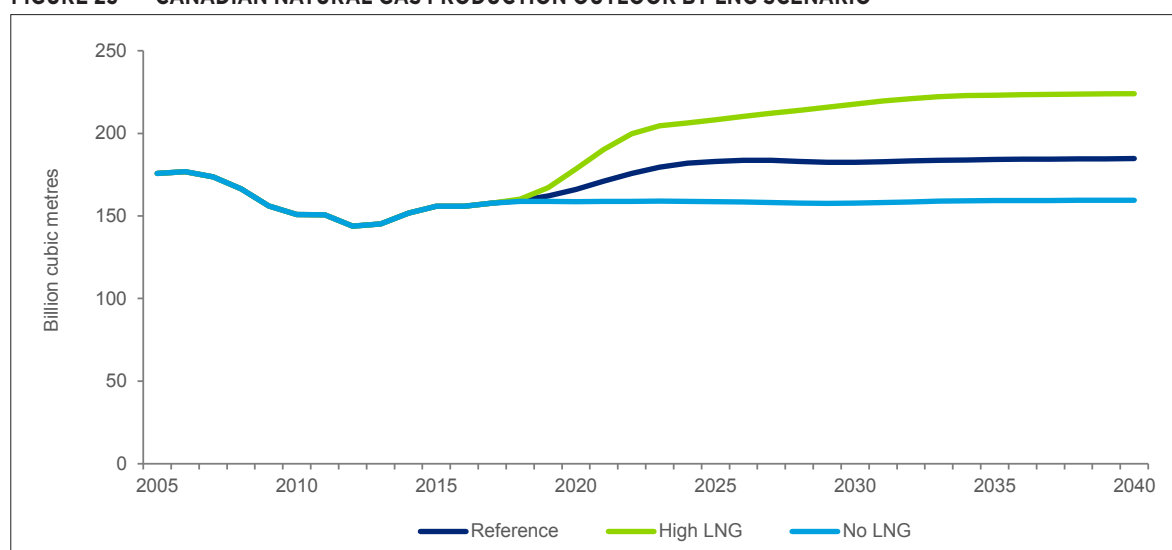


Source: National Energy Board (2016b).

A significant determinant of Canadian natural gas production in the NEB forecast is access to export markets. Declining Canadian natural gas production in the short term can be explained by rising domestic production – and thereby declining demand for imports – in the U.S. The decline in Canadian natural gas production is reversed in 2021, with the increase in production driven by the assumed start of LNG exports from British Columbia’s coast. Exports are forecast to be 5.1 BCM annually in 2021 and are expected to grow by this same amount for five years, reaching 25.6 BCM annually in 2025 (NEB 2016b). These exports help to support the growth in total natural gas production through to the late 2020s and the maintenance of production at these levels through to 2040.

The October 2016 update to the NEB outlook does not explicitly consider the possibility of LNG exports from Canada’s East Coast to Europe. However, the LNG scenarios from the complete outlook in January 2016 indicate that Canada’s natural gas production will be strongly influenced by its LNG export capacity. Specifically, the “High LNG” scenario assumes that Canadian LNG export capacity reaches 62 BCM annually by 2030, more than twice the capacity (25.6 BCM) from the reference case scenario. In contrast, the “No LNG” scenario assumes that Canada does not have any LNG exports prior to 2040. These alternate scenarios have a significant impact on the forecast production paths of Canadian natural gas (Figure 23). Most notably, in the High LNG scenario, natural gas production is expected to grow faster, and total production in 2040 is forecast to be 20 per cent higher (+39.2 BCM) than in the reference case scenario. In contrast, in the No LNG scenario production is expected to stay relatively constant throughout the forecast period.

FIGURE 23 CANADIAN NATURAL GAS PRODUCTION OUTLOOK BY LNG SCENARIO

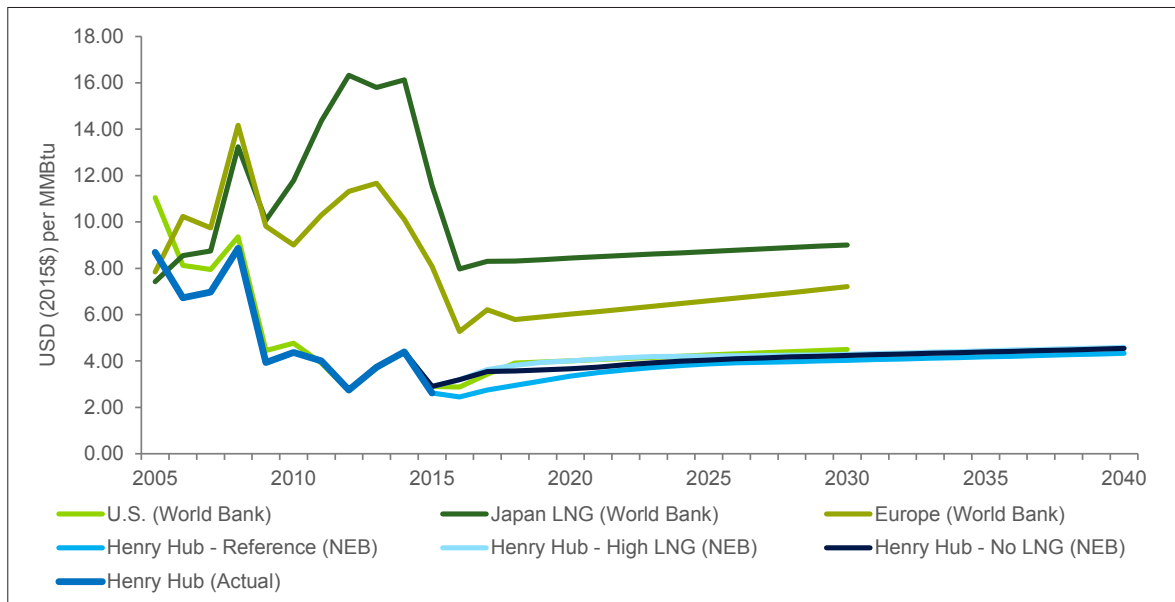


Source: National Energy Board (2016a).

Note: The reference case scenario production path is from the complete January 2016 outlook which assumed LNG exports started in 2019 and did not show a temporary decline in production from 2015 to 2021.

The responsiveness of Canadian natural gas production to LNG export capacity is indicative of the impact of gaining access to higher priced natural gas markets. With no LNG export capacity, Canadian producers only have access to the North American price for natural gas. The benchmark price for North American natural gas is the Henry Hub, which is significantly lower than historical and expected natural gas prices in Asia and Europe (Figure 25). Although LNG export capacity does not have a significant impact on the North American price of natural gas, it allows Canadian producers to access higher prices in overseas markets and therefore incentivizes higher production.

FIGURE 24 NATURAL GAS PRICE OUTLOOK (2015 USD)



Source: National Energy Board (2016a, 2016b), Federal Reserve Bank of St. Louis (2017), and World Bank (2017a, 2017b).

Note: World Bank prices for Europe, Japan and the U.S. are reported by the World Bank in real 2010 US dollars and converted to 2015 USD using the GDP price deflator for the U.S. The actual Henry Hub price and the Henry Hub prices from the NEB scenarios are reported by the NEB in real 2015 US dollars.

In addition to natural gas prices and LNG export capacity, Canada’s future natural gas production may be influenced by the regulatory environment. New federal methane regulations in the oil and gas sector will be implemented between 2020 and 2023, and impose new costs on the industry (Government of Canada 2017). Alberta is also introducing new methane regulations (Government of Alberta 2017). In addition, some shale and tight gas resources may remain undeveloped due to continued regulatory and public perception challenges with hydraulic fracturing. The NEB’s January 2016 outlook notes this risk, stating: “industry, government, and various groups in many jurisdictions continue to monitor aspects of multi-stage hydraulic fracturing. These include the amount of fresh water used in the fracturing process, the risks to ground water, and the chemical composition and safe disposal of fracturing fluids. Changing rules and regulations in these areas could affect the pace and level of drilling activity” (NEB 2016a).

The extent of a potential regulatory impact on natural gas production will be largely determined by jurisdiction. Specifically, the largest impacts would be observed if British Columbia or Alberta were to adopt and enforce stricter regulations. However, similar to jurisdictions in Europe, they are facing increasing public opposition to hydraulic fracturing and pressure to ensure regulations are sufficient and keep pace with emerging observations and research on the impacts of hydraulic fracturing. For example, increased seismic activity related to a hydraulic fracturing operation in northwest Alberta resulted in a new order from the Alberta Energy Regulator in mid-2015 requiring increased seismic monitoring in the area and an immediate shutdown of operations when an earthquake reaches a magnitude of 4.0 or higher (Alberta Energy Regulator 2017). The operation was subsequently shut down for nearly three months in early 2016 as the result of a 4.8 magnitude earthquake in January (Kent 2016).

In Eastern Canada, the regulatory environment for hydraulic fracturing is significantly less favourable. There are currently moratoriums on onshore hydraulic fracturing in Quebec, New Brunswick, Nova Scotia and Newfoundland and Labrador (Seguin and Marotte 2013; Bissett 2014; MacDonald 2014; Government of Newfoundland and Labrador 2016). Additionally, the provincial NDP in Ontario has called for a similar ban in that province (Leslie 2015). Although the NEB

forecast does not explicitly acknowledge these moratoriums, it forecasts zero production from Eastern Canada onshore reserves (those requiring hydraulic fracturing) in all scenarios.

The impact of these moratoriums on national natural gas production is likely to be limited as they apply primarily to onshore reserves in Quebec and the Maritimes. In its reference case scenario, the NEB estimates marketable reserves in these areas to be 226 BCM, which is less than one per cent of Canada's total reserves. This suggests that even if the moratoriums were to be lifted, production from these reserves would not be significant from a national perspective. Regionally, however, the moratoriums may have a much larger impact. Specifically, the Maritimes do not have any direct natural gas pipeline connections with the rest of Canada (NEB 2016c).¹⁷ As a result, Nova Scotia, New Brunswick and Prince Edward Island have historically relied primarily on Nova Scotia offshore production to satisfy domestic demand.¹⁸ With offshore production falling, however, the gap between supply and demand decreased to nearly zero in 2016. Demand is forecast to vary between 1.6 and 2.1 BCM per year annually between 2016 and 2040, while offshore production is expected to continue to decline. Any additional development and production from offshore reserves is considered speculative, and in all scenarios of its outlook the NEB forecasts that only 1.3 per cent of the natural gas in offshore reserves will be produced (NEB 2016b).¹⁹ Continued moratoriums on onshore production will therefore heighten the need for these provinces to identify alternative sources of natural gas supply for both domestic consumption and potential export.

Canadian Natural Gas Infrastructure

Six companies have received licences from the NEB to export Canadian-sourced natural gas as LNG from the East Coast (NEB 2018).²⁰ Two of these projects are in Quebec, one is in New Brunswick and the remaining three are in Nova Scotia (Figure 26). Subsequent to receiving its export licence, however, the Canaport project in New Brunswick announced that it would not be proceeding due to a lack of interest from investors (Jones 2016). This leaves five possible projects currently under development. These projects are Stolt LNGaz Inc. and Energy Saguenay in Quebec, and Goldboro LNG, A C LNG and Bear Head LNG in Nova Scotia.

Proposed LNG export liquefaction capacity from these projects is 47 million tonnes per annum, corresponding to approximately 64 BCM of natural gas. Based on the original export applications to the NEB, East Coast liquefaction capacity for export was expected to first be available in 2018 and full capacity reached in 2025. As of the end of 2017, however, none of the proposed projects have reached a positive final investment decision. While it is possible that Stolt LNGaz Inc., a small-scale plant proposed for Quebec and intended primarily for domestic LNG, could be operational by 2020, all other projects have amended their proposed start dates to between 2022 and 2024 (Figure 26). Based on these new start dates, full capacity of all facilities would not be reached until 2029 at the earliest.

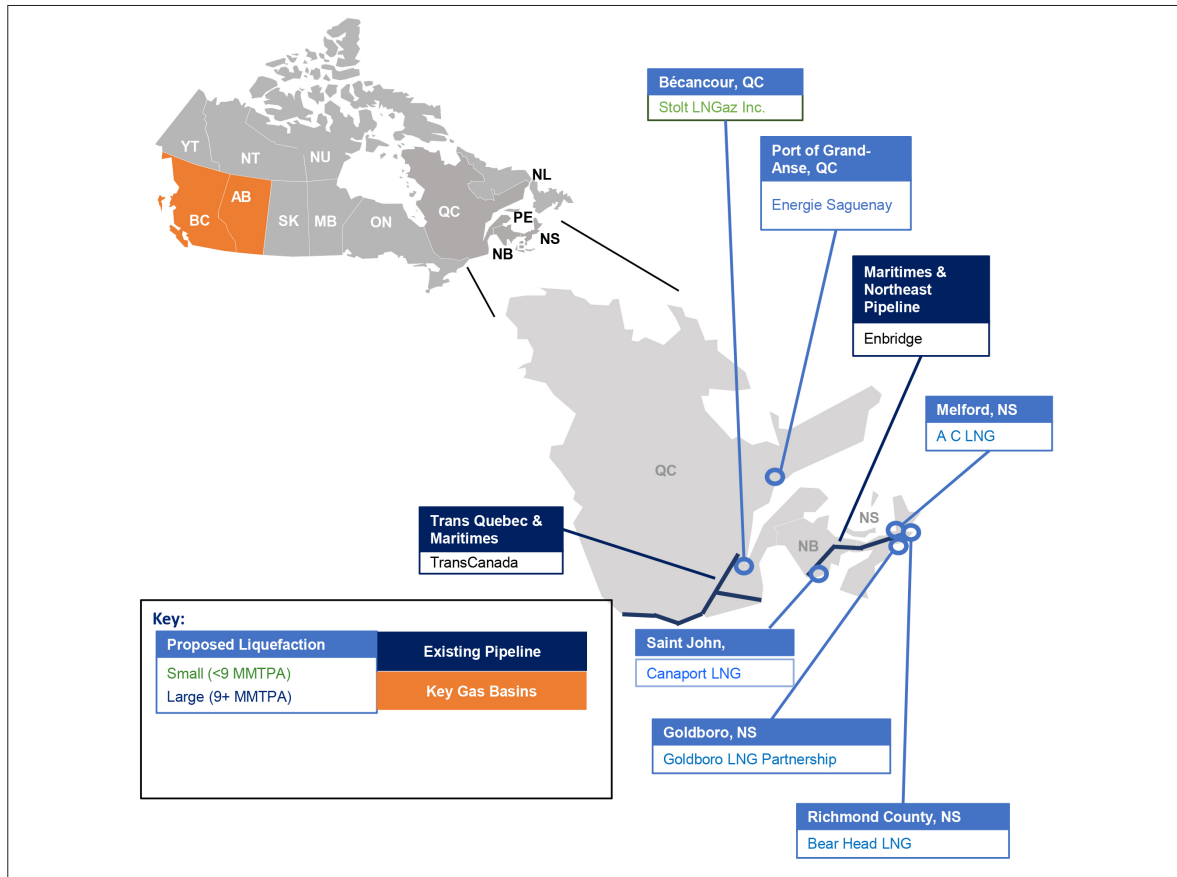
¹⁷ As discussed later in the main text, onshore Canadian production can only reach the Maritimes via a circuitous routing that requires transport through the U.S. and the transfer of natural gas along at least four separate pipelines.

¹⁸ New Brunswick additionally has access to international natural gas supplies through the Canaport LNG import facility that opened in 2009 (Canaport LNG 2009). Newfoundland and Labrador is further isolated with no access to external sources of natural gas supply from either the rest of Canada or the other Maritime Provinces. Consumption of natural gas outside of the oil and gas industry, however, is virtually zero.

¹⁹ In 2013, the NEB deemed Atlantic offshore production to be uneconomic (NEB 2013). As prices have remained low and are forecast to remain low for the foreseeable future, this conclusion is unlikely to change.

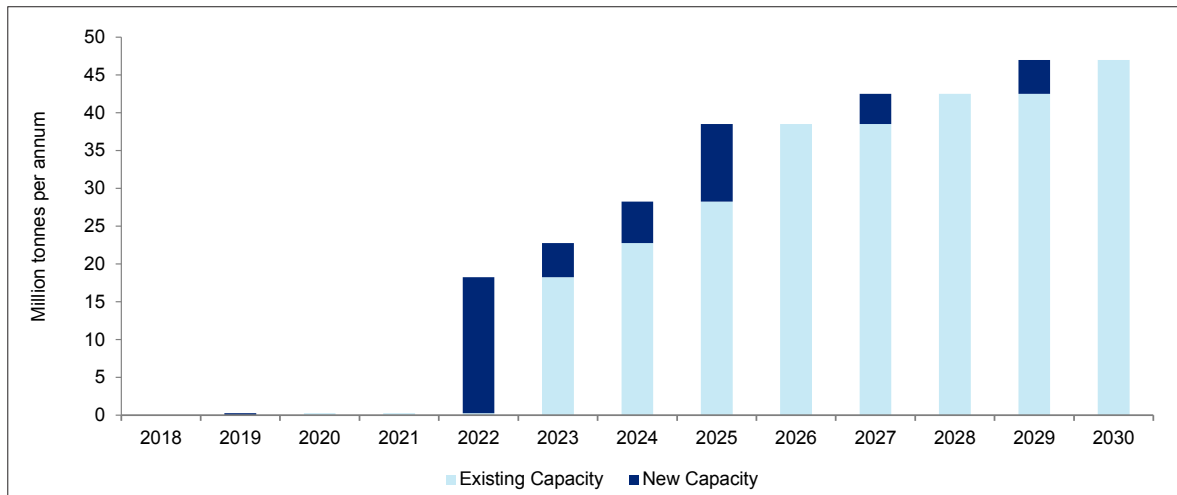
²⁰ Specific details about the projects are provided in Appendix C.

FIGURE 25 PROPOSED EAST COAST NATURAL GAS LIQUEFACTION FACILITIES AND PIPELINES



Source: National Energy Board (2018).

FIGURE 26 PROPOSED EAST COAST LNG LIQUEFACTION CAPACITY



Source: National Energy Board (2018) and project websites. See Appendix C for a full list of sources.

Note: The export ramp-up data in this figure are generally based on the projected timelines provided in the original export licence application of each project to the National Energy Board. The timelines have been shifted to match the most recent available start date estimates from project websites. For A C LNG the export volumes per phase have also been adjusted to match currently available information on the project website.

One of the largest challenges facing LNG projects on the East Coast is identifying sources of natural gas supply and obtaining access to this supply. While proposed West Coast LNG projects can rely on natural gas production from the Western Canadian Sedimentary Basin, the East Coast does not have similarly vast reserves. In addition, as noted previously, Eastern Canada is facing moratoriums on development of onshore shale gas reserves in New Brunswick, Nova Scotia, Newfoundland and Labrador and Quebec, and production from offshore reserves is rapidly declining. As a result, the majority of the natural gas supply for these facilities will most likely need to come from Western Canada and the northeastern U.S. (particularly the Marcellus shale gas play in Pennsylvania).

The two primary pipelines carrying natural gas from Western Canada to Eastern Canada are TransCanada's Canadian Mainline and the Alliance and Vector pipelines (Figure 27). The TransCanada Mainline starts in Alberta and terminates in Quebec. It is supplied primarily by TransCanada's NGTL system that runs through Alberta and into northern British Columbia. The portion of the TransCanada Mainline running from Alberta to central Ontario includes four to six pipes with total capacity ranging from approximately 100 to 195 MCM per day (NEB 2016c). The Alliance pipeline runs from northern British Columbia to Chicago while the Vector pipeline runs from Chicago to the Dawn Hub in southwestern Ontario. Capacity on the Alliance pipeline is 49 MCM per day and capacity on the Vector pipeline is 37 MCM per day (NEB 2016c; Vector Pipeline 2017).

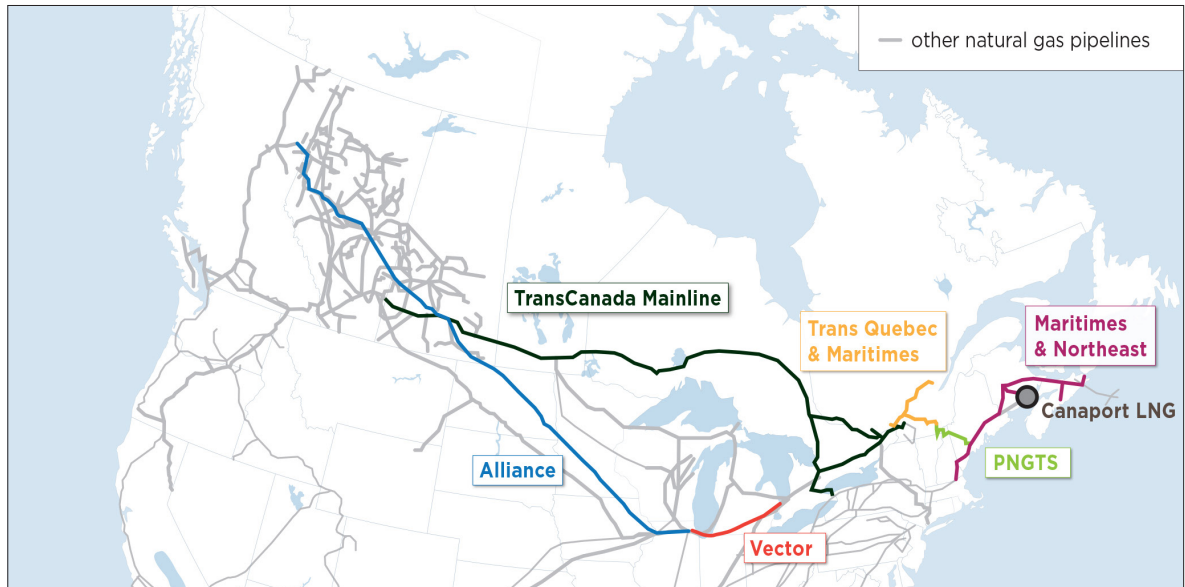
The Canadian Mainline is the most likely pipeline to carry western natural gas to the East Coast for export. In addition to extending further east, it has operated significantly below capacity in recent years – averaging only 43 per cent on the Prairies segment, 60 per cent on the northern Ontario segment and 46 per cent on the Eastern Ontario Triangle in 2015 (NEB 2016c). This is attributable to a number of factors including increased natural gas imports from the U.S., declining natural gas production in Western Canada from 2006 to 2012 and increased demand for natural gas in Alberta, which has limited the quantities available for export. A narrowing of the price differential between Alberta and Ontario pricing hubs has also made it less economical to transport natural gas from west to east. Last, with all of the other factors contributing to lower pipeline usage this has correspondingly led to higher pipeline tolls, further exacerbating the economics of shipping natural gas east.

TransCanada's Energy East proposal was born, in part, out of the low utilization rates of the Canadian Mainline. The project proposed to convert one of the Canadian Mainline pipes into an oil pipeline, diminishing natural gas transmission capacity by 31 MCM per day (16 per cent) in the Prairies segment, 42 MCM per day (42 per cent) in the northern Ontario lines and 31 MCM per day (36 per cent) in the Eastern Ontario Triangle (Energy East Ltd. 2016). With the cancellation of Energy East, the excess capacity is likely to persist in the future.

The Alliance and Vector pipelines are less likely to be used to move western natural gas to the East Coast for export. In addition to not extending to the East Coast, the system generally operates near capacity, with utilization on the Alliance pipeline averaging 99 per cent in 2015 (NEB 2016c).²¹ This high capacity utilization rate is largely because the pipelines run through the U.S. As a result, in addition to western Canadian natural gas heading to Eastern Canada, the pipelines also carry western Canadian natural gas exports to the U.S. and U.S. exports of natural gas to Eastern Canada.

²¹ In March 2017 Alliance Pipeline issued a call for expressions of interest in a potential expansion that would increase the pipeline capacity by approximately 30 per cent per day (Alliance Pipeline 2017a). As of spring 2018 Alliance has announced a potential in-service date of November 2021. A final decision on whether to proceed with the expansion, however, will depend on commercial support and regulatory approval (Alliance Pipeline 2018). Even if the expansion proceeds, however, without a corresponding expansion in the Vector pipeline it is unlikely the additional capacity could be used to serve East Coast LNG export facilities.

FIGURE 27 CURRENT NATURAL GAS TRANSPORTATION INFRASTRUCTURE



Source: adapted from Canadian Energy Pipeline Association (2013).

Of the five LNG projects under development for Canada's East Coast only a single project – Stolt LNGaz in Quebec – has direct access to a current Canadian pipeline that supplies western Canadian natural gas supply. The second project in Quebec – Énergie Saguenay – proposed in its export licence application the construction of a 600-kilometre pipeline that would link its facility with the Canadian Mainline in eastern Ontario. Unlike proposed pipelines linking West Coast facilities with natural gas supply sources in northern British Columbia and Alberta, however, this pipeline has not been formally put forward outside of the project's export application.

Proposed LNG export facilities in Atlantic Canada all identify the existing Maritimes & Northeast pipeline (M&NP) as a primary source of natural gas supply. The M&NP can currently provide direct natural gas supply to the proposed sites of both the Goldboro and A C LNG facilities. The proposed site of the Bear Head LNG facility, in comparison, is located approximately 60 kilometers from the M&NP. The project has accordingly proposed and received approval to build the Bear Paw Pipeline, a 62.5 kilometer lateral pipeline that will connect the Bear Head LNG site to the M&NP.

The M&NP has a capacity of 16 MCM per day and was originally built to transport natural gas from north to south; moving it from offshore developments in Nova Scotia to delivery points in Nova Scotia, New Brunswick, Maine, New Hampshire and Massachusetts (Maritimes & Northeast Pipeline 2017). With production from offshore reserves falling it has more recently started transporting natural gas from the Canaport LNG receiving and regasification terminal that opened in Saint John, New Brunswick in 2009 (NEB 2016c). Even with this additional supply source, however, the average capacity utilization was only 45 per cent in 2015 (NEB 2016c).

In addition to carrying natural gas from north to south over its entire system, the M&NP can carry natural gas from south to north starting from its juncture with the Portland Natural Gas Transmission System (PNGTS) in Portland, Maine. This allows natural gas from the Dawn Hub in Ontario to reach the Maritimes during periods of low natural gas production. Although it

requires a circuitous route that includes a minimum of four separate pipeline systems in the U.S. and Canada,²² this routing also allows western Canadian natural gas to reach proposed East Coast export facilities.

The Atlantic Bridge project, for which the pipeline owner Enbridge (formerly Spectra Energy) received approval in January 2017, will result in the M&NP being bi-directional over its entire system. Parts of the project began service in November 2017 and once fully operational it will allow the M&NP to carry natural gas produced in the northeast U.S. to the Maritime Provinces (Enbridge 2018).

Canadian LNG projects planning to export U.S.-produced natural gas must obtain a permit from the U.S. Department of Energy granting them re-export permission. Two of the projects in Nova Scotia, Bear Head LNG and Goldboro LNG, have applied for and received the necessary permits to re-export American gas to both countries that have a free trade agreement (FTA) with the U.S., as well as to non-FTA countries (Goldboro LNG 2016; LNG Limited 2016b). With this latter permit these facilities have the necessary permissions to re-export U.S.-sourced natural gas to Europe.²³ The third project, A C LNG, references the possibility of sourcing natural gas supply from the United States in the project overview on its website (H-Energy 2017). As of early 2018, however, it had not submitted an export licence application to the U.S. Department of Energy.

Although two of the proposed Nova Scotia export facilities have received permits for export of U.S. natural gas, and both cite the M&NP as their primary supply source, it is unclear whether the M&NP will have available capacity to carry U.S.-produced natural gas for export. On the Atlantic Bridge project website, Enbridge notes that long-term contracts have been signed with eight shippers in the U.S. northeast and the Maritimes, all of which will be using the natural gas for domestic purposes. Additionally, Enbridge explicitly notes that: “The Atlantic Bridge Project is not designed to transport natural gas for export as liquefied natural gas (LNG). The project addresses the need for additional natural gas supplies in New England and the Canadian Maritime provinces” (Enbridge 2017d). Even without existing shipping agreements for domestic natural gas use, the capacity of the M&NP (16 MCM) falls short of the proposed individual export capacities of all three proposed Nova Scotia facilities.²⁴ Further, if all the projects were to go ahead, then the M&NP would only be able to supply 11 per cent of their cumulative capacity. This strongly suggests that additional natural gas transportation infrastructure will still be required.

In addition to concerns around natural gas supply, recent developments are further casting doubt on the ability of Canada’s nascent LNG industry to realize its potential. First, the vast differential between European, Asian and North American natural gas prices observed from 2011 onwards has started to close, undermining Europe’s attractiveness as an export market. Second, the current low price of oil limits the profitability of LNG under oil-linked contracts. This has been reflected in the delaying or cancellation of proposed projects in other jurisdictions, such as Australia’s Browse LNG (Kennedy 2016). Similarly, and most concerning for proposed East Coast Canadian facilities, was the cancellation of the Canaport project in New Brunswick in spring 2016 (Jones 2016). The Canaport project was a brownfield LNG export project that would make use of existing

²² Specifically, western Canadian natural gas brought to the Dawn Hub via the Alliance/Vector pipelines, or to northern Ontario via the Canadian Mainline, would be carried to Quebec via the Eastern Ontario Triangle portion of the Canadian Mainline. It would then be transferred to the Trans-Quebec and Maritimes pipeline near Montreal, carried south and exported to the PNGTS at the Quebec/New Hampshire border. The PNGTS would carry the natural gas to southwestern Maine where it would be transferred to the M&NP and carried back north into the Maritime Provinces.

²³ A permit to export to non-FTA countries is required for export to Europe as there are currently no countries in Europe that have an FTA with the U.S. (Office of the United States Trade Representative 2017).

²⁴ The annual capacities of Nova Scotia’s three proposed LNG export facilities correspond to daily capacities of 58 MCM (A C LNG), 41 MCM (Bear Head LNG) and 37 MCM (Goldboro LNG).

infrastructure at the Canaport LNG import facility. As a result, it had one of the lowest projected capital costs of all proposed projects for Canada's East Coast and was arguably the best positioned to move forward.

A subset of proposed East Coast projects also faces the possibility of extensive federal environmental reviews, which have previously proven to be a hindrance to proposed LNG export facilities on Canada's West Coast. The Pacific NorthWest LNG project, for example, reached a conditional positive final investment decision in June 2015 but it was not until September 2016 that the project received its federal environmental approval. This concluded a nearly 3.5-year process that included five separate delays (Jang 2015). Upon review of the conditions attached to the approval the project was subsequently cancelled in July 2017 (Pacific NorthWest LNG 2017). Among the proposed East Coast LNG projects, Énergie Saguenay and A C LNG both require federal environmental approvals. The Énergie Saguenay assessment is ongoing while the review of A C LNG has not yet commenced. The remaining East Coast projects do not require federal environmental approval.²⁵

4. PROSPECTS FOR CANADIAN LNG EXPORTS TO EUROPE

Overview

With declining domestic prices impacting the economic recoverability of natural gas, Canada's natural gas production is forecast to decline in the short-term and the potential supply of natural gas to LNG export facilities is limited. Without LNG export facilities, however, Canada cannot gain access to markets with higher prices for natural gas, which would in turn motivate development of higher cost reserves. To avoid this scenario, and support continued development of Canadian resources in the medium and long term, Canada must develop access to international natural gas markets beyond the U.S. As LNG is the only means of delivering Canadian natural gas to international markets, the development of LNG export capabilities offers significant strategic value for Canada. This section will explore in greater detail the opportunities and challenges that Canada faces in developing this export capability to Europe.

Competitively exporting LNG to Europe from Canada in the short term will require overcoming a number of challenges. Foremost, existing and developing global LNG supply that will be available in the next two to three years is well positioned to service near-term European demand for LNG. In contrast, Eastern Canada is unlikely to have any significant LNG export capacity until 2022 at the earliest, positioning it as a late entrant to the European market. Furthermore, Canada's natural gas export availability will likely be constrained due to long-term declines in Eastern Canadian offshore production, as well as moratoriums on the development of onshore natural gas reserves in much of Eastern Canada. Limited infrastructure capacity to transport natural gas from western Canadian supply regions to proposed LNG projects in Eastern Canada may additionally constrain the ability of proposed projects to export Canadian natural gas from the East Coast. Rather, should any of Canada's proposed East Coast LNG export facilities move forward, it is more likely that they will be supplied predominantly by U.S. natural gas in the short to medium term.

²⁵ For Bear Head LNG and Goldboro LNG the approvals were waived on account of the project sites having previously received environmental approvals for LNG import terminals (Goldboro LNG 2013b; Smith 2015). Stolt LNGaz, in contrast, is a small-scale facility that does not meet the minimum size requirements that trigger a federal environmental assessment (Government of Canada 2012).

The Current European Opportunity & Competitive Landscape

The current opportunity for Canadian LNG exports to Europe will be predicated largely on perceived European interest to diversify its natural gas supply. The most recent Russian conflict with Ukraine, which commenced in early 2014 and is ongoing, highlights geopolitical tensions that have potential implications for the stability of European natural gas supplies from Russia that are delivered via pipeline. In response to the conflict, the European Union launched an EU Security Strategy in 2014 and identified as one of its long-term measures the diversification of supplier countries and routes for the import of natural gas and other fossil fuels (European Commission 2017a). Interest in Europe to diversify natural gas sources to become less reliant on Russian supply is also evident in the large number of LNG import terminals – 26 operating and 20 planned or under construction – in various European countries (Figure 11).²⁶

Despite the interest the EU has expressed in diversifying away from Russian supplies, Russia will remain the largest competitor to any natural gas supplier looking to enter the European market. By a significant margin, Russia is the largest external supplier of natural gas to Europe. In 2015, European countries imported 186 BCM of natural gas from Russia, accounting for one-third of consumption and nearly two-thirds of imports from known sources external to Europe (IEA 2016d). Additionally, despite conflicts with Ukraine, the Russian share of Europe's natural gas supply has increased over the last decade. Looking ahead, Russia's largest natural gas producer, Gazprom, maintains numerous long-term export contracts with European purchasers (Dickel et al., 2014). Gazprom is also forecast to have a surplus of natural gas supply available to export to Europe at a low price, suggesting that Russia is in a strong competitive position to increase its exports beyond currently contracted volumes (Henderson 2016).

The IEA's "New Policies" forecast for European consumption of natural gas suggests that natural gas consumption in Europe will slowly increase over the next 30 years, reaching approximately 600 BCM in 2025 and maxing out at just over 625 BCM in 2035.²⁷ With production in Europe forecast to steadily decline over this period, the gap between production and demand could rise from 282 BCM in 2015 to 400 BCM in 2035. If we assume that the volume of Russian imports increases, but that implementation of the EU Security Strategy maintains the share of Russian imports at approximately current levels (two-thirds), then this suggests Europe will be looking to non-Russian sources for annual natural gas imports of between 90 and 135 BCM over the next 20 years.

Canada's total proposed LNG export capacity for East Coast facilities under active development is 47 million tonnes per annum, with individual facility capacities ranging from 0.5 to 13.5 million tonnes per annum.²⁸ This corresponds to a total annual export capacity of approximately 64 BCM of natural gas, and individual capacities ranging from 0.7 to 21 BCM. If all currently proposed projects implement their first phases according to projections from fall 2017, then in 2022 the East Coast would have nearly 25 BCM of export capacity and the growth to 64 BCM would likely occur over the following seven years, with maximum capacity being reached in 2029. This would position East Coast Canadian LNG facilities to serve up to approximately 40 to 45 per cent of European natural gas demand from non-Russian sources.

²⁶ The number of LNG regasification facilities is obtained from the list provided by Gas Infrastructure Europe in the December 2017 version of the "GIE LNG Map" (Gas Infrastructure Europe 2017). We do not include LNG facilities classified as "small scale."

²⁷ Authors' calculations based on projections from the *World Energy Outlook 2017* (IEA 2017).

²⁸ Information on proposed Canadian LNG facilities is available from the export applications filed with the National Energy Board (NEB 2018).

Although Canada may develop the capacity to supply Europe with LNG, and although natural gas supplies from Canada would satisfy the European Union's call for diversification of supply sources, it is worthwhile to note that Russia is likely to respond aggressively to attempts from competitors to obtain noticeable shares of the European natural gas market. Notably, Russian prices have decreased in response to competition, particularly in response to new LNG imports (Stern and Rogers 2013, 2014; Henderson and Mitrova 2015; Gramer 2017). Given Canada's role in championing sanctions against Russia – which as of July 2017 include sanctions against Russian natural gas giants Gazprom, Gazprom Neft and Surgutneftegas (Dattu and Frombone 2015; Global Affairs Canada 2016) – any sort of a noticeable entry by Canada into Europe's natural gas market may make it a distinct target for competitive or political responses.

Canada's prospective LNG exports to Europe will also face stiff global competition in an increasingly crowded competitive landscape (Winter et al. 2018). The rapid development of LNG export facilities around the world has resulted in a global oversupply that first emerged in 2015 and is expected to persist until 2019 or later (IEA 2016b). With LNG demand in Japan and Korea – historically the two largest importers of LNG – declining, current and upcoming LNG exporters are looking to identify alternative markets. Although the largest growth opportunity exists in developing Asia, Europe is also expected to become a key target market.

Countries in the Middle East and Africa will have the largest advantage in securing European market share as they are already delivering LNG to Europe competitively. The Middle East exported 21.9 BCM of natural gas to Europe as LNG in 2015, while Africa exported 21.3 BCM (IEA 2016d). Together, they accounted for 16 per cent of non-European-sourced natural gas imports, and over 90 per cent of non-European-sourced LNG imports.

A portion of Europe's LNG imports from the Middle East and Africa are part of long-term service contracts and will continue through to 2020 and beyond (GIIGNL 2016). Subject to the limitations described in Section 2, there is likely some opportunity for Europe to expand its imports from both regions. The Middle East has 10 operating LNG export terminals in three countries (Oman, Qatar and the United Arab Emirates) with a combined export capacity of 93.5 million metric tonnes of LNG per year, corresponding to approximately 127 BCM of natural gas (GIIGNL 2016).²⁹ Africa has eight operating LNG export terminals in five countries (Algeria, Angola, Egypt, Equatorial Guinea and Nigeria) with a combined export capacity of 66.4 million metric tonnes of LNG per year, corresponding to approximately 90 BCM of natural gas (GIIGNL 2016).³⁰ Additionally, Tanzania and Mozambique are actively considering the development of LNG export terminals following the discovery of significant natural gas reserves in both countries.

²⁹ The Middle East additionally has a non-operational export facility in Yemen, which has a capacity of 6.7 million tonnes per annum. Operations at the facility were stopped in March 2015 due to security concerns (LNG World News 2015).

³⁰ Africa additionally has two non-operational LNG facilities. An export facility in Libya, which has a capacity of 3.2 million tonnes per annum (MTPA), was damaged in the country's civil war and has not been operational since 2011. A second export facility in Egypt, with a capacity of 5.0 MTPA has not been operational since 2012 due to a lack of supply (GIIGNL 2015).

The United States is also a significant source of competition to Canada as an LNG supplier to Europe, and is considerably further along than Canada in the development of LNG export facilities. The Cheniere Sabine Pass terminal in Louisiana shipped its first LNG cargo in late February 2016 and its first shipment of LNG to Europe was sent to Portugal in April 2016 (Gronholt-Pedersen 2016; Shiryayevskaya, Weber and Lima 2016). Four trains at the facility are currently operating and one additional train is under construction (Cheniere Energy 2017a, 2017b). Dominion Cove Point in Maryland started operating in March 2018, with its first cargo going to the United Kingdom (Elliott 2018). The United States has an additional four LNG export facilities that have received approval from the Federal Energy Regulatory Commission (FERC) and are under construction: Southern LNG in Georgia, Cameron LNG in Louisiana, and Cheniere Corpus Christi and Freeport LNG in Texas (FERC 2017b).

All projects currently under construction are expected to be operational by the end of 2020. At this time the United States will have a total export capacity of 68.2 million tonnes per annum, corresponding to approximately 92.7 BCM of natural gas (Cameron LNG 2017; Cheniere Energy 2017b; Dominion Energy 2017a; Freeport LNG 2018; Kinder Morgan 2017). While a significant portion of this output has been contracted to customers in India and Asia, a number of companies in Europe have also entered into long-term purchase agreements with these facilities (Cheniere Energy 2016). It is anticipated that Europe could receive greater than half of LNG exports from the U.S. by 2020 (LNG World News 2017). U.S. supply, however, will likely still account for only a small share of total imports to Europe. Based on current contracts, the U.S. accounts for only 16 per cent of contracted LNG volumes to Europe in 2020, though this increases to 35 per cent in 2030 (Figure 16).

U.S. plans for LNG export further extend beyond the capacity that is currently operating or under construction (FERC 2017a, 2017b). Four of the six active projects – Sabine Pass, Cameron LNG, Freeport LNG and Cheniere Corpus Christi – have additional expansions that have been approved by FERC or are under application. Three separate projects – Southern Union-Lake Charles LNG, Magnolia LNG in Louisiana and ExxonMobil-Golden Pass in Texas – have received approval from FERC but are not yet under construction. An additional 11 U.S. East Coast facilities have been proposed to FERC, nine of which have pending applications and two of which are in pre-filing. One additional project that is located offshore in the Gulf of Mexico has been proposed to the United States Maritime Administration and the United States Coast Guard. Last, there are numerous additional projects that have applied for export licenses from the Department of Energy but which have not started the FERC process.³¹

Canadian LNG Capabilities and Competitiveness

Given Europe's proximity to Eastern Canada, it is a strong potential market for LNG exports from Canada's East Coast. Canada, however, is currently not well positioned to export Canadian natural gas to overseas markets in the short term via the East Coast. While Canada has large natural gas reserves, a significant majority remain uneconomical to produce due to persistently low North American natural gas prices and lack of access to higher priced markets beyond the U.S.

³¹ A potential LNG export facility in the United States must receive approval from both the Federal Energy Regulatory Commission (FERC) and from the Department of Energy (DOE). FERC provides authorization for the siting of an export terminal while the Department of Energy provides the facility with an export permit. The FERC process includes an environmental review and can cost a company up to \$100 million. In contrast, an export application to the DOE costs approximately \$20,000 to file. As the FERC application is significantly more expensive, it is considered a better measure of the viability of a potential project. Effective August 2014, the Department of Energy will review applications for export licences only after a project has received FERC approval. Before this change was introduced, however, a number of projects that had not started the FERC approval process received conditional approval for export. As a result, the number of projects with DOE approval exceeds the number with FERC approval (Rascoe 2014; United States Government Accountability Office 2014).

Availability of natural gas for export from the East Coast is also impacted by the moratoriums on hydraulic fracturing in place in Nova Scotia, New Brunswick, Newfoundland and Labrador and Quebec, which are limiting exploration and development of potential new reserves.

Proposed Eastern Canada LNG projects must also overcome significant infrastructure limitations. Of the five projects under active development, only Stolt LNGaz in Quebec – the smallest of the proposed projects – is in a location that currently has direct pipeline access to western Canadian natural gas. The second project in Quebec – Énergie Saguenay – will rely on construction of a 600-kilometre pipeline that connects to the Canadian Mainline in Ontario, and which has not been formally proposed outside of the project’s LNG export application. Moving forward with a formal application for the pipeline may result in a significant bottleneck as the regulatory process for pipeline approvals has become increasingly contentious in recent years.

The three LNG export projects proposed in Nova Scotia have each identified the M&NP as an initial source of supply (as noted earlier, Bear Head LNG will require construction of a pipeline lateral to connect it to the M&NP). Although by a circuitous route that goes through the U.S., the M&NP can currently supply western Canadian natural gas to Nova Scotia. With the entire pipeline becoming bi-directional upon completion of the Atlantic Bridge project the M&NP will also be positioned to carry U.S.-produced natural gas that can be re-exported from Nova Scotia LNG export facilities. As noted earlier, however, Enbridge has stated that the reversal of the southern portion of the pipeline is not intended to carry natural gas to Canada for export. Additionally, the current capacity of the M&NP falls well below the proposed export capacity of each of the individual Nova Scotia export facilities. Both these factors suggest the M&NP will require a capacity expansion if it is to carry natural gas for export.

While regional Nova Scotia communities will benefit from the economic activity of LNG export facilities regardless of whether they are supplied by Canadian or U.S. natural gas, the cross-country benefit of these export facilities – particularly to western Canadian provinces – will be significantly larger if infrastructure is in place for more significant quantities of western Canadian natural gas to reach Nova Scotia via a direct route that does not require transport through the U.S. This will require the construction of new pipelines, most likely connecting to the Canadian Mainline in Ontario or Quebec. As just discussed, any new pipelines – and particularly those that cross provincial borders – will likely face bottlenecks as a result of regulatory processes.

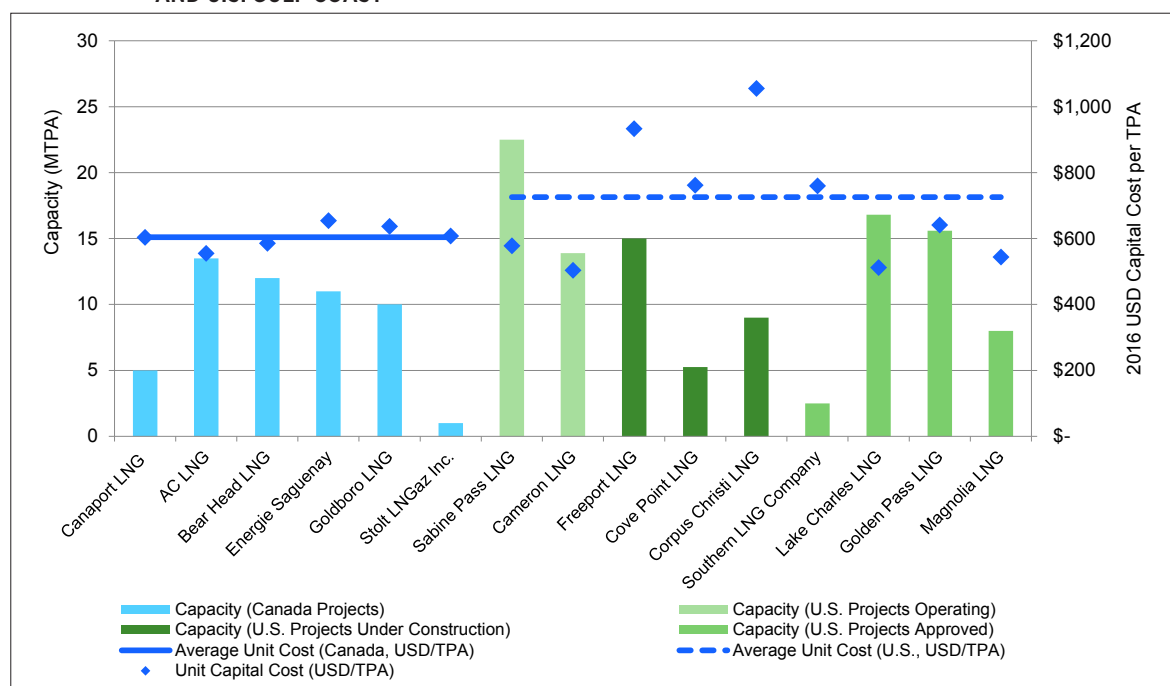
The development of proposed export projects and pipelines will further depend critically on First Nations’ engagement and participation. Current First Nations’ concerns range from environmental and cultural asset preservation to economic participation and ownership of projects. There are 28 First Nations in New Brunswick and Nova Scotia, and 40 in Quebec (Indigenous and Northern Affairs Canada 2017). A large number of these First Nations have claims to land that will be impacted by proposed LNG export projects or the pipelines that will be required to transport natural gas to these projects. As very few have treaty agreements with federal and provincial governments, the negotiation of project-specific agreements will be required for proposed export facilities and pipelines to proceed (Indigenous and Northern Affairs Canada 2013). This can be a lengthy process that could result in additional delays to proposed projects. Canada’s experience with other large energy infrastructure projects has not been positive, with multiple court cases finding the federal government failed in its duty to consult with Indigenous communities. This creates the prospect of additional risk and delays to project proponents.

Turning to financial considerations, as no East Coast LNG facilities have reached a final investment decision, available cost estimates are approximate at best. Énergie Saguenay, Stolt LNGaz, Goldboro LNG and Bear Head LNG have all made cost estimates publicly available. Cost estimates for full build-out range from US\$585 to US\$655 (2016 dollars) per tonne of annual export capacity

(TPA) (Figure 28).³² A cost estimate from a direct company source is not available for A C LNG. A review of external sources, however, suggests a cost estimate of approximately US\$555 per TPA for construction of the first phase. As the first phase of construction is typically the most capital intensive, the expected per-unit cost for the full facility would be even lower.

The average per-unit cost of construction across all proposed East Coast export facilities is US\$604 per TPA.³³ This appears to make East Coast LNG facilities highly competitive with those in the United States. Specifically, of the U.S. LNG projects operating or under construction, the estimated costs vary from US\$504 to US\$1,056 per TPA with an average cost across all facilities of US\$723 per TPA.³⁴

FIGURE 28 ESTIMATED NORTH AMERICAN LNG LIQUEFACTION PROJECT CAPITAL COSTS: EAST COAST CANADA AND U.S. GULF COAST



Source: Various project announcements. See Appendices C and D for detailed sources.

Note: The unit cost for each facility is equal to the facility’s expected capital cost divided by its annual capacity in million tonnes per annum. Among the U.S. projects, Sabine Pass LNG, Cameron LNG, Freeport LNG, Cove Point LNG, Southern LNG Company and Lake Charles LNG are all brownfield projects. In Canada, Canaport LNG is also a brownfield project while Bear Head LNG is considered a partial brownfield as site preparation work was completed for a previously proposed LNG import terminal.

It is notable that the majority of U.S. facilities are brownfield projects that are being built on the sites of existing LNG import terminals. As a large amount of infrastructure is already in place, analyses of global competitiveness in the LNG industry consistently find that U.S. brownfield developments have the lowest capital costs by a significant margin. For example, a 2014 report by

³² The cost per tonne of annual export capacity is equal to the expected capital cost of the project divided by its proposed annual export capacity in metric tonnes. When a cost range is provided for a project, the estimated cost is assumed to be the midpoint of the range. Annual capacity for the project is assumed to be the capacity at full build-out unless the only cost estimate available is for a specific project phase. Canadian cost estimates are converted to 2016 USD estimates using the price index for gross domestic product at market prices from Statistics Canada (2017c) and exchange rate data from the Bank of Canada (2017). See Appendix C for detailed sources.

³³ This is a weighted average calculation in which the average per unit capital cost for each facility is weighted by the facility’s export capacity at full build-out.

³⁴ See Appendix D for detailed sources on estimated per unit capital costs for U.S. LNG export facilities.

NERA Economic Consulting estimates a capital cost of \$544 per TPA for projects in the United States and \$1,145 for projects in Canada (NERA 2014). Similarly, although not location-specific, a 2014 report from the Oxford Institute for Energy Studies (OIES) provides estimated cost bands in a “normal cost” location of US\$600 to US\$800 per TPA for “liquefaction only” (brownfield projects) and \$1,000 to \$1,200 per TPA for a “complete facility” (greenfield projects) (Songhurst 2014).³⁵

These analyses suggest that current estimates of East Coast liquefaction costs may be overly optimistic and that actual capital costs for construction of the facilities will be higher. Notably, although it has since been suspended, the Canaport LNG conversion was estimated to have a capital cost of up to US\$600 per TPA.³⁶ As this was the only brownfield project proposed for Eastern Canada, it is reasonable to expect that it would have the lowest capital costs. Additionally, it is worth noting that most of the Canadian cost estimates date back to when the projects were first proposed (exact dates are between 2013 and 2015). As there are a significant number of variables that impact the cost of liquefaction facilities, it is not unusual for these costs to be underestimated to start.³⁷

Canada’s East Coast is consistent with the OIES definition of a normal cost location with all proposed facilities being located at or nearby established industrial areas. A number of cost advantages also exist for some or all projects, suggesting capital costs could feasibly come in toward the lower bound of the OIES estimates and perhaps even below. First, a low Canadian dollar will put downward pressure on any inputs, such as labour and electricity, that are priced in Canadian dollars. The OIES study estimates that typically 50 per cent of LNG capital costs are in local currency, making this the largest source of cost savings for Canadian projects. Labour costs may also be further reduced by a relatively depressed job market in Eastern Canada. For example, the unemployment rate in Nova Scotia in July 2017 was 7.9 per cent (Statistics Canada, 2017a), suggesting the province has spare economic capacity relative to the U.S. Gulf Coast that could keep capital costs lower.³⁸ However, working against Canadian projects are current tariffs on pre-fabricated steel LNG modules which need to be imported from Asia (Murphy 2018).

In Quebec, Stolt LNGaz and Énergie Saguenay will benefit from Quebec’s industrial electricity prices, which are among the lowest in North America (Hydro-Québec 2017), and from their proposed locations nearby populated areas (reducing the need for construction of worker camps) and existing industrial marine ports. In Nova Scotia, the Bear Head LNG facility is a partial brownfield project, located on the site of a previously proposed LNG import facility for which some initial construction work was previously completed (Government of Nova Scotia 2017a). Also in Nova Scotia, the first two phases of construction at A C LNG are proposed to be near-shore floating LNG (FLNG) units (Evaluate Energy 2015). FLNG units will often reduce the capital costs

³⁵ A “normal cost” location is defined as: “those which are typically located in industrialized areas with good infrastructure and easy access to competitively priced construction resources.” Canada’s East Coast projects are all consistent with this definition.

³⁶ From Jones (2016): “The cost of the Canaport plant conversion was estimated at between \$2 and \$4 billion [CAD] when it was cancelled in 2016.” With an anticipated capacity of five MTPA this works out to an upper bound of approximately US\$600 per TPA.

³⁷ For example, Cheniere is building two liquefaction projects on the U.S. Gulf Coast, the brownfield Sabine Pass facility and greenfield Corpus Christi facility. Prior to starting construction, Cheniere estimated a unit capital cost of \$400 per TPA at Sabine Pass and \$800 per TPA at Corpus Christi (Cheniere Energy 2011, 2012). With the first four trains at Sabine Pass now operating, and additional trains at both projects under construction, Cheniere reported in its 2016 annual report estimated capital costs that correspond to per-unit costs of \$556 to \$600 per TPA at Sabine Pass and of \$1,000 to \$1,111 per TPA at Corpus Christi (Cheniere Energy 2017b). These costs are approximately 25 to 40 per cent higher than its initial estimates.

³⁸ The aftermath of Hurricane Harvey can also be expected to influence costs in the U.S. Gulf Coast. While this is less of a consideration for facilities already under construction, the economic capacity devoted to recovery from the hurricane (and the expectation of future hurricanes of similar magnitude) may influence the feasibility of currently proposed projects on the U.S. Gulf Coast.

of a project, with most recently constructed units having a capital cost of between US\$600 and US\$1,000 per TPA (Songhurst 2016).

The capital costs of LNG export facilities are only one component of the integrated costs for LNG exports to Europe. Other costs that will affect the competitiveness of North American suppliers include the upstream supply costs of natural gas, pipeline transport (to move natural gas from its production location to the export facility), the cost of liquefaction, and shipping costs from North America to Europe (Figure 29).

As it is geographically closer to Europe, the most definitive advantage for Canada's East Coast is lower shipping costs relative to the U.S. Gulf Coast, where the majority of the proposed export facilities for the U.S. are located. Shipping costs, however, are a relatively small component of overall export costs. Although the distance from Canada's East Coast to Europe is approximately 30 to 40 per cent less than the distance from the U.S. Gulf Coast to Europe, the corresponding cost savings are not significant, amounting to just under 50 cents per MMBtu.³⁹

The larger potential cost advantage for eastern Canadian facilities is the low price of western Canadian natural gas. Natural gas at the AECO Hub in Alberta has historically sold at a discount to the North American Henry Hub benchmark in the southern United States. In 2016, for example, the AECO price averaged 85 cents per MMBtu lower than the Henry Hub price. This savings, however, could be largely offset by higher pipeline transportation costs to move natural gas across Canada,⁴⁰ particularly if new infrastructure is required. Additionally, if eastern Canadian LNG facilities export U.S.-sourced natural gas, then they are likely to pay a price that is more similar to Henry Hub, eliminating any cost advantage over U.S. Gulf Coast projects.⁴¹

Last, as just discussed, Canada's East Coast LNG facilities, almost all of which are greenfield developments, will likely face significantly higher capital costs than the more prevalent brownfield projects on the U.S. Gulf Coast. Specifically, the aforementioned NERA report estimates the capital cost of liquefaction on the U.S. Gulf Coast at \$1.83 per MMBtu (2016 USD), while in Canada the capital cost of liquefaction is estimated at \$3.86 per MMBtu. This is the largest cost wedge between projects in the U.S. and Canada, and although Canadian facilities have some small cost advantages,

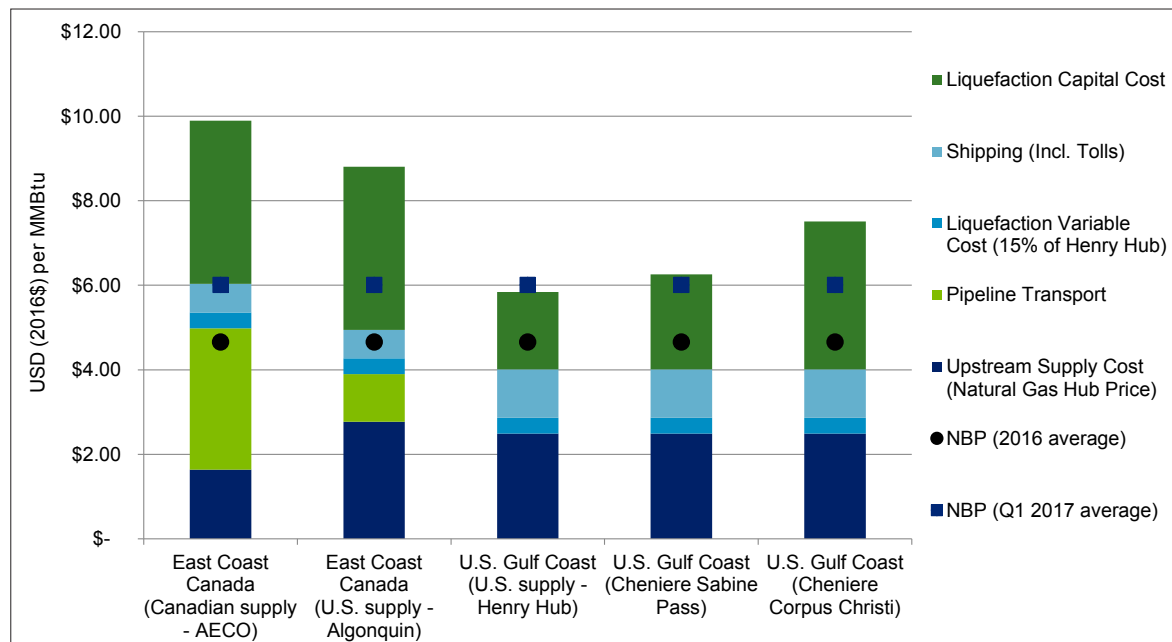
³⁹ Shipping costs for LNG are estimated using data from the Bloomberg shipping database. Specifically, monthly shipping rates per MMBtu were downloaded for 42 LNG routes (export point to import point) from May 2010 to Feb. 2017 (an exact listing of routes and their corresponding Bloomberg indices are available upon request). Distances in nautical miles for each route were either identified in the "Sea Transportation Routes" section of the GIIGNL 2014 Annual Report or were calculated using the website <http://www.sea-distances.org>. When a country has more than one LNG export (import) facility the location of the largest facility was selected as the point of export (import). We use the Bloomberg data to calculate an average monthly shipping rate for each route and then divide this number by the route distance to calculate the average shipping price per MMBtu and per nautical mile. The shipping costs reported in the Figure are equal to the average shipping price per MMBtu and per nautical mile multiplied by the distances from Point Tupper, Nova Scotia to Barcelona, Spain and from Port Arthur, Texas to Barcelona, Spain.

⁴⁰ The pipeline toll on the TransCanada Mainline is approximately 42 per cent of the total pipeline cost, and so reductions in that toll could make western Canadian gas more competitive. However, even halving the Mainline toll would only reduce the overall cost by less than 10 per cent.

⁴¹ As noted earlier, the M&NP has been cited in export permit applications as the primary supply source for U.S.-produced natural gas. The M&NP connects with the Algonquin gas transmission in northern Massachusetts where natural gas is priced at the Algonquin City Gate Hub. As shown in Figure 19, natural gas prices at the Algonquin City Gate have historically tracked closely with Henry Hub in the spring and summer months (averaging less than a four per cent differential over the last five years) while spiking in the winter months due to supply shortages. The previously referenced Atlantic Bridge project is being designed to increase natural gas flow along the Algonquin pipeline and alleviate these winter price spikes. Upon completion of the project it is reasonable to expect the Algonquin price will track closely with the price at Henry Hub throughout the entire year.

they are insufficient to overcome this differential. Correspondingly, the total integrated cost of LNG shipments from Canada (\$8.80 to \$9.90 per MMBtu) is estimated to be 50 to 70 per cent higher than shipments from the U.S. Gulf Coast (\$5.84 per MMBtu).

FIGURE 29 ESTIMATED INTEGRATED COSTS FOR NORTH AMERICAN LNG EXPORTS TO EUROPE



Note: North American prices based on average of 2016 monthly prices at the AECO, Algonquin City Gate and Henry Hub pricing hubs (Bloomberg 2017a). UK NBP prices are similarly based on the average of 2016 monthly prices and 2017 monthly prices for Q1 (Bloomberg 2017a). Port of receipt is Barcelona, Spain. Shipping costs calculated by averaging \$/MMBtu/nautical mile shipping costs over all LNG routes in Bloomberg POTN shipping database between 2010 and Q1 2017. Distances used are from www.sea-distances.org. Capital cost estimates from NERA (2014) (used for the three leftmost columns) are inflated using the Federal Reserve Bank of St. Louis GDP deflator. The two Cheniere cost estimates are based on corporate presentations (Cheniere 2016a, 2016b, 2016c). The Canadian supply cost estimates do not include carbon tax payments.

As shown in Figure 17, natural gas prices in Europe have declined since their most recent peak, and in March 2017 ranged between US\$5.14/MMBtu (Germany) and \$4.81/MMBtu (South France). The 2016 average price in the U.K. (NBP) — which historically exhibits slightly higher prices than continental Europe — was US\$4.66/MMBtu. Russian gas at the German border was priced at US\$4.95/MMBtu in March 2017, and in 2016 averaged \$4.35/MMBtu. These prices make even U.S. exports to Europe appear challenged, though presentations from Cheniere Energy suggest the Sabine Pass project is profitable even at a delivered price of US\$5/MMBtu (Cheniere Energy 2016b).

Of particular interest for Canadian projects, however, are the contracts Cheniere has pioneered at its Sabine Pass and Corpus Christi projects. The contracts have a fixed liquefaction fee with the variable cost of LNG being 115 per cent of Henry Hub (Cheniere Energy 2016a, 2016b, 2016c). Sabine Pass, a brownfield project, has fixed liquefaction fees ranging from \$2.25/MMBtu to \$3.00/MMBtu, and Corpus Christi, which is greenfield, has fixed liquefaction fees of \$3.50/MMBtu (Cheniere Energy 2016c). Several of the Corpus Christi contracts are with European utilities, such as Natural Gas Fenosa (Spain), Endesa (Spain), Électricité de France (France) and EDP (Portugal). This suggests European importers are willing to accept a slightly higher price (\$6-plus per MMBtu before transportation in Corpus Christi's case) for an alternate source of supply. These numbers give a sense of the type of contracts Canadian projects could secure, making upstream supply cost and pipeline tolls key determinants of the overall competitiveness of Canadian projects. Of additional note for this discussion is that the costs presented here do not include regasification, which should be considered given that the competition for LNG in Europe is pipeline gas, which

is already in gaseous form. Bordoff and Losz (2016) note regasification can cost between \$0.30 and \$0.40/MMBtu. However, this only matters for comparing Canadian LNG costs to European pipeline gas, and not its competitiveness to U.S. projects.

The cost estimates presented above also do not reflect carbon pricing. While this is an additional cost, how each project will be treated depends on its jurisdiction. As provinces are currently developing their climate policies, uncertainty remains. To mitigate these costs, LNG projects, as large, emissions-intensive and trade-exposed projects competing against projects in jurisdictions without carbon pricing, may be eligible for policies to address these competitiveness concerns.⁴² Of potentially greater concern to liquefaction facilities are federal and provincial methane regulations, which will impose additional costs on Canadian projects, further undermining their competitiveness.

Looking ahead, in the near term the gap between the integrated cost of U.S. and Canadian LNG exports to Europe appears likely to increase, due largely to trends in upstream supply costs and the cost of pipeline transport. This will place Canada at a greater cost disadvantage and continue to decrease its competitiveness as an LNG supplier. In particular, if the production costs of U.S. shale and tight gas continue to decline then this will translate into lower upstream supply costs for U.S. export facilities on both the eastern seaboard and the U.S. Gulf Coast. In contrast, with moratoriums on onshore shale and tight gas extraction, the higher relative cost of offshore natural gas extraction, and the higher relative pipeline costs of moving western Canadian or U.S.-sourced natural gas to Eastern Canada, eastern Canadian export facilities are unlikely to have access to similarly low-priced natural gas in the near future.

In addition to being at a cost disadvantage, Canada will face the challenge of entering the European LNG market well after the U.S. As noted earlier in this section, both Cheniere Energy's Sabine Pass terminal in Louisiana and the Dominion Cove Point LNG terminal in Maryland have begun shipping to Europe (Cheniere Energy 2016c; Elliott 2018). With the four other export facilities that are under construction, the U.S. will likely have a minimum export capacity of 57 million tonnes of LNG per year by 2020. This could be higher if additional projects that are approved, or which have pending applications, move forward. Sabine Pass LNG and Corpus Christi LNG have contracts in place with Britain, France, Italy, Portugal and Spain (Bloomberg 2017b). In contrast, while there are three eastern Canadian LNG projects that proposed commencing exports prior to 2020 in their original export applications, none of these projects has made a final investment decision. Given that construction of LNG export facilities in the U.S. has been taking three to four years, it appears very unlikely that Canada will be in a position to commence LNG exports to Europe until 2022 at the earliest.

Canadian LNG Value Proposition

Canada's fiscal and political environment, complemented by abundant resource reserves, makes Canada an attractive long-term supplier of natural gas to Europe. The primary value of Canadian-supplied natural gas to European customers is supply stability, as well as social and environmental production practices that align well with European values (Table 4). The 2016 Environmental Performance Index, which ranks countries based on their performance in protection of human health and protection of ecosystems, ranks Canada 25th out of 180 countries (YCELP 2016). This places Canada in the mix with countries in Europe, which rank from first to 47th, and roughly equal with the United States (26th) and Russia (31st). It also places Canada well ahead of Qatar (87th), Iran (105th), Nigeria (133rd), Algeria (83rd) and Libya (119th), which are likely to act as key global competitors for providing increased LNG supply to Europe.

⁴² These subsidies are also referred to as output-based allocations. For more details, see Dobson et al., (2017).

As indicated by the discussion earlier in this section, Canadian LNG export facilities hoping to secure long-term European supply contracts compete most directly with U.S. facilities. This is a result of similar characteristics between U.S. and Canadian facilities with respect to supply sources, certainty of supply, geopolitical stability and social and environmental production practices. Canada has a small edge over U.S. supply with respect to being geographically closer to Europe. The United States, however, is ahead of Canada with respect to infrastructure and a lower cost of LNG supply. These factors give the U.S. a distinct competitive edge over Canada and suggest that competing U.S. LNG supply will likely be Canada's largest barrier to entering Europe's natural gas market.

TABLE 4 COMPETITIVENESS OF NATURAL GAS EXPORTS TO EUROPE

Supply Region	Reserves/Up stream	Distance to Demand	Geopolitical Stability	Current Infrastructure	Cost/Price
Canada (East Coast)					
U.S. (Gulf of Mexico)					
U.S. (Eastern Seaboard)					
Middle East					
East Africa					
Russia					
Legend		Advantaged		Disadvantaged	

The competitiveness of Canadian LNG in comparison to other potential suppliers of natural gas to Europe is mixed. With respect to geographic proximity, eastern Canadian LNG is disadvantaged relative to natural gas supply from Russia, which can be delivered via pipeline. Canadian LNG terminals are closer to Europe than LNG terminals in East Africa and the Middle East, but as noted previously, shipping costs comprise only a small portion of the full delivery cost of exporting LNG. As these regions have infrastructure in place, as well as lower capital and liquefaction costs than Canada, Canada does not have an overall cost advantage with respect to LNG supply.

Canada's larger advantages, as noted above, are with respect to geopolitical stability and social and environmental performance. Geopolitical stability is a key determinant of supply stability as social and political conflicts may interrupt production and delivery of natural gas exports. Examples of instabilities among other potential natural gas suppliers to Europe include the Russian conflict with Ukraine, socio-political instability in Algeria and civil war in Libya (Clark 2014; Oliver and Buck 2015; Richter and Holz 2015). Canada, in contrast, has stable social and political structures that facilitate confidence in long-term supply stability.

Canada's social and environmental practices also align with European expectations for resource development. Although there are domestic concerns about the development of shale gas resources in Eastern Canada, and the construction of natural gas transportation and LNG export infrastructure across the country, it is notable that governments in Canada are acknowledging these concerns and responding through appropriate regulatory channels. However, this also lengthens the regulatory process for approval. In addition, the recent changes to environmental assessments in Canada to consider upstream greenhouse gas emissions (Government of Canada 2016), as well as recently announced changes to the operation of the NEB and the Canadian Environmental

Assessment Agency⁴³ could further limit the expansion of an LNG industry. The domestic challenges of developing natural gas reserves and export capabilities are not as pronounced in Russia, the Middle East and Africa. However, from an international perspective, these regions often engage in less than desirable social and environmental practices. A desire by European countries not to support these practices could make them a less likely supply source.

Canadian LNG export facilities therefore have a strong political and social advantage over natural gas exports from competing non-North American suppliers to Europe. These advantages could rationalize the cost premium on Canadian LNG exports in comparison to pipeline or LNG exports from Russia, the Middle East or Africa. Canada's challenge in securing a share of Europe's natural gas market therefore boils down to two distinct components. First, and most significant, Canada does not have any East Coast LNG export terminals that have reached a positive final investment decision. Second, LNG exports from the U.S. offer the same political and social advantages as those from Canada, but at lower cost. With two U.S. export facilities already operating and sending shipments to Europe, and an additional four facilities under construction, U.S. suppliers have a significant head start in securing long-term European supply contracts. Additionally, as a result of costs already incurred, these suppliers will have a stronger incentive to secure supply agreements for any uncontracted capacity and may be willing to enter into contracts at below variable operating costs. Canadian facilities, in contrast, will only be able to justify final investment decisions if they can secure contracts that allow the facilities to recover both their capital and operating costs. This competitive disadvantage further deteriorates the outlook for proposed Canadian facilities.

Potential Target Customers for Canadian LNG

Utilities that are seeking to diversify natural gas supplies constitute the majority of current European demand for North American LNG. For example, Cheniere Energy has entered into supply contracts with Gas Natural Fenosa (Spain's largest integrated gas and electricity company), Endesa S.A. (Spain's largest electric utility company), Iberdrola (Spanish-based multinational electric utility company), Électricité de France (French-based multinational electric utility company) and EDP Energias de Portugal S.A. (Portugal-based integrated utility company) (Cheniere Energy 2016a, 2016b, 2016c).⁴⁴

While these contracts show interest in diversification by large GDP economies, they also represent only a small share of total natural gas demand. For example, the sales agreement between Électricité de France and Cheniere is for approximately 5.8 BCM of natural gas to be delivered in 2017 and 2018 or an average of 2.9 BCM of natural gas per year (World Maritime News 2015). In comparison, the electricity and heat generation sector in Europe consumed nearly 165 BCM of natural gas in 2014 (IEA 2016c). The relatively small size of U.S. contracts is in part attributable to many European natural gas distributors maintaining long-term natural gas supply agreements with Russia.⁴⁵ This limits the extent to which they may diversify or substitute more significantly toward North American sources of natural gas. In addition, North American export facilities are limited in

⁴³ Bill C-69, *An Act to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other Acts*, proposed substantial changes to federal energy regulation, including creation of a new Canadian Energy Regulator and changes to impact assessments of energy projects (Bankes 2018; Mascher 2018; Olszynski 2018).

⁴⁴ A number of these companies also have operations in non-European countries, including Mexico and in South America, suggesting that not all of the LNG in their supply contracts will be sent to Europe.

⁴⁵ For example, the French multinational electric utility company Engie has signed a 23-year contract to import LNG from Russia's second largest natural gas producer, Novatek. Russia's largest natural gas producer, Gazprom, met with Eni, a major oil and gas company in Italy, in 2016 and they jointly pledged to maximize the sales of natural gas within existing long-term contracts. Other OECD Europe countries maintain long-term supply contracts with Russia. The cumulative total of these contracts is in excess of 100 BCM per year through to 2030 (Dickel et al. 2014; Reuters 2015; Sputnik 2016).

their capacity. As a result, in high-demand regions of Europe – primarily the large GDP economies – North American LNG supply can only act as an incremental source. Existing LNG contracts for Europe suggest the opportunity for Canada (and the still-proposed U.S. projects) starts opening in 2021 but is most promising post-2025 (Figure 15).

The other constraint that Canadian LNG exporters face when identifying target European customers is LNG import infrastructure. The largest European importers of LNG are currently Spain, Turkey, the United Kingdom, France and Italy. With the exception of Turkey, these are stable and developed economies where consumption of natural gas has been declining in recent years. Their ability - and desire - to absorb significant additional supplies of natural gas will be propped up by declining indigenous European production. However, it will also be limited by slow economic growth and cheaper natural gas options available from Russia, Africa and the Middle East. Turkey has the fastest rate of natural gas demand growth in all of Europe. However, as the only European country with pipeline access to natural gas from Azerbaijan and Iran – where production of natural gas is increasing – it is less likely to look toward Canadian LNG as a supply source.

Offering some potential as customers for Canadian LNG are the low wealth countries located in Central and Eastern Europe. These countries tend to have smaller economies that are growing faster than the more stable high wealth countries. They also tend to be significantly more reliant on Russia as a single natural gas supply source. Given the history of Russian supply disruptions and continuing geopolitical uncertainties, these countries therefore have a stronger motivation to identify alternative suppliers. The relatively small scale of natural gas demand in these economies may also align well with Canada's limited export availability of natural gas in the medium term.

The challenge in accessing these markets will be LNG infrastructure. Lithuania and Poland have recently started operating LNG import facilities but much of their demand is likely to be secured by LNG export facilities that are currently in operation or under construction, and which have a stronger motivation to offer more competitive pricing. New LNG import facilities have been proposed for countries bordering the Baltic, Adriatic and Black seas. These facilities could offer a better opportunity as potential markets for Canadian LNG in the medium term as construction, and the start of operations, will likely align with the timeframe for the start-up of Canada's proposed export facilities. However, as is the case in Canada, none of these import facilities is currently under construction and it is uncertain how many, if any, will move ahead.

Canada's potential customer base in Europe will also be largely influenced by the rate of adoption of renewable energy. The cost of producing electricity from renewable sources, particularly wind and solar, is dropping rapidly and approaching the cost of power generation by fossil fuels and nuclear reactors. Analysis by Bloomberg from 2015 has even found that wind power – without government subsidies – is now the cheapest form of electricity to produce in both Germany and the United Kingdom (Randall 2015).

The European Commission's current target is to increase the share of renewable energy to 20 per cent by 2020 and to 27 per cent by 2030 (European Commission 2011, 2017b, 2017c). Renewable energy proportions in 2014, as a share of total primary energy supply, were four per cent in the high wealth-large GDP countries (eight countries total, six EU), 18 per cent in the high wealth-small GDP countries (six countries total, five EU), six per cent in the low wealth-large GDP countries (10 countries total, eight EU) and five per cent in the low wealth-small GDP countries (14 countries total, nine EU) (IEA 2016c). This is far below the European Commission's target and suggests there will need to be significant adoption of renewable energy sources across all of Europe between now and 2020. As a low-emissions source, the adoption of renewable energy will also contribute to the European Commission's goal of achieving a 20 per cent reduction in greenhouse gas emissions by 2020. As shown by the IEA forecast for natural gas demand in Europe, introducing new policies to

achieve renewable energy and greenhouse gas emissions targets could slow the anticipated growth in European natural gas demand. This in turn could diminish the customer base in Europe for Canadian LNG.

5. CONCLUSIONS AND POLICY CONSIDERATIONS

While Europe is a source of incremental, rather than significant demand growth, the recent build-out in regasification capacity suggests European countries are interested in optionality and flexibility in their natural gas supply sources. This creates the potential for Canadian LNG exports, but it is not a guaranteed opportunity. Canada is but one player in a large, globally competitive market, and faces numerous challenges.

First, as a slow entrant to the LNG industry, Canadian project proponents are losing market share to faster moving jurisdictions, such as the U.S. Just as the U.S. is a major competitor for domestic markets, it is also a competitor for global LNG exports. The slower moving nature of Canadian projects, combined with the current LNG supply glut, means that the near-term window of opportunity has closed, as evidenced by the Canaport project being placed on hold.

Second, the business case for proposed projects in Quebec or Atlantic Canada is less compelling than (brownfield and greenfield) projects on the U.S. Gulf Coast. While closer to demand centres in Europe, the proposed Canadian projects require new infrastructure, unlike those in the Gulf Coast that have the advantage of significant infrastructure investments and a pre-existing petrochemical hub. Third, the lack of existing infrastructure exacerbates the fact that Canadian projects do not currently have secure natural gas supplies.

The supply question is not trivial to answer. While the Quebec projects will likely rely on natural gas shipped from Western Canada, the resistance to oil pipelines and fossil fuels in general in Quebec and across Canada may translate into resistance to the necessary pipeline infrastructure and perhaps the facilities themselves. In Atlantic Canada, the situation is even more complex. Current production is expected to decline, and imports from shale gas fields in the U.S. will require substantial build-out of additional pipeline capacity. The current moratoriums on hydraulic fracturing in Nova Scotia and New Brunswick offer little hope (as yet) for onshore development being the source of supply. Furthermore, should the governments of Nova Scotia, New Brunswick or Newfoundland and Labrador elect to lift the moratoriums, additional policy and regulatory measures will have to be implemented, as recommended by the provinces' commissions on hydraulic fracturing. This means that even if decisions were made today, the likelihood of either province having major production increases is low for the short term.

Lessons can also be taken from the B.C. experience. In particular, the length of time required to secure regulatory permits has frustrated some potential buyers and led to a major project receiving a negative final investment decision (CBC News 2016; Pacific NorthWest LNG 2017). This has repercussions for all Canadian projects, and undermines confidence in the ability of the projects to move beyond the planning stage. The federal government has committed to restoring Canadians' confidence and trust in energy regulators and environmental assessments; it should bear in mind that maintaining investor confidence in an efficient, effective and timely process is also important. The experiences with recent oil pipeline proposals suggest both may be lacking, which is detrimental to all energy investment in Canada.

Our analysis suggests Canada is at a competitive disadvantage relative to other LNG suppliers, as a higher cost and slower moving jurisdiction. However, Canada's reliability and stringent environmental and regulatory oversight may align with European countries' desire for geopolitically stable and environmentally responsible natural gas supplies, as well as an

overarching desire for diversity in sources of supply. The window of opportunity for supplying Europe starts in approximately 2021, but it is unlikely that eastern Canadian projects will be well positioned to enter the European market until 2025.

Project cancellations in B.C. have underscored the changing circumstances in the global LNG market impacting Canadian projects. The Canaport facility, arguably the best positioned in Canada to supply Europe due to its lower capital costs, has cancelled the proposed conversion due to lack of investor interest. Goldboro LNG, however, has indicated it will make a final investment decision in 2018 (Withers 2018). The outlook for Canadian projects, while not exactly grim, is certainly not rosy. Securing long-term contracts with buyers is necessary to attract financial capital to build the liquefaction facilities and associated pipeline infrastructure. And the long-term contracts depend on each project's ability to demonstrate security of supply and commitment to move quickly.

APPENDIX A: UNITS AND CONVERSION RATES

Conversion Rates for Volume and Combustion Units

		To:						
		Billion cubic metres of natural gas (BCM)	Billion cubic feet of natural gas (BCF)	Million tonnes of oil equivalent (MTOE)	Million tonnes of LNG (MT)	Trillion British thermal units (TBTu)	Gigawatt Hour (GWh)	Terajoule (TJ)
From:	Billion cubic metres of natural gas (BCM)	1.0	35.3147	0.8281	0.7353	32.8632	9,631	38,525
	Billion cubic feet of natural gas (BCF)	0.0283	1.0	0.0234	0.0208	0.9306	273	1,091
	Million tonnes of oil equivalent (MTOE)	1.2075	42.6434	1.0	0.8879	39.6832	11,630	41,868
	Million tonnes of LNG	1.36	48.0279	1.1263	1.0	49.6939	13,099	52,394
	Trillion British thermal units (Btu)	0.0304	1.0746	0.0252	0.0224	1.0	293.1	1,055
	Gigawatt Hour (GWh)	0.000104	0.003667	0.000086	0.000076	0.003412	1.0	3.6
	Terajoule (TJ)	0.0000260	0.000917	0.000024	0.000019	0.000948	0.2778	1.0

Source: Author calculations and International Energy Agency (2015, 2018).

Note: Multiply by cell value to go from row unit to column unit. For example to convert from BCM of natural gas to million tonnes of LNG, multiply by 0.7353. Conversions from a natural gas volume measurement (BCM, BCF and MT) to an energy measurement (MTOE, TBTu, GWh and TJ) are for net calorific values. Gross calorific values per volume of natural gas will differ depending on location. We use 38,525 TJ per BCM as our base value, as this was the average gross calorific value of Canadian natural gas as reported in the International Energy Agency's Natural Gas Information 2015 (IEA 2015). Following the Natural Gas Information 2015 report we use a factor of 0.9 to convert from gross to net calorific values.

Conversion Rates for Rate Units

		To:		
		Million metric tonnes per annum	Billion cubic feet per day	Billion cubic metres per day
From:	Million metric tonnes per annum	1.0	0.1316	0.0037
	Billion cubic feet per day	7.592	1.0	0.0283
	Billion cubic metres per day	268,3824	35.3147	1.0

Sources: Author calculations.

APPENDIX B: EUROPEAN PIPELINE INFRASTRUCTURE

Europe has an extensive interconnected pipeline system. Major pipelines connect producing regions – the North Sea, Russia, and Africa and the Middle East – to the subcontinent and its many transmission networks.

The North Sea

The North Sea has an extensive natural gas pipeline network that connects offshore gas fields with the primary producing countries of Norway, the United Kingdom and the Netherlands. A number of additional high wealth-large GDP countries in Western Europe – including Belgium, Denmark and Germany – also have pipeline connections to either offshore natural gas production sites or major natural gas receipt points in Norway and the United Kingdom. These pipelines are the primary conduit for internal natural gas trade between high wealth-large GDP countries.

Russia

Five primary pipelines transport natural gas from Russia to Europe. All of the pipelines are at least partially owned by Gazprom, Russia's largest natural gas company. The Soyuz and Brotherhood pipelines run through Ukraine before entering Western Europe and supplying countries throughout the western continent via the transmission pipeline network (U.S. EIA 2016b). The Soyuz also connects to the TransBalkan pipeline in Eastern Ukraine that branches off to the south and provides natural gas supply to the Balkan countries and Turkey (U.S. EIA 2014b).

Over the past two decades Gazprom has invested in three additional pipelines that provide supply to Europe via routes that bypass Ukraine. Exiting northern Russia is the Yamal-Europe pipeline which runs through Belarus, Poland and Germany (Gazprom 2017d), as well as Nord Stream 1, a twin pipeline system that runs from northern Russia to northern Germany via the Baltic Sea (Gazprom 2017b). Exiting southern Russia is the Blue Stream pipeline which runs to Turkey via the Black Sea (Gazprom 2017a).

North Africa and the Middle East

Europe's remaining pipeline supplies of natural gas are delivered from North Africa and the Middle East. Three of these pipelines – Pedro Duran Farrell, Medgaz and the TransMed (Enrico Mattei) – source natural gas at the Hassi R'Mel Hub in Algeria and connect to hubs in Spain and Italy (U.S. EIA 2016a). The remaining pipelines are the Greenstream pipeline which runs from Libya to Malta (U.S. EIA 2015a), the Tabriz-Ankara that runs from Iran to Turkey (Jalilvand 2013), and the South Caucasus that runs from Azerbaijan to Turkey (BP 2017a).

Proposed Projects

Five major European pipeline projects are under development, three of which are planned for southeast Europe. Two of the projects in southeast Europe are currently under construction. The first is the Southern Gas Corridor, a network of three pipelines that will extend from Azerbaijan to Turkey, Greece, Albania and Italy (BP 2017b). The second is the Turkish Stream pipeline, which is being constructed to the west of the existing Blue Stream pipeline, running from Russia to Turkey and Greece via the Black Sea (Gazprom 2017c). The last proposal for southeast Europe is the Eastring pipeline, a bi-directional pipeline that will run through Slovakia, Hungary and Romania and connect to Turkey via the existing TransBalkan pipeline (U.S. EIA 2015b).

In southern Europe, the proposed GALSI pipeline would transport natural gas from the Hassi R'Mel Hub in Algeria to Italy (U.S. EIA 2016a). Last, the Nord Stream 2 is the only major proposed pipeline project for northern Europe. It is a second twin pipeline system that would run largely alongside the current Nord Stream pipelines and provide additional capacity between Russia and Germany (Nord Stream 2 2017).

APPENDIX C: PROPOSED EASTERN CANADIAN LNG PROJECTS

Three LNG projects in Nova Scotia, one project in New Brunswick and two in Quebec have received export licences for LNG. This appendix provides additional detail on the projects and their proposed supply sources.

TABLE 5 PROPOSED LNG EXPORT FACILITIES IN EASTERN CANADA

Location	Asset Name	Ownership	Capacity (MTPA)	Expansion	NEB Maximum Export Allowance (MTPA)	Proposed Start Year	Capital Cost
Goldboro, NS	Goldboro LNG	Pieridae Energy Canada	10		12.3	2022	\$8.3 B (CAD)
Melford, NS	A C LNG Inc	Hiranandani Group	4.5	9	15.7	2023	\$3 B (USD) (Phase 1)
Richmond County, NS	Bear Head LNG	Liquefied Natural Gas Limited	8	4	14.3	48 months after construction start	\$9 B (CAD)
Saint John, NB	Canaport LNG	Repsol (75%), Irving Oil (25%)	5		6.0	TBD*	\$2 - \$4 B (CAD)
Port of Grand Anse, QC	Énergie Saguenay	GNL Quebec Inc.	11		13.6	2024	\$7.2 B (USD)
Becancour, QC	Stolt LNGaz Inc.	Stolt-Nielsen Gas Limited; SunLNG Holding Limited; LNGaz Inc.	0.5	0.5	0.6	2018	\$600 M USD (\$800 M CAD)

Note: The Canaport application to the NEB for an export licence suggested commissioning could begin by 2020; however, the project was put on hold in March 2016.

Sources:

1. Goldboro LNG
NEB Letter Decision for export licence: National Energy Board (2015b)
Proposed start year: Goldboro LNG (2018)
Capital Cost: Goldboro LNG (2013a)
2. A C LNG:
NEB Letter Decision for export licence: National Energy Board (2015f)
Ownership and proposed start year: H-Energy (2017)
Capital Cost: Carr (2014)
3. Bear Head:
NEB Letter Decision for export licence: National Energy Board (2015a)
Proposed start year: LNG Limited (2018b)
Capital Cost: SNC Lavalin (2015)
4. Canaport:
NEB Letter Decision for export licence: National Energy Board (2015d).
Project Cancellation and Capital Cost: Jones (2016)
5. GNL/Énergie Saguenay:
NEB Letter Decision for export licence: National Energy Board (2015c)
Proposed start year and capital cost: Énergie Saguenay (2018b)
6. Stolt LNGaz Inc
NEB Letter decision for export licence: National Energy Board (2015e)
Proposed start year and capital cost: Stolt LNGaz (2015b)

TABLE 6 REGULATORY PROCESS FOR PROPOSED LNG EXPORT FACILITIES

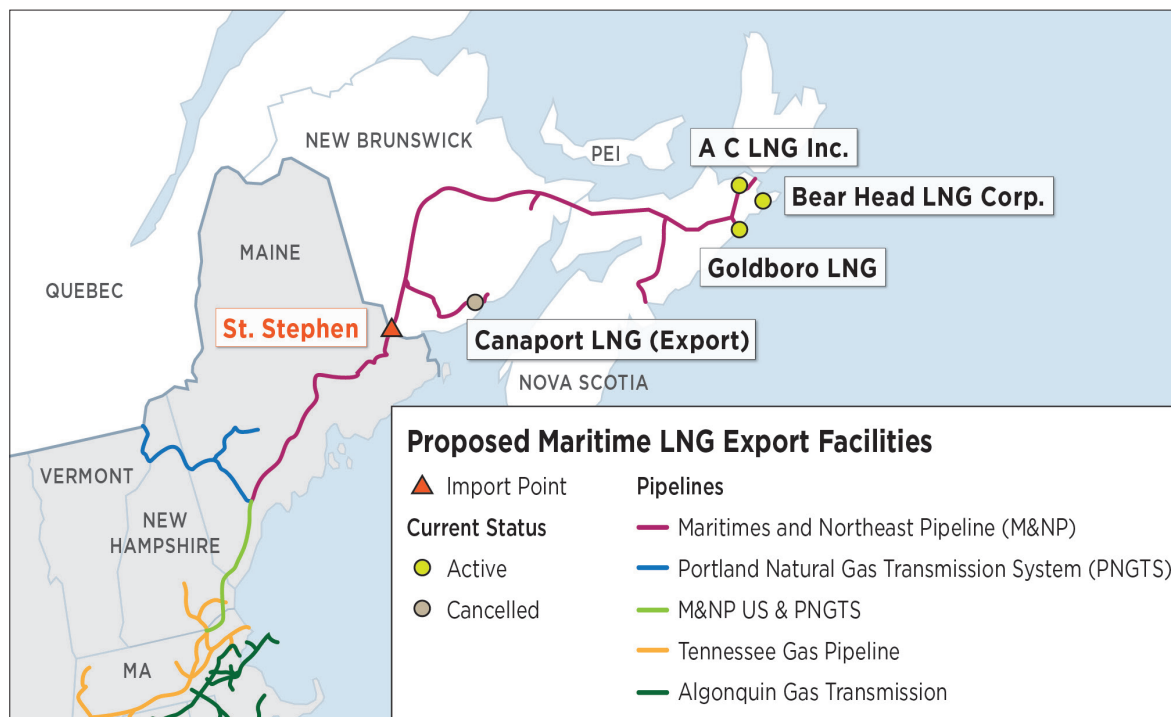
Location	Asset Name	NEB Export Licence	Provincial Environmental Assessment Office	Canadian Environmental Assessment Agency	FERC/DOE Export Licence
Goldboro, NS	Goldboro LNG	Licence Received	Approved with conditions	Waived	Received for free-trade and non-free-trade countries
Melford, NS	A C LNG Inc	Licence Received	Not yet commenced	Not yet commenced	Not yet commenced
Richmond County, NS	Bear Head LNG	Licence Received	Approved with conditions	Waived	Received for free-trade and non-free-trade countries
Saint John, NB	Canaport LNG	Licence Received	N/A	N/A	N/A
Port of Grand Anse, QC	Énergie Saguenay	Licence Received	Ongoing	Ongoing	Not required
Becancour, QC	Stolt LNGaz Inc.	Licence Received	Approved	N/A	Not required

Sources:

1. NEB export licences: National Energy Board (2018)
2. Goldboro Provincial Environmental Assessment: Government of Nova Scotia (2017c)
3. Goldboro Canadian Environmental Assessment: Goldboro LNG (2013b)
4. Goldboro FERC/DOE Export Licence: Goldboro LNG (2016)
5. Bear Head Provincial Environmental Assessment: Government of Nova Scotia (2017a)
6. Bear Head Canadian Environmental Assessment: Smith (2015)
7. Bear Head FERC/DOE Export Licence: LNG Limited (2016b)
8. Énergie Saguenay Provincial and Federal Environmental Assessment: Énergie Saguenay (2018a)
9. Stolt LNGaz Provincial Environmental Assessment: Stolt LNGaz (2015b)

Atlantic Canada

This graphic shows the four proposed LNG projects in New Brunswick and Nova Scotia and the current pipeline systems.



Source: Adapted from National Energy Board (2015h).

Goldboro LNG

The Goldboro LNG project, owned by Pieridae Energy (Canada) Ltd., is a two-train facility, with a cumulative liquefaction capacity of 10 MTPA. The application details that the first train would be operational in the 2019-2020 timeframe, with the second train operational six months later (Dawson 2014). However, the Goldboro LNG website now lists the start-up year as 2022 (Goldboro LNG 2018). The project received import and export licences from the NEB in May 2016. The project also has U.S. Department of Energy authorization to export U.S.-produced natural gas to countries with which the U.S. has free trade agreements, as well as non-free-trade agreement countries (Goldboro LNG 2016).

In May 2017 Pieridae issued a news release announcing that 50 per cent of Goldboro's initial capacity had been sold to Uniper SE, Germany's largest utility (Goldboro LNG 2017b). Ten days later, it subsequently announced a proposed merger with Pétrolia, a publicly traded junior oil and gas exploration company in Quebec (Goldboro LNG 2017a). The Quebec Superior Court approved the merger in October 2017 (Pieridae Energy 2017). By way of the merger, Pieridae will become a publicly traded company and will be positioned to use equity markets to raise funds for Goldboro LNG. It is aiming to raise \$1 to \$3 billion through this process (Risdon 2017).

The proposed gas feedstock for the project is from onshore and offshore production in the Canadian Maritimes as well as the northeast U.S. through the M&NP system (Dawson 2014). Maritimes natural gas production in 2016 was 1.8 BCM, and is expected to decline, necessitating additional supply sources (NEB 2017a). Goldboro has the advantage of being connected via pipeline to Encana's Deep Panuke offshore field; however, the project has been moved to winter production only and the reserve estimates have been downgraded (Encana 2018; NEB 2015g). The natural gas wells at the project site are forecast to be plugged in the 2019-2021 timeframe (Willick 2017). Nova Scotia's second offshore field, Sable Island, is also starting to wind down, with a full removal of offshore facilities expected to be completed by 2020 (The Chronicle Herald 2017). Future production in Quebec, from reserves currently under lease to Pétrolia, may offer Goldboro LNG an alternative domestic supply source in the long run (2025 and beyond) (Risdon 2017).

Pieridae intends to import up to 10.3 BCM per year (the equivalent of 7.6 MTPA or 28.3 MCM per day) of natural gas through the M&NP system (Dawson 2014). The current capacity of the Canadian portion of the M&NP system is 16.0 MCM per day, requiring expansion of the system in order to service domestic demand in the Maritimes as well as the multiple proposed LNG projects (NEB 2015h). Direct access to natural gas produced in the U.S. northeast additionally requires completion of the Atlantic Bridge project, which provides south to north transmission over the entire pipeline. The initial stages of the Atlantic Bridge project were brought into service in late 2017; however, pipeline owner Enbridge explicitly states the project will not be used to transport natural gas for export as LNG (Enbridge 2017d; Enbridge 2018).

Bear Head LNG

Bear Head LNG (a subsidiary of Liquefied Natural Gas Limited) was initially developed as an LNG import and regasification project, with construction commencing in 2005 and put on hold in 2007 (LNG Limited 2018b). The current proposal is for an 8.0 MTPA export facility with start-up in 2022 at earliest, and an expansion of up to 12 MTPA (LNG Limited 2018a, 2018b). Bear Head received export and import licences from the NEB in May 2016. The project also has U.S. Department of Energy authorization to export U.S.-produced natural gas to countries with which the U.S. has free trade agreements, as well as non-free-trade agreement countries (LNG Limited 2016b).

Bear Head's export licence application details source gas will come from "offshore Canadian resources such as the Scotian shelf or ... other Canadian supply regions such as the Western Canadian Sedimentary Basin" (Bear Head LNG 2014). Bear Head also intends to seek feed gas from the United States, and applied for an import licence for up to 14.2 BCM per year of natural gas (the equivalent of 10.4 MTPA or 38.9 MCM per day) (Bear Head LNG 2014). The transportation infrastructure to support the LNG facility is use of the M&NP system (which, as with Goldboro, will depend on expansion of the entire system), and construction of a lateral line from the existing pipeline to the export plant (Bear Head LNG 2014). Bear Paw Pipeline Corporation was founded to deal with permitting and commercial efforts for the lateral pipeline (LNG Limited 2016a). The Bear Paw pipeline project was approved by Nova Scotia's Ministry of the Environment in December 2016 (Government of Nova Scotia 2017b).

Canaport

The Canaport LNG terminal is an existing regasification facility with an annual import capacity of 18.0 MCM per day (7.6 MTPA) (Canaport LNG 2018). Saint John LNG Development Company Ltd., a wholly owned subsidiary of Repsol, applied for an import and export licence in February 2015 (Saint John LNG Development Company Ltd 2015). The application asked for an import licence from the U.S. for up to 7.7 BCM per year of natural gas (the equivalent of 5.7 MTPA or 21.1 MCM per day) and an export licence of five MTPA. The licences were approved in September 2015 and issued in May 2016, two months after Saint John LNG announced development of the project was being placed on hold.

The import and export licence application to the NEB states the project is "evaluating the prospect of sourcing feed gas supply from the United States and/or Western Canada" (Saint John LNG Development Company Ltd 2015). In the case of western Canadian feed gas, the routing suggested for the gas is via the TransCanada Mainline and the Trans-Quebec & Maritimes Pipeline to an interconnect with the Portland Natural Gas Transmission system (PNGTS), where it enters New Hampshire at East Hereford. The gas would then be transported along PNGTS and the M&NP, re-entering Canada at St. Stephen, New Brunswick. The gas would be transported to the Canaport facility on the Emera Brunswick pipeline. In the case of U.S. feed gas, the gas is expected to be sourced from Appalachia via the Tennessee Gas pipeline or the Algonquin Gas Transmission system, then be transported on the M&NP, and finally along the Emera Brunswick pipeline

Currently, the Emera Brunswick pipeline transports regasified natural gas from the Canaport LNG terminal to an interconnection with the M&NP near St. Stephen, New Brunswick (Emera New Brunswick 2018). The pipeline is supplied exclusively by the Canaport LNG facility, and has a 25-year firm service agreement (Emera New Brunswick 2018). This exclusive arrangement would undoubtedly make it easier to reverse the Emera Brunswick pipeline, and the pipeline would not have to be expanded. An expansion of the northern portion of the M&NP, however, would still be required.

The relative attractiveness of western Canadian versus U.S.-sourced feed gas would depend on the costs of production and the relative tolls. However, as noted for the Goldboro and Bear Head projects, supply of U.S. feed gas will depend on the expansion of the M&NP system. There is also a branch of the M&NP system that goes through Saint John, the site of the Canaport facility. This pipeline's flow could also be used to supply gas for export from Canaport LNG (Maritimes and Northeast Pipeline 2018).

A C LNG

A C LNG is a proposed 13.5 MTPA project near Middle Melford, Nova Scotia. In the NEB application (filed in May 2015), the proposed project is described as being developed in three phases. The first is a 3.0 MTPA floating LNG facility in the Strait of Canso, with commissioning in 2019. Phase two is a second floating LNG train with export capacity of 3.0 MTPA with commissioning in 2021, and phase three is an onshore facility with capacity of 7.5 MTPA, operational in 2025. However, as of fall 2017 the A C LNG project website states that the project will be a three-train, 13.5 MTPA project (4.5 MTPA per train) with a target of the fourth quarter of 2023 for commercial operations (H-Energy 2018).

The project received import and export licences from the NEB in May 2016. The import licence was approved for up to 23.8 BCM per year of natural gas (the equivalent of 17.5 MTPA or 65.2 MCM per day) The application notes the project “will likely be dependent on the ability to reverse the M&NP” and that “the major challenge for supplying gas to the Project will be adequate pipeline capacity from various sources into Nova Scotia” (A C LNG Inc. 2015). It additionally identifies pipeline expansions totalling 75.9 MCM per day that have been proposed to support expanded production in the Marcellus shale play and improve natural gas supply to Canada and New England. However, none of these expansions are on the northern portion of the M&NP, meaning that they cannot directly supply the project. Despite numerous references to obtaining natural gas supplies from the U.S., as of fall 2017 A C LNG has not commenced the necessary approvals process to receive authorization from the U.S. Department of Energy for export of U.S.-produced natural gas.

Énergie Saguenay

Énergie Saguenay is a proposed 11 MTPA export facility located at the Port of Saguenay (also known as the Port of Grande-Anse) in La Baie, Quebec (GNL Quebec Inc. 2014a). The project filed its NEB export licence application in October 2014 and received its licence in May 2016. The application describes the project as having two or three trains, with the first export cargoes predicted for September 2020, and an additional train or trains added in sequence every six months (GNL Quebec Inc. 2014b). The project website now states the facility will be in operation in 2024 (Énergie Saguenay 2018b). Feed gas for the project will be sourced from Western Canada, with the project supplied by a new 650-km pipeline that connects with the Eastern Triangle section of the TransCanada Mainline (GNL Quebec Inc. 2014b). A formal application for this pipeline, however, has not been filed as of spring 2018. GNL Quebec, the project proponent, additionally notes in its application an intent for the project to connect to numerous natural gas hubs throughout Canada’s existing natural gas pipeline network. To this extent, the application notes the project may also rely on pipeline infrastructure that moves western Canadian natural gas to Ontario through the U.S., such as the Northern Border, Great Lakes Transmission and Alliance pipelines (GNL Quebec Inc. 2014b).

Stolt LNGaz Inc.

Located at the Becancour Industrial Park, Stolt LNGaz Inc. is a small-scale liquefaction facility, designed to supply off-grid natural gas industrial customers in Eastern Canada as well as international export markets (Stolt LNGaz Inc. 2015a). The initial capacity of the project will be one train with a production capacity of 0.5 MTPA, with the option of expansion to one MTPA (Stolt LNGaz Inc. 2015a). Approximately 50 per cent of liquefaction capacity at full build-out is earmarked for export (Stolt LNGaz Inc. 2015a). The Becancour Industrial Park is connected to Gaz Metro distribution pipelines, which in turn are connected to the Trans-Quebec and Maritimes

Pipeline. These connections allow Stolt LNGaz to source feed gas from the Dawn Hub, through which it is connected to the majority of North American natural gas supply sources. The only additional infrastructure that may be required is a potential pipeline expansion to feed the facility. The application notes the facility would require approximately 2.2 MCM of feed gas per day to meet export volumes (0.5 MTPA) at full build-out; this same amount would also be required to meet domestic volumes (Stolt LNGaz Inc. 2015c). As the natural gas pipeline in the industrial park currently has excess capacity of 1.44 MCM per day, it will require an expansion to carry these additional volumes (Société du parc industriel et portuaire de Bécancour 2018).

The NEB issued an export licence for Stolt LNGaz Inc. in May 2016. As of spring 2018 the timeline on the project website continued to show construction starting in summer 2015 (Stolt LNGaz 2018). News articles from winter 2016, however, suggest an FID had been postponed until summer 2016 (Rochette 2016). There has been no evidence since that time of an FID having been made.

Gas Pipeline Expansions

The most significant challenge facing proposed East Coast Canadian LNG facilities is the identification of sources of supply, and gaining access to this supply via adequate pipeline capacity. This is of particular concern in Nova Scotia where the M&NP – the only pipeline that brings natural gas into the region – is cited by all projects as a primary source of supply. Current capacity of the M&NP, however, is sufficient to serve only 11 per cent of the projected capacity of Nova Scotia's three LNG projects. As described below, there are a number of proposed pipeline projects that will allow additional natural gas volumes to reach the southern portion of the M&NP. This is a promising first step for Nova Scotia's proposed export facilities. Gaining access to this supply, however, will require either an accompanying expansion on the M&NP or a new pipeline that runs from the northeastern United States to eastern Nova Scotia.

- Atlantic Bridge Project by Enbridge: The Atlantic Bridge project is a joint project involving Enbridge's Algonquin Gas Transmission (AGT) and the M&NP. The AGT starts in New Jersey and carries natural gas from the Marcellus shale to customers in New England. It interconnects with the M&NP at Dracut, Massachusetts. The Atlantic Bridge project includes a small expansion of capacity (+3.8 MCM per day) on the AGT and reversal of the southern portion of the M&NP (Spectra Energy Partners 2015). This will result in the M&NP being bi-directional over its entire system and therefore able to carry Marcellus gas to customers in New Hampshire, Maine and the Maritimes. Notably, however, the project will not result in an expansion of capacity on the M&NP. The project received FERC approval in January 2017 and was originally anticipated to be operational in November 2017. Enbridge filed a request with FERC in October 2017 to bring certain components of the project in-service on November 1 (Enbridge 2017b). Other components have encountered local opposition and remain under construction.
- Algonquin Incremental Market ("AIM") by Enbridge: AIM is an expansion of the AGT from Ramapo, New York to city gates in Connecticut, Rhode Island and Massachusetts. The project was completed in January 2017 and resulted in an additional 9.7 MCM per day of capacity on the pipeline (Enbridge 2017a).
- Access Northeast by Enbridge, Eversource Energy and National Grid: The Access Northeast project is an extensive upgrade and expansion of the AGT that would add 26.8 MCM per day of capacity. Spectra Energy (now Enbridge) initiated the pre-filing review process for the project in November 2015. However, Enbridge withdrew the project from pre-filing in June 2017, citing a lack of consistent energy policies across the New England states. Enbridge indicated a continued commitment to the project from itself and its partners (Eversource

Energy and National Grid) and an intent to re-engage in the pre-filing review process once greater policy alignment is achieved (Enbridge 2017c).

- **Continent-to-Coast (C2C Expansion) by Portland Natural Gas Transmission System:** The northern portion of the PNGTS runs from the U.S./Canadian border at Pittsburgh, New Hampshire, where it interconnects with the Trans-Quebec and Maritimes (TQM) pipeline, to Westbrook, Maine where it interconnects with the M&NP. The C2C expansion project is a request to increase the certified capacity on this portion of the pipeline from 4.75 to 5.95 MCM per day. The application additionally seeks authorization to increase PNGTS' authorized import and export volumes from 5.04 to 5.95 MCM per day. The increase in capacity does not require any construction or modification to the existing pipeline and will be enabled by an increase in delivery pressure from the TQM. PNGTS submitted its application for the increased capacity in December 2016 (TransCanada 2016). It received all of its approvals in November 2017 and started operating on December 1, 2017 (TransCanada 2017).

APPENDIX D: CAPITAL COST OF PROPOSED U.S. LIQUEFACTION FACILITIES

United States

Location	Name	Trains	MTPA	Capital Cost (\$USD)	Status
Georgia	Southern LNG Company	N/A	2.5	\$1.9 billion	Under construction
Louisiana	Cheniere Sabine Pass LNG	T1-4	18.0	\$12.5 to \$13.5 billion (T1-5)	Operating
		T5	4.5		Under construction
		T6	4.5	N/A	Waiting FID
Louisiana	Magnolia LNG	T1-4	8.0	\$4.354 billion*	Waiting FID
Louisiana	Sempra Cameron LNG	T1-3	13.9	\$7 billion	Under construction
		T4-5	10.0	N/A	Waiting FID
Louisiana	Southern Union Lake Charles LNG	T1-3	16.8	\$8.6 billion	Waiting FID
Maryland	Dominion Cove Point LNG	N/A	5.3	\$4.0 billion	Operating
Texas	Cheniere Corpus Christi LNG	T1-2	9.0	\$9.0 - \$10.0 billion	Under construction
		T3	4.5	N/A	Under construction
		T4-5	9.0	N/A	Pending Application
Texas	Exxon Mobil Golden Pass LNG	T1-3	15.6	\$10.0 billion	Waiting FID
Texas	Freeport LNG	T1-3	13.9	\$14.0 billion	Under construction
		T4	5.0	N/A	Pending application

*The Magnolia LNG cost estimate is for the engineering, procurement and construction contract only. It does not include owner costs.

Sources:

1. Southern LNG Company: Kinder Morgan (2017)
2. Cheniere Sabine Pass LNG: Cheniere Energy (2017b)
3. Magnolia LNG: LNG Limited (2018c)
4. Sempra Cameron LNG: Sempra-Energy (2017)
5. Southern Union Lake Charles LNG: Energy Transfer (2015)
6. Dominion Cove Point LNG: Dominion Energy (2017b)
7. Cheniere Corpus Christi LNG: Cheniere Energy (2017b)
8. Exxon Mobil Golden Pass LNG: Golden Pass Products (2017)
9. Freeport LNG: Freeport LNG (2018a, 2018b).

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G. Kent Fellows (PhD, Calgary) is a Research Associate at The School of Public Policy, University of Calgary. Dr. Fellows has previously worked as a researcher for the University of Alberta's School of Public Health and as an intern at the National Energy Board. He has published articles on the effects of price regulation and bargaining power on the Canadian pipeline and pharmaceutical industries as well as the integration of renewable generation capacity in the Alberta electricity market. He has also provided expert testimony to the Senate of Canada on the topic of transportation economics as it relates to national trade corridors and participated in the Alberta Government's Energy Diversification Advisory Committee Natural Gas and Crude Oil expert working group sessions. Kent is also involved in forwarding The School of Public Policy's Canadian Northern Corridor research program, which is aimed at studying the concept of a multi-modal linear infrastructure right of way through Canada's North and near North.

Dexter Lam is passionate about helping organizations develop capabilities to grow and thrive sustainably. He blends design approaches with integrative strategy to define unique opportunities for value-creation and human-centered impact. Dexter has worked with leading strategy and innovation practices such as Doblin, Monitor Deloitte, and J5 to help corporate, public-sector and social-venture organizations succeed in the face of uncertainty.

Paul Craig is a strategist focusing on the Energy Sector. Mr. Craig has held strategy positions with Energy companies and Consulting firms in North America and Europe. He was previously the Canadian Oil and Gas Sector Specialist for a global Consulting firm. He has advised global Energy companies, First Nations, and Provincial Governments on the LNG market, ecosystem, regulatory policy and economics of LNG facilities.

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