LNG in Canada: value chain, project structure and risk allocation

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ABSTRACT

LNG in Canada stands at an important inflection point. On the one hand, the next few years could witness affirmative final investment decisions by a strong number of the proponents of Canadian LNG projects and Canada could become an important player on the global LNG stage. On the other hand, regulatory and cost uncertainty, coupled with unfavourable market conditions and economics, could combine to put a chill on Canada’s nascent LNG industry, stunting all or most projects.

Given the significance of this crossroads, this article examines the history and modern characteristics of the LNG industry to illuminate the context in which Canadian LNG final investment decisions, whether positive or negative, are being made. In particular, this article examines the different project structures or ‘economic models’ LNG projects may adopt, as well how these models can impact the value chain and myriad of related contractual arrangements that coalesce to transport natural gas from upstream reservoirs across oceans to downstream consumers. Attention also shifts regularly to the specifics of the Canadian stage in the hope of drawing insightful comparisons and contrasts between the budding Canadian LNG industry and its international counterparts.

For those interested in learning more about the Canadian LNG industry or the international LNG industry in general, this article serves as a comprehensive, albeit high-level, introduction from a Canadian perspective. For those with LNG experience in other jurisdictions, this article serves as a refresher complimented with considerations endemic to Canada’s LNG industry. What will hopefully also be apparent to both groups of readers is that proponents of Canadian LNG projects are navigating diverse sets of circumstances the responses to which are often proving as instructive as they are interesting.

1. INTRODUCTION

Liquefied natural gas (LNG) in Canada stands at an important inflection point. On the one hand, the next few years could witness affirmative final investment decisions by a strong number of the proponents of Canadian LNG projects and Canada could become an important player on the global LNG stage.1 On the

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1 As of the time of writing in July 2015, only a single Canadian LNG project has made a final investment decision. This was announced by the Petronas-led Pacific NorthWest LNG project in June 2015 but, importantly, was made conditional on the ratification of the project’s Project Development Agreement with the Province of British Columbia (BC) and a positive regulatory decision on the project’s
other hand, regulatory and cost uncertainty, coupled with unfavourable market conditions and economics, could combine to put a chill on Canada’s nascent LNG industry, stunting all or most projects.

Given the significance of this crossroads, this article examines the history and modern characteristics of the LNG industry to illuminate the context in which Canadian LNG final investment decisions, whether positive or negative, are being made. In particular, this article examines the different project structures or ‘economic models’ LNG projects may adopt, as well how these models can impact the value chain and myriad of related contractual arrangements that coalesce to transport natural gas from upstream reservoirs across oceans to downstream consumers. Attention also shifts regularly to the specifics of the Canadian stage in the hope of drawing insightful comparisons and contrasts between the budding Canadian LNG industry and its international counterparts.

No two LNG projects are the same, and this has never been more the case than it is today. Appreciation of the different structures a LNG project may take, and the legal consequences that result from these decisions, is therefore of prime importance to all LNG project participants, both current and prospective. Towards this end, this article examines LNG project structures and value chains in three parts. First, we take a brief look at the history of the international LNG industry and LNG trade growth, as well as Canada’s positioning amongst such trade flows. We next take a survey of the various different participants in LNG projects and the LNG value chain while, also paying attention to some of the hallmarks or particularities of the LNG value chain in the Canadian context. Finally, we turn to consideration of the different LNG project structures or ‘economic models’ project participants may employ, as well as the result of such decisions on risk allocation. An examination of project structure, risk allocation and risk mitigation in the Canadian context is then conducted.

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2. THE GROWTH OF THE INTERNATIONAL LNG INDUSTRY AND LNG TRADE

Global LNG trade and LNG sales and purchase agreements

At its heart, the LNG industry was born out of the drive to connect stranded natural gas resources with insufficient local markets to distant natural gas consumers suffering from a shortage of local natural gas supplies.ENVIRONMENTAL ASSESSMENT BY CANADA’S FEDERAL GOVERNMENT. BC PASSED LEGISLATION ALLOWING IT TO ENTER INTO PROJECT DEVELOPMENT AGREEMENTS WITH LNG PROJECT PROPHETS WAS PASSED ON 21 JULY 2015. 2 ‘There is no best or preferred manner for structuring a LNG project. Rather, the structure of each project will be determined on an individual basis reflective of the particular characteristics of the project. Each project participant will have a unique risk profile and will require a project structure which offers the best protection to its interests.’ Joanna Kay and Peter Roberts, ‘Structuring LNG projects – evolution or revolution in the LNG supply value chain?’ in Paul Griffin (ed), Liquefied Natural Gas: The Law and Business of LNG (2nd edn, Globe Law and Business 2012) 13, 19.

3 As noted by Kay and Roberts, ‘[t]he past 40 years have seen much change in the LNG industry, leading some commentators to question whether the projects of today bear any resemblance to the traditional project structures of the past.’ ibid 13.

4 As noted by Paul Griffin, ‘[p]ut simply, it is difficult to see where the law and business of LNG are now (and will be in the future) without first seeing where they have come from’. Paul Griffin, ‘Introduction’ in Paul Griffin (ed), Liquefied Natural Gas: The Law and Business of LNG (2nd edn, Globe Law and Business 2012) 5, 5. For a comprehensive review of the history of the LNG industry focusing on seminal projects that did much to shape the industry’s development, see Philip R Weems and Harry W Sullivan, Jr., ‘LNG at 50 – History and Projected Future for Liquefied Natural Gas Exports in an Unconventional Era’ (2014) 60 Rocky Mt Min L Inst 6-1.

5 As articulated by Weems and Hwang, the ‘LNG industry is important simply because known reserves of natural gas are often not located near potential customers’; Philip R Weems and Monica Hwang, ‘Overview of Issues Common to Structuring, Negotiating and Documenting LNG Projects’ (2013) 6(4) JWelB 267, 277.
It is a simple premise, but one that in practice has proven to contain the potential for great complexity, and in this regard Canadian LNG projects stand primed to join the international LNG industry at a dynamic point in its evolution.\textsuperscript{6} Simply put, international LNG development and trade looks quite different today than it did at its origin approximately 50 years ago, and there is every indication that the LNG industry will only continue to diversify in the decades to come.

It is also important to appreciate the particular junction Canadian LNG export projects would inhabit within broader international LNG trade patterns and supply and demand dynamics. Global LNG trade amounted to 241.1 million tonnes (MT) in 2014.\textsuperscript{7} Such trade originated from global LNG export terminals with an aggregate liquefaction capacity of approximately 301 MT per annum (MTPA) and was transported to receiving terminals totalling 724 MTPA in regasification capacity.\textsuperscript{8} As of early 2015, a total of approximately 293 MTPA of liquefaction capacity has been proposed for Western Canada\textsuperscript{9} and a further 51.5 MTPA for Eastern Canada.\textsuperscript{10} International LNG consumption is not limitless, and significant Canadian LNG liquefaction capacity will only come to fruition where mutually beneficial commercial offtake arrangements within the context of international market conditions and long-term projections can be reached.

Towards this end, the fundamental place of LNG sales and purchase agreements (SPAs) within LNG project development also requires emphasis. It is natural for energy lawyers to approach assessment of a LNG project and its value chain starting with upstream production and ending with downstream consumption. This thinking chronologically follows the natural gas from its first production through to pipeline transportation, liquefaction, marine transportation, regasification, pipeline transportation and ultimate consumption. Note, however, that in some circumstances the opposite approach may be more appropriate.\textsuperscript{11}

The large capital investment generally necessary to underwrite a LNG project means that they are fundamentally demand driven and that absent sufficient long-term purchase commitments—often for at least 80 per cent of a project’s initial output capacity for its first 20–25 years of operation—most LNG projects simply will not be built.\textsuperscript{12} Natural gas is not oil, and their storage, transportation and markets function very differently with the result that there is no immediate international market for natural gas as there is for oil.\textsuperscript{13} In addition, given that the LNG value chain is fundamentally interlinked, its constituent parts can only be thought of in isolation to a limited degree: in many ways each will inform the others and be negotiated and drafted in consideration of the others.

Importantly, this means that changes in course taken in respect of downstream arrangements, including, in particular, LNG SPAs, may require corresponding re-navigation of upstream arrangements.\textsuperscript{14} This highlights the importance of keeping intended LNG sales arrangements in mind from the genesis of a LNG project’s planning, appreciating, of course, practical limits on foresight as well as the possibility of related market

\begin{itemize}
\item \textsuperscript{6} Michelle Michot Foss and others, ‘LNG Supply, Trade and Contracting Patterns: Is Transformation Happening?’ (AIPN 2012) 63–65; Griffin (n 4) 5–12; Kay and Roberts (n 2) 27–28.
\item \textsuperscript{8} ibid.
\item \textsuperscript{9} ibid 31.
\item \textsuperscript{10} ibid 32.
\item \textsuperscript{11} As put by Kay and Roberts, while LNG project proponents ‘are often tempted to focus most interest on the development and financing of the infrastructure . . . the primary focus should be on the metrics of the regasified LNG consumption market, since it is the essential revenue generator without which the LNG project would be unsustainable’; Kay and Roberts (n 2) 19–20.
\item \textsuperscript{12} See Weems and Hwang (n 5) 280. This can be contrast with petroleum development where, even in respect of the largest capital expenditure projects (eg offshore and oil sands), the existence of the downstream market can be comfortably relied on (commodity price projections, of course, being another matter).
\item \textsuperscript{13} See Peter Roberts, Gas and LNG Sales and Transportation Agreements – Principles and Practice (4th edn, Sweet & Maxwell 2014) 8, 49–50 and 61.
\item \textsuperscript{14} Note that this ‘interlinkage’ of LNG value chain agreements continues well past execution. For example, as highlighted by Kay and Roberts, pressure felt by LNG buyers to reduce consumer prices to more competitive levels can run back up the supply chain as LNG buyers look to renegotiate price and volume amounts under long-term SPAs negotiated when gas supplies were lower; Kay and Roberts (n 2) 25.
\end{itemize}
or industry developments: indeed, it is not uncommon for a project’s LNG SPAs (or at least their term sheets) to be negotiated prior to upstream natural gas purchase agreements and related transportation or project ownership agreements.15 This also underscores the importance of appreciating the complexity and typically bespoke nature of LNG sale and purchase arrangements. Just as it is fair to say that no two LNG projects are alike, so too is it fair to say that no ‘fit for all purposes’ model LNG sale and purchase agreement exists: while each will likely contain a ‘common group of core issues’, significant variance on a number of material issues can be anticipated.16

Atlantic basin LNG trade

In the wake of the discovery of massive gas fields in North Africa, the UK and France became the world’s first regular importers of LNG in the mid-1960s, striking offtake arrangements with Algeria and Libya. International LNG trade in the Atlantic basin expanded further in the 1970s when the USA also began importing LNG from North Africa, although LNG trade to the US always remained a fraction of that to Western Europe.

Atlantic basin LNG trading begun to grow much more rapidly in the late 1990s after steady (but relatively slow) growth through its first two and a half decades. The immediate post-millennium years saw a stampede of new LNG project proposals in the USA, and by the time the manoeuvring had wound down five new import terminals and expansions to three of the four original US terminals had been commissioned.

Feeding this growth spurt was a perception of declining domestic US natural gas production coupled with large anticipated natural gas demand growth in other sizeable Atlantic basin economies, including Mexico and Brazil. Significant discrete events also played a part, perhaps most notably the turbulence of California’s electricity market restructuring in 2000–2001, which unexpectedly sent natural gas spot prices soaring, particularly through the warmer summer months.

LNG trade in the Atlantic basin has continued to evolve quickly ever since. Atlantic basin LNG importers welcomed among their ranks Puerto Rico in 2000, the Dominican Republic in 2003, Argentina in 2008 and Brazil and Canada in 2009.17 In addition to Algeria and Libya, Atlantic basin LNG exporters now include, among others, Norway, Nigeria, Trinidad and Tobago, Angola and Equatorial Guinea. Spain is an important player among Atlantic basin importers, benefitting from favourable geography that gives it ready access to African, Middle East, North Sea and Caribbean exporters and the ability to engage in LNG re-export where circumstances dictate.18 Declines in North Sea natural gas production has led to increased LNG import capacity in the UK. Similarly, a growing desire to diversify past reliance on Russian natural pipeline imports has also led a number of continental European nations to increase LNG import capacity.

In terms of trade volumes, the United Kingdom and Spain were Europe’s largest LNG importers in 2014, receiving 8.5 MMTA (or approximately 3.5 per cent of global demand) and 8.2 MMTA (or approximately 3.4 per cent of global demand), respectively.19 The next two largest Atlantic basin importers in 2014 were Mexico and Brazil, receiving 6.9 MTPA (or approximately 2.9 per cent of global demand) and 5.7 MTPA (or approximately 2.4 per cent of global demand), respectively.20 The largest LNG exporters in the Atlantic basin in 2014 were Nigeria, exporting 19.5 MTPA (or approximately 8.1 per cent of global supply), Trinidad and

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16 ibid 29.
17 See the discussion of the Canaport LNG facility in New Brunswick, Canada, later in the Section ‘Canadian projects within international LNG trade’. Note also that the site of the proposed Kitimat LNG export project in North West BC was initially planned as the site for a LNG import facility intended to help satisfy growing power demand in Alberta’s oilsands industry.
18 See IGU (n 7) 9–10. LNG ‘re-loads’ have at times pushed Spain to the position of Europe’s largest exporter of LNG, even though it produces none domestically.
19 ibid 14.
20 ibid.
Tobago, exporting 14.4 MTPA (or approximately 6 per cent of global supply), and Algeria, exporting 12.8 MTPA (or approximately 5.3 per cent of global supply).21 That said, the Atlantic basin remains the world’s smallest LNG import market, representing only approximately 23.6 per cent of global demand in 2014. The Atlantic basin is also increasingly presenting a tale of three contrasting import regions, namely Europe, North America and Latin America. Europe has seen dropping LNG demand over the past several years, a reduction largely accredited to stagnant economic growth coupled with increased reliance on coal and alternative powers sources for the generation of electricity.22 The significant growth of shale gas production in the USA has also seen LNG importation into North America, including both Canada and Mexico, drop significantly over the past decade.23 Latin America, on the other hand, including in particular Brazil and Argentina, has been having the opposite experience, with the former requiring increased LNG imports to offset regular deficiencies in hydropower production and the latter looking to offset continued declines in domestic natural gas production.24 The end result has been a redirection of LNG many volumes originally intended for Europe and North America to Latin America, with Latin American LNG imports surpassing North American imports for the first time in 2012 and almost doubling them by 2014.25

**Pacific basin LNG trade**

In contrast to the Atlantic basin, LNG trade in the Pacific basin expanded swiftly in the 1980s and 1990s. Japan was the first major player among Asian LNG importers, beginning LNG imports from Alaska in 1969 and adding LNG imports from Indonesia, Brunei and Abu Dhabi over the course of the 1970s. Following closely behind were South Korea and Taiwan, who quickly ramped-up sizeable regasification and import capacity in conjunction with LNG export projects developed in Southeast Asia, Australia and the Middle East.

China and India constitute the latest significant entrants to Pacific basin LNG trade, the former experiencing natural gas consumption growth of 382 per cent between 1999 and 2010 and the latter experiencing natural gas consumption growth of just over 200 per cent over the same period.26 Lesser known importers in the Pacific basin include Chile and Thailand. Other significant Pacific basin LNG exporters include Malaysia and, most recently, Russia (with its Sakhalin project going online in 2009). In total, Pacific basin LNG trade has for some time dwarfed that of Atlantic basin LNG trade, with Japan, South Korea, China, India and Taiwan being the five largest LNG importers globally in 2014.27

In terms of import trade volumes, Japan has historically been—and continues to be—the world’s dominant LNG importer, accounting for approximately 36.9 per cent of global imports (or 88.9 MTPA) in 2014.28 South Korea and Taiwan represent approximately 21.4 per cent of world LNG demand, importing 38 MTPA and 13.6 MTPA in 2014, respectively.29 China and India, on the other hand, imported 20 MTPA and 12.9 MTPA in 2014, respectively, to collectively represent approximately 14.4 per cent of world LNG imports.30 China and India are also expected to be amongst the largest continued LNG import growth markets going
forward, with the former country recently committing to expanding import and regasification capacity from
approximately 19 MTPA to approximately 47 MTPA.

In terms of export trade volumes, Pacific basin producers supplied approximately 31 per cent of the
world’s LNG production in 2014.31 This places the Pacific basin behind the Middle East as the largest LNG
exporting region, which in 2014 supplied approximately 41 per cent of the world’s supply.32 However, a num-
ber of large LNG projects under development in Australia have that country set to significantly increase its
total export capacity, and in so doing leapfrog Qatar as the world’s largest exporter nation in 2017 as well as
propel the Pacific basin into the world’s largest exporting region ahead of the Middle East.33 In particular, as
of early 2014, Australia had 7 LNG projects under construction with an aggregate liquefaction capacity of
61.8 MTPA—a staggering 53 per cent of total global LNG liquefaction capacity under construction—with
Papua New Guinea, Malaysia and Indonesia collectively contributing a further 15.2 MTPA under construc-
tion.34 In terms of current, non-Australian LNG supply in the Pacific basin, as of 2013 Malaysia exported
25.1 MTPA (or approximately 10.4 per cent of global supply), Indonesia exported 16 MTPA (or approxi-
mately 6.6 per cent of global supply), Russia exported 10.6 MTPA (or approximately 4.4 per cent of global
supply) and Brunei exported 6.2 MTPA (or approximately 2.6 per cent of global supply).35

Middle East LNG exporters
The third chief LNG trade sphere is the Middle East, a ‘pivotal’ LNG export region with the ability to pour
LNG into both the Pacific and Atlantic basins.36

Abu Dhabi was the first Middle East exporter in 1977, and stood alone in this regard until the 1990s when
Qatar began a concerted build-up of LNG capacity. This campaign in 2010 lifted Qatar to its current position
as the single largest LNG exporter globally with an aggregate liquefaction capacity of 77 MTPA (equal to ap-
proximately 31.9 per cent of global demand). Qatar is also notable for its dedication of approximately a third
of its export capacity to short-term and mid-term LNG sales and purchase arrangements and spot transac-
tions as well as its significant participation in arbitrage opportunities between regional markets.37

Oman is also recognized as somewhat of an originator in the short-term LNG sales and spot market arena,
including by becoming in early 2008 the first Middle East exporter to re-direct LNG cargoes originally sched-
uled for Europe to higher price Asian import markets.38 As of 2014 its LNG exports stood at 7.9 MTPA (or approxi-
mately 3.3 per cent of global supply), with nearby Yemen’s LNG exports at 6.8 MTPA (or approximately
2.8 per cent of global supply) and the United Arab Emirates LNG exports at 5.8 MTPA (or approximately
2.4 per cent of global supply).39 Dubai, for its part, has envisioned itself as a potential LNG trading
hub, in part based on the strength of its financial sector.40

Iran is another Middle East natural gas producer with significant remaining reserves, but it has to this
point been unable to join the international LNG industry following years of political isolation and associated
trade and investment sanctions. Political complications to the further development of the LNG industry in
the Middle East are not limited to Iran, however, with a number of different political tensions handicapping

31 ibid 7.
32 ibid.
33 IGU (n 23) 9, 17.
34 ibid at 17. Papua New Guinea LNG export capacity saw start-up in 2014.
35 IGU (n 7) 14.
36 Foss and others (n 6) 28.
37 ibid at 25. Generally speaking, short term trades are those made under agreements for two or less years (including single cargo trades),
and medium term contracts are those for lengths of 2–5 years.
38 ibid 26.
39 IGU (n 7) 14.
40 Foss and others (n 6) 26.
the progress of intra-regional trade. For example, while the ‘Dolphin’ pipeline project has provided for the transportation of Qatari gas to the UAE and Oman, Kuwait has been unable to negotiate a similar arrangement with Iraq with the result that the country began receiving LNG shipments from Australia in 2009.

Although not part of the Middle East, East Africa stands to become another potentially important swing supplier of LNG into the Atlantic and Pacific Basins in a fashion similar to Middle East LNG exporters. The past few years have witnessed natural gas discoveries offshore Mozambique and Tanzania sizeable enough to support plans for liquefaction terminals of as much as 35 MTPA, with the recognized potential for expansion capacity to as much as 85 MTPA. That said, enthusiasm over these plays has been tempered by appreciation of the significant project risks such jurisdictions present due to lack of local infrastructure and resources, evolving domestic natural gas demand requirements and potential political instability, among others.

In total, while the Pacific basin historically served as the world’s largest exporting region, a surge in liquefaction capacity in the Middle East over the past two decades led to this mantle being passed westward. As discussed, however, due to significant liquefaction capacity scheduled to come online in Australia and other regional exporters over the next half decade, the Pacific basin will soon again hold this title. The full consequences may be significant both for the Middle East and internationally. The growth in Middle East LNG export trade since the 1990s resulted in a significant re-shuffling of international LNG trade flows, marked in particular by the growth of Middle East to Pacific trade based on the flexibility of Europe-bound LNG SPAs and arbitrage opportunities between European and Pacific markets. As noted by the International Gas Union, substantial new Pacific basin supply is set to bring an end to the post-Fukushima status quo of tight supply, leaving Asia and Asia Pacific ‘well-supplied’ for the first time in a number of years, which, ‘combined with downward pressure on LNG prices, may put an end to the growth of Middle East-Pacific and Atlantic-Pacific trade seen in recent years’ as more Atlantic and Middle Eastern supplies are pushed into Atlantic and Mediterranean markets.

Canadian projects within international LNG trade

The LNG industry is inherently international in nature. Some domestic LNG markets have begun to develop in recent years, but the vast majority of LNG trade and development remains international in scope. So too are international LNG shipping costs, including within and between exporting and importing basins, a major determinant of LNG trade flows and pricing dynamics. As a result, understanding Canada’s geographic placement within the broader global LNG industry is a prerequisite to appreciating the opportunities, challenges and competitors Canadian LNG projects face.

In this regard, perhaps the predominant geographic characteristic of Canadian LNG is its situation between, and ready potential access to, both the Pacific and Atlantic basins. As noted by a recent study published for the AIPN, in addition to representing LNG’s principal consumption centres, the Atlantic and Pacific basins also happen to be ‘very different in terms of evolution and receiving market characteristics’.

Unlike the Pacific basin, the Atlantic basin is generally characterized by the well developed and competitive nature of its LNG importers’ natural gas markets. This is particularly the case in North America, which saw Canada and the US liberalize and deregulate their natural gas markets in the 1980s. The United Kingdom, with the ‘National Balancing Point’ or ‘NBP’ and supportive domestic policy, is approaching a...
similar level of market integration/competition. Continental Europe, although still patchy, has also made notable forward progress in this regard. Such competitiveness is made possible by the fact that North America and Europe benefit from significant local natural gas production as well as significant regional natural gas pipeline transportation infrastructure including, in the case of North-western Europe, from the North Sea and, in the case of Continental and Eastern Europe, from Russia and North African producers.

By contrast, given their lack of domestic natural gas production and significant geographic obstacles to pipeline importation infrastructure, a major ‘hallmark’ of the Pacific basin’s historic three largest LNG importers—Japan, South Korea and Taiwan—is their ‘almost total dependence on imported oil and LNG to meet energy demand’ and corresponding lack of robust competitive domestic natural gas markets. As a consequence, in terms of LNG pricing regimes, Pacific basin importers have historically been willing to pay a premium for LNG supplies in the drive to address energy security risks not similarly tolerated by their Atlantic basin counterparts. Pacific basin LNG trade is also characterized by significantly greater participation by state-owned enterprises (SOEs) as importers—who may view participation in the LNG industry more as a national policy objective than as a purely commercial enterprise—than is Atlantic basin trade. Moreover, while Pacific basin LNG trade is significantly larger in total volume than Atlantic basin trade—at approximately double the amount—it is more concentrated in the number of both exporting countries and importing countries. Other significant differences between LNG trade to the Atlantic and Pacific basins include common pricing regimes (ie crude oil linked, index linked or hybrid), common price review policies, practices and mechanisms, and common approaches to destination restriction or destination flexibility, divergences some commentators argue have only been widening in recent years.

It is also important not to consider Canadian LNG export potential with too narrow a view or undue emphasis on Pacific basin trade and consumption to the exclusion of Atlantic basin and Middle East LNG activity. It is true that the great majority of proposed Canadian LNG export capacity is planned for the country’s western shores in British Columbia (BC), and that the large importing nations of northeast Asia represent the natural export markets for such liquefaction terminals. However, as a globally integrated industry, developments in other export jurisdictions, key trade routes and trade spheres can and will have an effect on the viability, and ultimate long-term success, of Canadian LNG export projects. For example, the direct impact of US LNG export projects situated along the Gulf of Mexico in Texas and Louisiana that reach an affirmative final investment decision (FID) and enter service will in good part be felt in the Atlantic basin, ie in the form of LNG exports to European and South American import markets. However, to the extent that US LNG

48 ibid 17–18.
49 ibid.
50 ibid 21–22.
51 ibid 22.
52 See Roberts (n 13) 62.
53 Foss and others (n 6) 20.
54 As noted by Roberts, ‘[t]he price of LNG in a long-term SPA has traditionally reflected the energy economics of the market into which that LNG is being sold’, with the result that LNG sold to Northeast Asia has typically been tied to the local price of crude oil and its products while LNG sold to Europe has typically been tied to competing natural gas and crude prices alongside linkage to various energy indices; see Roberts (n 13) 63–64. For more detailed discussion regarding the history of LNG pricing into Northeast Asian markets, see Howard V Rogers and Jonathan Stern, ‘Challenges to JCC Pricing in Asian LNG Markets’ (Oxford Institute for Energy Studies, 2014).
55 Price review clauses have been less common historically in LNG SPAs signed with Asian buyers than in SPAs signed with European buyers. See Rogers and Stern (n 54) 1, 36–37. See also Roberts (n 13) 77–86.
56 Destination-flexible LNG SPAs remain more common in the Atlantic basin and from the Middle East than in the Pacific basin, and towards this end an important consideration is the impact of applicable competition law. Simply put, in certain jurisdictions (eg the EU) restrictions on destination flexibility are deemed anti-competitive and therefore prohibited. See Roberts (n 13) 47–60. Note also that diversion clauses and destination restriction/flexibility clauses can be amongst the most heavily negotiated clauses in a LNG SPA. See Farmer and Sullivan (n 15) 50–51.
projects supply Atlantic basin consumption, the greater the ability of, and motivation for, Middle East exporters to target shipments to the Pacific basin and Canada’s potential Asian customers.

A myriad of other trade and market contingencies require deliberation. The exact terms on which US LNG exports will compete with BC LNG in the Pacific basin actually remains an open question. The expansion of the Panama Canal, expected to be completed in third quarter of 2015 at the time of writing, will enable approximately 80 per cent of the current global LNG fleet to pass from the Atlantic to the Pacific and vice-versa, compared to only approximately 7 per cent of the fleet prior to the expansion.58 Although questions persist regarding cost and congestion,59 the larger corridor can only increase the competitiveness of US projects in the Pacific basin to the detriment of Western Canadian projects. One of a number of other question marks hanging over the head of the long-term prospects of West Coast Canadian LNG projects is the degree to which the future exploitation of Asian unconventional gas reserves (including, in particular, in China) could decrease the appetite of Canada’s cross-ocean customers for internationally sourced energy.60 So too does the future nuclear energy policy of Japan, as well as the ultimate success of a recently executed significant and long-term natural gas export deal between Russia and China, represent material determinants of long-term Canadian LNG prospects. On the other hand, continued growth in Latin American LNG consumption could prove a benefactor of Canadian LNG considering, among other things, the well suited pairing of Latin American LNG consumption with offtake from the merchant and third party tolling model LNG projects that characterize the US LNG landscape.61

Nor should the possibility of Canadian East coast projects be quickly dismissed. The strong and steady growth of USA shale gas production in the Marcellus and Utica formations in that country’s Northeast and Midwest is resulting in an abundance of natural gas supply available for export. The Canaport LNG facility, commissioned in New Brunswick, Atlantic Canada, in 2009, was designed and constructed as a LNG import terminal to feed power generation in the populous New England region of the US through the import of LNG from North Africa and other Atlantic basin LNG producers. However, as the growth in regional production has undercut the need for imported feed gas, a number of different plans to export US shale gas production from Canada’s East Coast have been proposed, including the reversal of certain Canadian and US pipelines and the conversion of the Canaport facility to an export terminal, as has been proposed by Repsol in its export licence application in February 2015.62 East Coast Canadian LNG export projects also stand to directly benefit from the growing desire by European countries to diversify natural gas import sources away from Russia mentioned earlier. Similarly, it is interesting to note that shipping costs from Canada’s East Coast to India are less than from both the US Gulf Coast and Canada’s West Coast. Finally, as will be discussed further in the sub-Section ‘LNG Project Structure and Risk Allocation and Mitigation in Canada’, Canada’s East Coast presents opportunities for merchant or tolling model LNG projects different than available in BC.

In total, the prospect of Canadian LNG was initially introduced by Canadian Government and industry as a lucrative secondary market to be exploited: as recently as 2013 LNG was loudly touted in BC as a gold mine of future government revenue capable of feeding massive generational income funds. However, in light

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59 ibid.
60 ibid.
of continued near-exponential growth in US shale gas production, the projected long-term sustained growth of such production and corresponding decreases in Canadian natural gas exports to US markets, Canadian LNG is increasingly being viewed as an opportunity that needs to be harnessed merely to sustain business as usual for Western Canadian natural gas producers, markets and industry. This is focusing the energy of both Canadian government and industry, but also opening many eyes previously accustomed to only considering continental supply and demand fundamentals to the intricacies of international LNG market dynamics and time horizons.

3. LNG PROJECT PARTICIPANTS AND THE LNG VALUE CHAIN

The evolution of LNG project participation

The momentous growth of the international LNG industry over the past five decades has been fuelled by a number of different factors, including but not limited to steadily increasing energy demand in Asia, market disruptions and supply concerns, and the increasing reliance by utilities on natural gas over competitor feedstocks. Importantly, however, the growth of the international LNG industry during this time has been matched by increased diversification in the scope and nature of players participating in the LNG value chain.

At its inception, the LNG value chain was characterized principally by the involvement of, on the upstream side, large multinational integrated energy companies and/or national oil companies producing LNG for export and, on the downstream side, large public utilities acquiring LNG for consumption as a fuel stock for power generation. Host governments also often played a prominent role, both at jurisdiction of export and jurisdiction of import, dictating many of the material terms of a project’s structure as well as the conditions of participation by private third parties.

Such neat lines are no longer the norm. The LNG industry has witnessed steadily greater participation across the LNG value chain by players previously concerned with only a single component. The examples are plentiful. Downstream utilities now routinely acquire equity interests in upstream natural gas production rights and liquefaction facilities. Non-integrated upstream producers and exporters now routinely take equity interests in midstream LNG infrastructure. SOEs, historically concerned more with economic development only in their home territories, are increasingly deciding to become majority project proponents in far-flung and often unfamiliar foreign jurisdictions. Improvements in technology and reductions in certain project costs have also made possible the entrance of smaller industry players.

In addition, whereas once host government direct involvement, both on the liquefaction side as well as on the regasification side, would be a natural expectation in connection with a proposed LNG project, this has since failed to be the case. Furthermore, the decreased role or absence of direct state involvement in many new LNG projects has allowed LNG project participants greater latitude in customizing their desired project structure and value chain arrangements, a freedom often restrained where a host government designed a particular LNG project guided by nation-building policies and priorities rather than those of greater interest to private LNG participants. On the other hand, another relatively new development is that of national oil companies from exporting countries taking an equity interest in foreign receiving capacity.
Many other developments across the LNG value chain are equally noteworthy. Historically larger to take advantage of economies of scale, smaller-scale LNG liquefaction projects are becoming more common alongside smaller-scale regasification terminals.\textsuperscript{72} Such efforts are in part being facilitated by advances in floating LNG liquefaction facilities and floating storage and regasification facilities, which bring with them advantages in flexibility by allowing for redeployment in different geographic locations depending on market conditions. Perhaps most importantly, import and export players have been joined by large marketers or ‘aggregators’ whose primary business is engaging in LNG portfolio trading and who participate in LNG projects and the LNG value chain as both purchasers and vendors.\textsuperscript{73} Also of great significance has been the emergence of often significant regional LNG price differences as well as the drive by various different project participants to dedicate increasing amounts of LNG capacity to spot sales and shorter-term LNG SPAs alongside the more traditional fixed long-term arrangements.\textsuperscript{74}

**Modern LNG project participants**

How is the typical modern LNG project structured? Asking this question is much like asking the length of a piece of string: just as it will depend on the particular piece of string, so too will the optimal structure of a particular LNG project depend on its particular circumstances. These include the location of the proposed feedstock gas, the nature of the proposed downstream buyers, the degree of upstream natural gas market development, and the availability of ready-built infrastructure, whether pertaining to liquefaction, regasification or pipeline or marine transportation. Perhaps most important, however, will be the nature of the proposed project participants and their individual commercial drivers and acceptable risk exposure. As discussed, the LNG industry has become populated by an increasing number of different players, each of whom brings with them their own set of possibly conflicting business objectives to the LNG value chain.

**Natural gas producers**

At the inception of the LNG value chain are upstream natural gas producers. This may include vertically integrated, multinational energy companies or simply large, mid or small-cap producers with no desire to secure equity ownership in either midstream or downstream LNG infrastructure or operations. These may also include state-owned energy companies in addition to publically or privately held producers with no state or government entities among their controlling shareholders.

Where a producer is looking to participate merely by selling feedstock natural gas to other LNG project participants it will be interested in securing the highest possible sales price. By contrast, where equity upstream natural gas production is viewed primarily as means of securing feedstock to produce LNG for consumption by downstream affiliates this concern will be diminished, upstream operations and their attendant costs viewed more as one of several large overhead expenses rather than as a distinct profit-making enterprise. Also different will be the priorities of an entity engaging in upstream natural gas production wholly or partially as a means to secure feedstock supplies for merchant downstream LNG sales to unaffiliated third parties: for these participants the preference will likely be to keep the cost of feedstock natural gas as low as possible to increase the margins obtained on arm’s length LNG sales.

**Pipeline companies**

The extent of pipeline infrastructure necessary in connection with a LNG project can vary greatly at either end of the LNG value chain, possibly even to the degree that its role will be a relatively minor one compared to the other project components. That said, given that global regasification capacity (\textsuperscript{72}4 MTPA) currently

\textsuperscript{72} Kay and Roberts (n 3) 28.
\textsuperscript{73} See Farmer and Sullivan (n 15) 47–49.
\textsuperscript{74} See Rogers and Stern (n 54) 5–7, 45; Foss and others (n 6) 8, 52, 64; Weems and Hwang (n 5) 298.
greatly exceeds global liquefaction capacity (301.2 MTPA),\textsuperscript{75} it is generally more likely that a new LNG export project will require more significant new-build pipeline capacity at its upstream, liquefaction end than at its downstream, regasification end. Stated differently, not every proposed new LNG export project will include associated new-build downstream, regasification and transportation infrastructure. Indeed, where the project consists of a floating liquefaction facility stationed above an offshore natural gas reservoir no significant new-build pipeline transportation infrastructure may be needed at all.

Where significant new pipeline infrastructure is required, a principle question will become the optimal owner(s) and operator(s) of the new pipeline. In some cases, such as under an integrated project model or project tolling model, the project proponents may agree to take proportional ownership of the new pipeline with one of them designated as operator. Where this approach is taken (ie project ownership of the new-build pipeline), the project parties may roll development, construction and operation of the pipeline into their project development agreement(s) alongside development of the LNG facility itself. Alternatively, the new-build pipeline can be approached independently, including through the use of unbundled pipeline-specific project finance.

In other circumstances it may be deemed advisable to engage the services of a third party, non-project participant midstream services provider. This approach brings with it increased project costs in the form of the for-profit tariff that will be charged for gas transportation services. This approach also likely brings with it the need for separate pipeline project development arrangements between the project proponents and the midstream services provider alongside other project development agreements, as well as the need to ensure proper coordination of these agreements, including triggers for final investment decisions and associated conditions precedent (eg the negotiation of definitive transportation services agreements). However, these extra costs and administrative burdens may be more than offset by the special expertise and local experience and resources brought to the benefit of the project by the midstream company.

**LNG liquefaction facility operators**

LNG liquefaction facilities stand at the core of any LNG value chain for a wealth of reasons. Liquefaction facilities will typically represent the largest capital cost component of a LNG project, often costing well into the tens of billions of dollars (depending primarily on intended nameplate capacity). Prior to an affirmative final investment decision, proposed liquefaction facilities may draw the most attention from government and the public, require the greatest amount of engineering, design and analysis, attract the greatest number of regulatory hurdles, and require the greatest amount of stakeholder consultation and accommodation. Post-final investment decision, liquefaction facilities may also be that LNG project component which takes the longest time to construct and which will carry the most significant potential liability, including in the form of cost-overruns, liability to fixed-term downstream LNG buyers for delays in (or other unavailability of) commercial operations, and abandonment and reclamation liabilities.

For these and other reasons, there is no entity more central to a LNG project than that entity or project participant that will own and operate the liquefaction facility. Furthermore, no other entity or project participant will be as affected by the project structure or ‘economic model’ adopted in connection with a LNG project as will the liquefaction entity or project participant. As will be discussed in further detail below, a number of different treatments are possible. At one end of the spectrum, liquefaction can be near-seamlessly integrated into the wider LNG value chain, conducted collectively for and on behalf the larger LNG project by the project participants without even the requirement of a distinct tolling agreement to govern the operations pursuant to which feedstock natural gas is liquefied into LNG. At the other end of the spectrum, liquefaction services may be provided by a third party entity wholly unaffiliated with any other LNG project proponent and without title to either the natural gas or LNG ever passing to the facility owner.

\textsuperscript{75} IGU (n 7) 6, 19.
Additional complexities are also possible, including where different project participants will hold different equity interests in one or more individual liquefaction trains or ‘train companies’ and with certain common facilities comprising the LNG facility to be shared collectively amongst all of them. Where this is the case, complex ‘common facilities’ agreements will be required, addressing, depending on the circumstances, those terminal facilities to which all project participants will have common access/operational rights, the allocation of excess, underutilized or reduced common facilities capacity, allocation of costs associated with the common facilities, operatorship of the common facilities, including the scope of authority of any associated common facilities governance committee, and the rights and obligations of the current project participants and any future participants to expansions of the facility and common facilities.76

LNG maritime transportation companies

Although it is possible for a new LNG export project to proceed without any significant dedicated pipeline transportation capacity, this is almost by definition less the case with LNG shipping, given that LNG projects are essentially pursued to connect natural gas producers and consumers that cannot be economically connected by pipeline infrastructure. In other words, no significant LNG liquefaction project can proceed without a comparable amount of dedicated LNG maritime transportation capacity, whether in the form of specially-commissioned new-build vessels or the dedication of one or more existing vessels or fleets.

Like pipeline transportation infrastructure, LNG shipping vessels dedicated to a project can be built, owned and operated by the project proponents as project assets alongside associated liquefaction or regasification facilities, or can be built, owned and operated by specialist third party companies for charter by the LNG project or project participants on a for-profit, fee for services basis. There are also recent examples of shipping companies taking an equity interest in LNG liquefaction facilities, including through joint ventures with other value chain participants such as diversified interest holders. Unlike pipeline transportation infrastructure, LNG maritime shipping operations will be directly subject to a number of international conventions, including, not least, the International Convention on Limitation of Liability for Maritime Claims, 1976 and its associated 1996 Protocol.77 That said, applicable national legislation will continue to play a primary role where a LNG vessel is within the ‘Exclusive Economic Zone’ of a coastal state as recognized by the United Nations Convention on the Law of the Sea.78

Where the global business operations of a LNG project participant include the ownership of LNG vessels, they will be in a position to reduce operating costs in a manner similar to project equity ownership of new-build pipeline infrastructure. Other efficiencies may also be available, however. Although LNG shipping has historically been characterized by ‘tramline-trading’ patterns (ie the monotonous ‘back and forth’ movement of a project-dedicated LNG vessel on its laden voyage from the LNG export facility to a downstream regasification facility for unloading of its cargo before then immediately making the ballast (unladen) voyage back to the same liquefaction terminal),79 equity control of a larger LNG fleet can facilitate nimbler trading operations, whether engaging in spot-sales and/or meeting wider portfolio marketing delivery obligations.80 In fact, as noted by Kay and Roberts, for many industry participants, downstream energy/power market liberalization has made the ability to engage in more flexible trading arrangements a core facet of their optimization planning and/or a condition precedent to commercial viability.81

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79 Foss and others (n 6) 30.
80 See Weems and Hwang (n 5) 284.
81 Kay and Roberts (n 3) 24–25.
Flexibility in shipping arrangements has also been facilitated by the growth of independently owned, third-party fleets. In particular, whereas historically LNG tanker fleets were owned and operated by LNG buyers or sellers (or groups of LNG buyers or sellers), the last decade has witnessed the emergence of independent tanker companies as owners of approximately one third of international LNG shipping capacity. In this regard, the LNG maritime shipping industry is also noteworthy for its important niche maritime transportation operators (e.g., BW Group (previously Bergesen Worldwide) and Golar LNG) as well as for the steady increase in the cargo-carrying capacity of LNG vessels over the past 50 years. Interestingly, LNG shipping arrangements have also proved capable of attracting political intervention, including the determination of some LNG importing nations to support domestic shipbuilding industries by requiring that local LNG purchasers commission the engineering and construction of dedicated LNG vessels from domestic shipyards.

**Downstream LNG buyers**

If the LNG liquefaction facility represents the nucleus of a LNG project, downstream LNG demand may represent the most complicated facet of the LNG value chain. Downstream buyers and end-users can vary widely in nature and objective. They are also subject to a wide variety of macro and micro and internal and external factors.

Downstream LNG buyers may include utilities purchasing for their own consumption, whether at a singular power project connected to LNG regasification and natural gas storage facilities or by way of further transportation via additional on-shore transportation infrastructure. Alternatively, downstream buyers may be primarily engaged in natural gas importing and marketing operations, including sales portfolios with both industrial and retail consumers. Downstream buyers may or may not seek to take an equity interest in regasification facilities. They may seek to lock down all volumes requirements by way of fixed, long-term contracts. Alternatively, they may leave a portion of their demand volumes uncovered, to be satisfied by way of short-term spot sales. They may also engage in situation-specific break-bulk or remarketing strategies, including the use of offshore floating or onshore regasification and storage units capable of directing LNG cargoes to other domestic facilities in times of resource shortages or re-exporting LNG cargoes to foreign markets in times of domestic resource surpluses.

Downstream LNG demand is also subject to a number of potentially dynamic external factors. Depending on the degree of deregulation or liberalization, utilities may operate within competitive electricity markets or within government mandated domestic franchises. They may either be permitted to or prohibited from passing through the costs of natural gas procurement to end-users regardless of market volatility and/or the availability of lower-cost electricity generation feedstock. They may operate in a climate of government policy greatly promoting natural gas power over other power generation feedstocks. They may reside in jurisdictions with large seasonal variations in resource shortage, including large seasonal shifts in hydroelectric, solar or wind power supply. They may or may not have the benefit of domestic natural gas supplies or ready access to pipeline imports from nearby export markets. They may or may not have the benefit of local or continental

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82 See Foss and others (n 6) 36.
83 In contrast to the recent trend of wider participation across the LNG value chain by upstream producers and downstream utilities, ‘LNG shipping is increasing by being undertaken by specialist shipping companies … which are not directly connected to the LNG seller or buyer but undertake this function in the expectation of securing an economic return in their own right from the carriage of LNG under charter’; Kay and Roberts (n 3) 22.
84 See Weems and Hwang (n 5) 284.
85 See also Weems (n 57) 278–79.
86 Interestingly, in contrast to liquefaction facilities, the LNG regasification terminal ‘is often the last, and cheapest, major capital project link in the LNG supply chain’; Foss and others (n 6) 37.
competitive natural gas markets and index pricing. One or more of these circumstances may also be subject to radical transformation over the duration of a fixed, long-term LNG SPA. Downstream demand is also subject to unforeseen market disruptions, either in the immediate term (eg Fukushima) or of a more systemic nature (eg the potential for prolonged $60 oil).

This uncertain consumption environment has the effect of making downstream contractual negotiations often the most difficult, contentious and high stakes negotiations among the LNG value chain. For example, in recent years the issue of perhaps the greatest controversy has been the determination of LNG buyers in various trade spheres to shift LNG supply contracts toward pricing based on natural gas indexes (eg Henry Hub) and away from the traditional oil-linked price basis. This has also led to downstream LNG arrangements being the locus of the most significant LNG legal disputes, most notably in the form of high-value price review arbitrations.

Diversified interest holders

While we have discussed each of the above LNG project participants individually to this point, to do so can in fact be somewhat misleading. As discussed above, the evolution of the international LNG industry has seen a steady diversification of the nature of players participating in the LNG value chain with the result that upstream, midstream and downstream operations are no longer the province of closed sets of companies. Rather, it has for some time now been standard for LNG project proponents, depending on the project structure or 'economic model' adopted, to assume equity participation at multiple levels across the LNG value chain.

These include large, private integrated international oil and gas companies as well as state-owned integrated international oil and gas companies. These also increasingly include large, diversified corporate conglomerates with interests and operations in various different business sectors directly or indirectly involved in the LNG value chain, including shipbuilding, marine transportation, steelmaking and project engineering and construction. Finally, these can include industry-focused players engaging in LNG project construction and operations or LNG aggregation and portfolio sales consisting of long-term, short-term and spot LNG sales arrangements, and involving either or both sales of equity LNG as well as merchant trading.

The various possible commercial drivers and concerns of these diversified interest holders, as well as the interaction of their business objectives with those of their fellow project participants, are the most difficult to summarize. Conflicts of interest are possible on a number of different fronts. On the one hand, a diversified interest holder may encounter strain between its preferred project structure (including economic terms and/or risk allocation) and that structure preferred by its prospective project partners, necessitating negotiation and compromise if the project is to proceed with all parties participating. On the other hand, a diversified interest holder may experience strain between the best interests of two or more of its internal business units to be involved in a proposed LNG project, requiring strategic decision-making regarding whether to promote or advantage the welfare of a certain business unit over one or more other business units.

Other important players

In addition to the role played by upstream producers, transportation companies, LNG facility operators, downstream buyers and diversified interest holders, a fulsome appreciation of the often complex dynamics of LNG projects requires consideration of the influence of those various players who, although not directly involved in LNG operations, nonetheless qualify as instrumental to the successful development and operation of a LNG project. These include:

- **Project Lenders**: Project lenders (where involved) can exert tremendous influence over LNG project structure and risk allocation and will carefully scrutinize every element of the LNG value chain prior to financing.
EPC Contractors: Engineering, design and construction contractors play a crucial role at the front-end of a LNG project, including in terms of their ability to resolve project-specific design challenges and to meet construction deadlines, as well as in terms of the amount of liability they will agree to assume in connection with project completion, operational capacity and other performance standards.

Labour: Sufficient labour resources can be key to limiting LNG project costs, particularly where the possibility of labour shortages exists and considering the dependence of LNG projects on highly skilled construction labour forces.

Host Governments: Even where a host government does not seek direct involvement in a LNG project, its potential influence over the fate of a project—positive or negative—cannot be easily understated. Given the highly capital-intensive nature of LNG projects, regulatory efficiency and transparency are paramount in the design, consultation and certification process. So too is the trust of project sponsors that a particular project will not be allowed to be taken captive by local politics or rumblings akin to resource nationalism.

Local Stakeholders: Depending on the particular project, securing the support of local stakeholders can be a fundamental project condition precedent, and where this is the case should be made a principal strategic concern from the earliest stages of a project’s consideration. Note, however, that depending on a project participant’s home country and past LNG experience, the inclusion of significant consultation with such stakeholders in a project’s development may constitute an unfamiliar exercise.

Home Governments: Given the importance of energy security as a fundamental government concern, where a significant project participant is a SOE its home government can attempt to hold sway over material project decisions or project economics in a number of ways, including through targeted subsidies or preferential regulatory treatment, tax incentives, the coordination of contractual arrangements with other national enterprises or even national enterprises of other project participants.

The LNG value chain in Canada

As should be increasingly apparent, every LNG project is the sum of a unique combination of interrelated constituent parts, the exact composition and interaction of which will range from project to project depending on the project model adopted as well as the associated business operations of the project proponents. As articulated by Kay and Roberts, ‘[t]here is no single definition of the supply chain: it is whatever it needs to be in order to give the requisite definition to any particular LNG project’. Generally speaking, however, the LNG value chain will involve upstream production, transportation to a LNG liquefaction and storage facility, the offloading of the LNG onto LNG tankers for ocean transport, receiving and regasification at an import terminal, and then transportation of the natural gas to downstream end-users.

Each of these individual components can represent a substantial infrastructure project in and of itself, and each presents its own unique challenges. Bringing this chain into proper alignment therefore adds a further layer of complexity, and constitutes the primary challenge faced by legal counsel to a LNG project. In order to be successful a project must be approached as a whole to ensure the value chain functions in lockstep and is not subject to fraying or fracture. It is also important to appreciate that value chain components may have different hallmarks, or involve different legal or commercial considerations in different jurisdictions, and that this is no different in the Canadian context.

88 Griffin (n 4) 9; writing in 2012, Paul Griffin noted that ‘[t]he recent mood of resource nationalism among some producer states has not left existing LNG contracts unaffected and is likely also to affect the development of new and enduring contractual arrangements’.
89 Kay and Roberts (n 3) 15.
90 ibid 15, 26. As put by Kay and Roberts, the LNG value chain can be described as ‘a series of freestanding projects which are carried out under the umbrella of an overall project’.
91 ibid 19–20, 25–28; see also Weems and Hwang (n 5) 279–96.
Canadian LNG project participants

Unlike many other LNG export jurisdictions, Canada is entering the LNG race amid mature and robust continental natural gas industry and consumption market with extensive existing natural gas transportation and treatment infrastructure. The Canadian natural gas industry is also characterized by the longstanding participation of a full spectrum of locally based market players, from speculative junior producers financed primarily by subsequent rounds of private capital to vertically integrated majors with market capitalizations in the tens of billions of dollars. This can be contrasted with a number of other more recent entrants into the LNG space, including Papua New Guinea, Angola, Mozambique and Equatorial Guinea, which generally entered the LNG market with little or no domestic natural gas industry or transportation or processing infrastructure and which in some cases largely continue in this manner today. Even Australia and Indonesia, with their extensive LNG export history and additional projects under construction, cannot be characterized as having quite as deep and integrated a natural gas industry as does Canada.

That said, Canada’s nascent LNG industry has also attracted large first-time upstream acquisition/investment in the Canadian oil patch by significant international players with no little or previous or current Canadian operations, including large Northeast Asian utilities as well as large diversified/integrated Asian SOEs. This has the somewhat unusual result of making some Canadian LNG projects the combination of project partners with extensive existing local operations (eg land management departments, geologists, engineers and field personnel) and some project partners with only a recently relocated skeleton management team (or even no permanently transplanted local management). What may also surprise some outside observers is that, given that Calgary is home to the great majority of Canada’s oil and gas commercial, engineering, environmental and legal expertise, although principally located in Northern BC and the East Coast Maritime provinces, much of the non-physical work being done to support the development of Canada’s LNG industry is actually occurring in Southern Alberta.

The Role of Canadian government

Another key contrast between Canada and other LNG export jurisdictions is the degree and nature of government involvement. Most importantly, government authorities in Canada do not seek direct equity involvement in LNG projects. Rather, as is generally the case in most other industries in the country, Canadian authorities prefer to limit their involvement to that of regulator, which in respect of the LNG industry includes taxation authority, upstream production royalty payee, environmental regulator and infrastructure permitting authority, among other roles. This can be contrasted with those jurisdictions in which the host state requires participation in LNG export projects as an equity owner, whether directly or through a SOE, including Nigeria, Qatar, Yemen, Oman, the UAE, Trinidad and Tobago, Algeria, Libya and Malaysia, to name a few. In Abu Dhabi, for example, the host country made continued foreign participation in the ADGAS project past its initial term in 1977 conditional on the foreign participants agreeing to relinquish majority ownership to the Abu Dhabi National Oil Company. Much more complicated government participation arrangements are also possible: more recently, some host governments have exhibited interest in making access to upstream production conditional on the project sponsors agreeing to profit sharing structures with respect to revenues derived from LNG cargoes diverted from their original destination to take advantage of price arbitrage opportunities.

Key regulatory approvals to be obtained in Canada include a LNG export licence from the National Energy Board (NEB). The prime consideration of the NEB in making this determination is whether the natural gas to be exported would exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada, having regard for the trends in the discovery of oil and

92 See Foss and others (n 6) 52.
gas in Canada.\textsuperscript{93} During the earliest stages of LNG project development in Canada there was some trepidation regarding the approach the NEB would take to this analysis in the context of multiple large export permit applications within a short time period, resulting in a market expectation that earlier movers could enjoy a significant advantage over later competitors (eg that permits issued further to later applications could be rejected or made subject to various conditions precedent or qualifications).

Such fears have since been largely assuaged by the approximately 200 MTPA in LNG export volumes permitted under 12 licences issued by the NEB as of July 2015, which have generally been issued on the premise that ‘the size of Canadian natural gas resources and the integrated and well-functioning nature of the North American gas market’ are sufficient to ensure that Canadian gas requirements will be met.\textsuperscript{94} Amendments to the NEB Act have also streamlined the export permit application process: whereas the first LNG export application required the filing of detailed gas supply information alongside multiple rounds of written submissions and oral hearings, recent applications have been processed without the need for hearings and have resulted in near standardized letter decisions/export licences. Such relative regulatory certainty can be contrasted with lingering concerns regarding the availability and sanctity of US LNG export permits to ‘non-free trade agreement’ jurisdictions, which to date have stipulated that allowable export volumes may be re-examined where it is in the public interest. In total, much of the difference between Canadian and US perspectives on energy security and local supply concerns, as well as the urgency of such concerns to public interest and lobbying groups (which are more active on this point in the US), can likely be explained by the historic role of Canada as a net-energy exporter rather than a net-energy importer, a recent significant manifestation of which is the proposed extension of the maximum term of NEB export licences from 25 years to 40 years as put forth in Canada’s federal budget in April 2015.

Other regulatory regimes notable in the context of Canadian LNG include the Investment Canada Act (ICA) and environmental certification. The ICA is triggered where the acquisition of a controlling interest in a business exceeds certain monetary thresholds, attracting scrutiny by the federal government regarding whether the investment will be of a ‘net benefit’ to the country.\textsuperscript{95} Given the extent to date of foreign SOE participation in the Canadian LNG race, it is interesting to note that such investment has not attracted any of the political controversy that recently erupted in connection with majority SOE investment in Canada’s oil sands industry when the takeover by CNOOC of Nexen in early 2013 led to revisions to the ICA’s guidelines stipulating that ‘control of a Canadian oil sands business by a foreign SOE [will be a] net benefit to Canada on an exceptional basis only’.\textsuperscript{96} With respect to environmental approvals, key to appreciate in the Canadian context is that where a legislated environmental assessment process applies, a clearly defined hierarchy of legislative authority is imposed with the result that project-related permitting decisions by provincial and federal authorities cannot precede government decisions on environmental assessment (although such processes are often conducted in parallel in the interest of efficiency).\textsuperscript{97} Here it is noteworthy that the Canadian LNG industry has avoided the same degree of political opposition and activism that has dogged pipeline projects seeking greater export access for Canadian oil, including projects targeting West Coast export facilities as well as projects targeting East Coast export facilities.

Also notable is the degree to which the Canadian federal government and provincial governments such as BC have made fostering the development of a Canadian LNG industry a key priority. At the federal level, in addition to the amendments to the NEB Act streamlining approval processes and the intention to extend the

\textsuperscript{93} National Energy Board Act, RSC 1985, c N-7, s 118.
\textsuperscript{95} Investment Canada Act, RSC 1985, c E-28 (1st Supp) s 14.1(1) and (2). Given that the great majority of Canadian LNG projects are greenfield projects rather than established businesses, to the knowledge of the author no investment in a proposed Canadian LNG project has yet to trigger an ICA review.
\textsuperscript{97} Environmental Assessment Act, SBC 2002, c 43, ss 9–10; Canadian Environmental Assessment Act, SC 2012, c 19, ss 6–7.
maximum length of NEB export licences from 25 to 40 years, in February 2015 it was announced that Canadian LNG facilities would enjoy accelerated depreciable capital cost allowance treatment under Canadian tax law, allowing project proponents to deduct the cost of equipment used to liquefy natural gas at a rate of 30 per cent rather than at 8 per cent and other infrastructure at the facility at 10 per cent rather than at 6 per cent. Provincial initiatives include a corporate tax credit available to LNG income tax payers permanently established in the province and based on amounts of feedstock natural gas acquired for a local LNG facility, as well as broad government support, cooperation and participation in consultation and negotiations with First Nations groups. Indeed, in May 2015 BC joined Petronas in its offer to the Lax Kw’alaams First Nation of a $1.15 billion benefits package to win support for the Pacific NorthWest LNG project by contributing 2,200 hectares of Provincial land around Prince Rupert harbour that the Lax Kw’alaams would be able to use for industrial and residential purposes.

Upstream natural gas development and production

Historically, many of the first LNG projects involved large new or newly dedicated government concessions or production sharing contracts serving as the source of feedstock natural gas: a stranded upstream resource base would be identified by project proponents, and then a government concession, licence or production sharing contract would be issued with the specific intention of the subject reservoirs being exploited for the sole or primary purpose of supplying the proposed liquefaction facility. This practice of course also continues today, as recently evidenced in connection with, among others, the Rovuma Basin offshore northeast Mozambique and the Prelude floating LNG project offshore northwest Australia.

However, this manner of project-specific upstream development stands in rather stark contrast with LNG project development in jurisdictions like Canada and the USA, where upstream natural gas development is characterized by widely-held producing lands already subject to significant development, and in respect of which dedication to a LNG project is only one of a possible number of monetization strategies. In addition, the relatively straightforward acquisition and/or administration of a single (or small number of) specially dedicated concession(s) or licence(s) can be contrasted with the potentially significantly more complicated acquisition and/or administration of a large number of upstream licences subject to existing joint operating agreements and featuring a wide array of third party (ie non-project) working interest holders and working interest holder rights, including independent operations rights and rights of first refusal. Amongst other things, this can make participation in the upstream component of a North American LNG project a more involved undertaking than some international LNG players may anticipate or be accustomed to. This also highlights how, in contrast to several other jurisdictions internationally, Canada does not prohibit foreign ownership of upstream oil and gas production rights, even by foreign SOEs.

Consideration of upstream natural gas acquisition and administration in Canada should also take place from both a pre-FID and post-FID perspective. The acquisition of a sizeable upstream natural gas resource base may be a condition precedent to participation in a proposed LNG project, particularly in the case of an integrated project model or project tolling model. This means that a prospective project participant may be expected to secure significant upstream resources well before being eligible to make an affirmative FID election and with the result that it would be left holding such resources where the project does not proceed.

98 That said, BC also took a significant step against its own cause in announcing the implementation of the Liquefied Natural Gas Income Tax Act in October 2014. This legislation will impose a tax on the net income earned from liquefaction operations at LNG facilities located in BC a tiered basis. Beginning 1 January 2017, this income will be subject to a 3.5% tax rate. However, during that period when net operating losses and capital investment are to be deducted, a 1.5% tax rate will be applied with such taxes paid creditable against future income when the 3.5% tax rate is applicable. Beginning in 2037, the 3.5% rate will be increased to 5%.

99 For further discussion of BC’s support for LNG projects proposed in that Province, see the Section ‘LNG project structure and risk allocation and mitigation in Canada’.

100 To the surprise of some industry observers, the Lax Kw’alaams rejected the offer, although negotiations among the Lax Kw’alaams, BC and Pacific NorthWest LNG continue as of the date of writing.
whether at its election or at the election of the other project parties. Numerous further considerations arise where the upstream assets are held by the LNG project proponents collectively pursuant to a joint venture arrangement rather than independently. These include the appropriate procedure for pursuing expansion projects or the acquisition of additional dedicated resources, how natural gas will be marketed pre-FID, whether the joint venture should be allowed to pursue local demand market opportunities in respect of production beyond that necessary to satisfy project demand, how to deal with the upstream assets of one or more minority participants who vote against FID in the face of majority support for project development, and/or how to deal with the upstream assets where a majority of the project proponents vote against FID.

Addressing these issues will require complex and highly customized joint operating agreements, which in Canada will require appreciation of the historic dominance of the various generations of form operating agreements developed by the Canadian Association of Petroleum Landmen or ‘CAPL’. These will likely be unfamiliar to foreign project partners more accustomed to dealing with Association of International Petroleum Negotiators (AIPN) model joint operating agreements, as will CAPL’s various related model precedents. Towards this end, it should be highlighted that, while the 2007 version of the CAPL model operating procedure incorporated a number of improvements and expansions specifically directed at better accommodating multi-stage and multi-well horizontal operations, it is still common practice for this precedent to be heavily negotiated and customized for unconventional operations. The degree to which relevant provisions of the newly released AIPN 2014 Model Unconventional Resources Operating Agreement—also the product of industry drive to better accommodate multi-party unconventional operations in precedent agreements, including in particular in respect of operations by less than all the parties—are adopted into common industry practice in western Canada will therefore be interesting to watch.

The full scope of upstream development agreements and strategies for some Canadian LNG projects will also depend in part on the characteristics of the natural gas reserves being exploited. Different upstream development and operating costs will apply to different upstream resources—including for reasons such as reservoir characteristics, the availability of local infrastructure and labour costs—with the commercial viability of a proposed project potentially hanging in the balance. For example, a distinction is often drawn between integrated LNG projects to be fed by natural gas reservoirs requiring unconventional production operations and those to be fed primarily by conventional operations, the former often involving significantly higher costs than the latter. An integrated LNG project relying on unconventional reservoirs is also likely to be more closely scrutinized by project lenders, given the tendency of unconventional reservoirs for less predictable long-term production profiles. So too will the composition of the natural gas produced by an integrated LNG project be an important consideration; not all natural gas is created equal, and some natural gas will require more processing prior to liquefaction than will others depending on the circumstances (including, for example, the preferences of downstream buyers). By contrast, these considerations will be of less importance in the context of merchant model projects and third party tolling projects.

Towards this end, it is important to note that much Western Canadian natural gas is sourced from unconventional reservoirs requiring multi-stage and multi-well fracturing (or ‘fracking’) development operations. So too is it important to appreciate that these formations—including BC’s Montney, Cordova, Liard and Horn River formations—vary in characteristic from wet to dry while also varying in other economically sensitive components. This is of particular consequence given that many Asian natural gas consumers (ie utilities) have a strong preference for higher thermal value natural gas than their Canadian counterparts, a predisposition resulting from their historic reliance on Pacific basin-sourced LNG (and its

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102 See Roberts (n 13) 5–8, 11–14.
typically higher liquids content) and the consequent operating configurations of many Asian power generation facilities.103

For example, while some proposed West Coast integrated LNG projects have been benefitting from initial production consistently marked by high-thermal value, sweet, liquids-rich natural gas streams, others have been wrestling with more disappointing results, including low-thermal values, dry gas and relatively high concentrations of impurities. For project participants in the latter category, results of this nature can mean reduced LNG sales prices (eg because of lower thermal values), limited ability to take advantage of auxiliary profit making opportunities available from BC’s existing processing and transportation infrastructure (eg the stripping and sale of associated butane, ethane and/or propane), the need to engage in additional processing prior to liquefaction (eg the removal of hydrogen sulphide) or the potential attraction of additional regulatory liabilities (eg penalties imposed on the venting of carbon dioxide stripped from produced gas). Conversely, an important characteristic of Western Canadian integrated LNG projects compared to those in many other jurisdictions is the ready availability of local markets and processing and transportation infrastructure, whether desirable for the purposes of selling associated natural gas liquids for collateral revenues or for ‘spiking’ produced gas to increase its thermal value.104

Pipeline transportation

As discussed, different LNG projects will require different levels of investment in transportation infrastructure alongside capital investment in the LNG facility and terminal. In particular, except possibly in the case of a floating LNG facility located immediately above an offshore block, most LNG projects will likely require at least some newly commissioned pipeline infrastructure. Also as discussed, pipeline transportation infrastructure can be built, owned and operated by the project proponents as a project asset alongside the liquefaction facility or can be built, owned and operated by specialist third party operators on a for-profit, fee for services basis.

In the Canadian context, the development of necessary pipeline infrastructure has been a principal focus for the mega-projects planned for the Northern coast of BC. The natural gas production regions of Northeast BC and Alberta are separated from the Pacific coast by hundreds of kilometres of heavily forested, extremely sparsely populated mountainous terrain subject to cold, snow-filled winters and relatively wet summers. This has made the design, engineering and negotiation of acceptable pipeline transportation arrangements a foundational and heavily negotiated aspect of these projects from their inception. So too has pipeline development been at the core of First Nations negotiations in Western Canada. It is also important to highlight that the midstream natural gas operators with whom the proponents of Western Canadian LNG projects have been engaging are highly sophisticated companies with long-established regional operations, and include some of the largest midstream operators in the world.

While there is no general rule applicable to the integration of pipeline infrastructure into the wider Canadian LNG projects of which they form a part, it is interesting to note that a number of different

103 Indonesia, Malaysia and Brunei had no domestic petrochemical industries and no domestic markets for natural gas fractions such as propane and butane when they began exporting LNG to Japan in the 1970s, meaning that they had no economic impetus to strip these components prior to shipment. These fractions therefore remained in shipped LNG cargos, the higher thermal content of which the Japanese set as the basis of their power generation configurations. When South Korea and Taiwan later began importing LNG, such LNG was sourced from many of the same facilities as Japanese-bound LNG, with the result that their domestic power generation industries adopted similar, high thermal content configurations. By contrast, North American natural gas production and consumption developed alongside markets for natural gas’ various fractions. This lead to the stripping of heavier fractions such as propane and butane for separate uses while power generation was largely configured around the remaining methane. China and India are generally less concerned with thermal values of imported LNG given that, as relatively recent entrants to the LNG industry, they are accustomed to a wider mix of natural gas sources and constituent fractions.

104 See Roberts (n 13) 5–8, 11–14. See also Kay and Roberts (n 2) 16.
approaches to pipeline development, ownership and connectivity are being taken by proponents of some of the largest LNG projects proposed for BC.

The Coastal GasLink Pipeline Project (CGLP) being developed by a subsidiary of TransCanada Pipelines Limited (TCPL) to feed the liquefaction facility under development by LNG Canada,\(^\text{105}\) for example, was designed to be owned by two limited partnerships, one of which will own the eastern portion of the pipeline and one of which will own the western portion of the pipeline.\(^\text{106}\) While each limited partnership is anticipated to be majority owned by TCPL, such bifurcated structure is intended to allow for ‘potentially different ownership interests in each of the eastern and western portions’ of the pipeline by the project proponents owning equity in LNG Canada (being Canadian affiliates of Royal Dutch Shell, PetroChina, Kogas and Mitsubishi).\(^\text{107}\) The CGLP project description also anticipates each of these Canadian affiliates entering into separate transportation service agreements (TSAs) with TCPL.\(^\text{108}\) In total, this approach is presumably attributable to the fact that, unlike some other integrated BC LNG projects, the shareholders in LNG Canada are supplying the facility’s feedstock natural gas in part from individually owned upstream assets separated somewhat geographically rather than from a single, jointly owned and operated upstream resource base,\(^\text{109}\) and that for this reason it is desirable for different parties to be responsible for underwriting different percentages of the costs of the CGLP’s development and operation.

By contrast, the project description filed in connection with the Prince Rupert Gas Transmission Project (PRGT) being developed by another subsidiary of TCPL to service the Pacific NorthWest LNG liquefaction facility under development by a consortium led by a Canadian affiliate of Petronas envisions ownership by only a single TCPL limited partnership as well as only a single TSA between such TCPL partnership and the Petronas affiliate.\(^\text{110}\) This streamlined approach is likely attributable to the fact that, unlike with the LNG Canada project, the participants in the Pacific NorthWest LNG project jointly own their upstream assets by means of a project-specific joint venture.\(^\text{111}\) Other comparisons between the two are also illuminating. Similar to the CGLP, the PRGT project description anticipates that the PRGT will enjoy connectivity to the NOVA Gas Transmission Ltd (NGTL) system linked through various networks to the major producing areas of the Western Canadian Sedimentary Basin (WCSB), although in the case of the PRGT this is anticipated through a proposed extension of the NGTL system.\(^\text{112}\) Unlike the CGLP project description, the PRGT project description also anticipates connectivity with Spectra Energy Corp’s BC Pipeline (SEPL),\(^\text{113}\) which has the benefit of providing greater access to the far Northeast of BC than is currently available on the NGTL.

Towards this end, it is important to highlight that the proximity of proposed Western Canadian integrated LNG projects to existing pipeline infrastructure allows these project proponents some flexibility and risk mitigation opportunities in respect of sourcing feedstock natural gas. For example, regardless of whether an integrated project is structured around individually or jointly owned upstream production, such pre-existing regional infrastructure allows the integrated project participants to supplement equity natural gas feedstock

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\(^{105}\) As of the time of writing, LNG Canada is co-owned by affiliates of Royal Dutch Shell, PetroChina, Kogas and Mitsubishi.


\(^{107}\) ibid.

\(^{108}\) ibid 1-3–1-4.


\(^{111}\) See Pacific Northwest LNG Ltd Export Licence Application and Appendices <https://docs.neb-one.gc.ca/ll-eng/lisapi.dll?func=ll&objId=970897&objAction=browse> accessed 24 July 2015. As of July 2015, the participants in the Pacific NorthWest LNG project are Petronas, Sinopec/Huadian, Japex, Indian Oil Corporation and PetroleumBRUNEI.

\(^{112}\) See Prince Rupert Project Description (n 110) 9; Coastal GasLink Environmental Assessment (n 106) 1–3.

\(^{113}\) Prince Rupert Project Description (n 110) 9.
with feedstock acquired from arms-length, non-project third parties at market hubs such as AECO/Nova Inventory Transfer (NIT) or Spectra/Westcoast Station 2. In terms of flexibility, these market hubs could allow integrated project participants to commence liquefaction operations with a combination of equity and third party feedstock while considering additional upstream acquisition opportunities to replace the need for third party purchases. In terms of risk mitigation, the ready availability of third party natural gas supplies may assist in the event of upstream operational difficulties or localized force majeure that threaten the parties’ ability to ensure that commitments to downstream LNG buyers will be timely met through equity feedstock alone.

That said, the utilization of pre-existing pipeline infrastructure is also capable of resulting in not insignificant complications. Under Canadian pipeline regulation, where a pipeline is purpose-built to service a discrete customer or set of customers along a closed delivery route the pipeline owner and shippers will be free to negotiate customized TSAs tailored to their specific requirements, including in respect of applicable tolls, unplanned interruptions and force majeure. By contrast, where a pipeline is ‘common carrier’ infrastructure relied on by multiple shippers to market their production to different destinations, applicable TSAs will be subject to standard terms and conditions approved by the applicable federal or provincial regulator, as is the case in respect of both the NGTL and SEPL. As will be discussed in further detail in the sub-Section ‘LNG Project Structure and Risk Allocation and Mitigation in Canada’ of this article below, such inflexible, non-project specific TSAs disrupt the seamless implementation of the project parties’ preferred risk allocation structure along the value chain. Other complications are also possible, including where a liquefaction facility seeks to enlist capacity on pipeline infrastructure operated by a utility servicing retail and industrial power consumers, as is the case with the Woodfibre LNG project proposed for Southwestern BC just north of Vancouver in Squamish, BC. Here LNG project proponents will need to not only navigate standard form TSAs, but also a regulatory mandate that includes having regard for the best interests of electricity end-users.114

First nations and the duty to consult

The Canadian constitution establishes a number of protections regarding the traditional rights of aboriginal or ‘First Nations’ peoples.115 In the context of the development of a LNG export project, the most significant of these is the duty of the Crown or Canadian government to consult with First Nations groups regarding a project that could impact their rights and, where appropriate, to mitigate any infringement of and/or accommodate their traditional rights.116 Such duty to consult is relatively easily triggered given that any governmental action that may impact on a First Nation’s traditional right or interest will activate the duty.117 That said, the actual level of First Nations consultation required will vary depending on the circumstances, including consideration of the apparent merit of the First Nation’s claim as well as the degree of impairment to such claim posed by the proposed project.118

Although the duty to consult is expressed as one burdening the Canadian government, in practice it is typically the sponsors of a project that assume the management and cost of the consultation process which, depending on the scope of the project and number of First Nations groups potentially affected, can be a considerable undertaking.119 As provided by the ‘Guide to Involving Proponents When Consulting First

114 See generally the Utilities Commission Act, RSBC 1996, c 473.
115 Constitution Act, 1982, s 35(1), being Schedule B to the Canada Act 1982 (UK), 1982, c 11, which states that ‘[t]he existing aboriginal and treaty rights of the aboriginal peoples of Canada are hereby recognized and affirmed’.
117 Haida ibid.
118 ibid; Holub and others (n 116) 310–11.
119 Holub and others (n 116) 311.
Nations in the Environmental Assessment Process’ issued by the BC Environmental Assessment Office, consultation may involve, amongst other things, providing information about the proposed project to First Nations early in the planning process, obtaining and discussing with First Nations information about specific traditional interests that may be impacted by the project, considering modifications to project plans to avoid or mitigate impacts to First Nations’ traditional interests, and meticulously documenting the consultation process for presentation to those authorities who will ultimately be responsible for deciding whether the duty to consult and mitigate has been met by the project.120

That is not to say that government will be absent from this process, and in BC we have seen a concerted effort by the province to encourage positive relations between LNG project proponents and local First Nations groups, including the announcement by BC’s Ministry of Natural Gas Development to work with applicable provincial and federal agencies to ‘develop specific First Nations negotiation mandates for pipeline corridors, LNG plant locations and marine traffic routes to facilitate rapid investment in LNG facilities’.121 Amongst other things, this has led to ‘framework agreements’ with numerous First Nations relating to the various new pipelines proposed for Northern BC, as well as related benefits sharing negotiations.122 For example, news releases issued by BC indicate that it has engaged with 19 First Nations in respect of the PRGT alone, and that 14 agreements related to the pipeline and facility have been finalized.123 Towards this end, however, it is important to highlight that the duty to consult does not impose on project proponents or the government a hard requirement to obtain the consent to the project of an affected First Nation, but rather the commitment to meaningful consultation with a view to mitigation and/or accommodation conducted in good faith.124 Stated somewhat differently, Canadian law recognizes that government must reasonably balance potential negative effects on traditional First Nation’s rights with other facets of the public interest.

A principal practical result of the duty to consult First Nations people under Canadian law is the regular negotiation and execution of ‘capacity funding agreements’ and ‘impact benefits agreements’ among project sponsors and local First Nations groups, and this has been no less the case in respect of proposed Western Canadian LNG projects.125 The former are arrangements pursuant to which project sponsors agree to provide a First Nation with financial funding to facilitate their meaningful participation in the consultation process, including in some cases to cover the costs of separate environmental consultants or legal counsel.126 The latter are arrangements pursuant to which project sponsors agree to share the benefits of a project with a First Nations group, including potentially committing to education and training programmes, employment opportunities, and favourable contracting or procurement opportunities.127 While there is no legal requirement under Canadian law which compels project proponents to enter into either ‘capacity funding agreements’ or ‘impact benefit agreements’ or for consultation processes to involve economic compensation or benefits to First Nations groups, it has become common practice for industry to do so as a means of seeking to mitigate First Nations and regulatory risk.128 Of course, some proposed Canadian LNG projects go

123 ibid.
124 Haida (n 116); Holub and others (n 116) 310–11.
126 See Gilmour and Mellett ibid 386–87; Killoran and others ibid.
127 ibid.
128 ibid.
farther, involving one or more First Nations groups as equity participants intimately involved in project scoping and development.129

In total, the plethora of First Nations groups potentially affected by proposed LNG export projects, the importance of Canada’s budding LNG industry to Western provinces, and a series of important recent judicial pronouncements on the scope and substance of First Nations rights under Canadian law, including several high-profile judgments of the Supreme Court of Canada, will likely combine to contribute to an important broader discussion regarding the fair balancing of national economic development and the protection of First Nations traditional rights. On the one hand, it is imperative that Canadian economic development not be unduly restrained or handicapped by a requirement to satisfy all demands of each community potentially affected by a proposed project or by the application of an unreasonably inflated concept of ‘social licence’. On the other hand, industry must appreciate the legitimate interests of First Nations groups in protecting and preserving their traditional rights and culture in the face of significant infrastructure projects, and strive to increasingly view First Nations groups as long-term project partners rather than mere local stakeholders.

4. LNG PROJECT STRUCTURE/ECONOMIC MODEL AND RISK ALLOCATION

Once one or more LNG project proponents have decided to explore the development of a LNG project, a preliminary consideration will be the optimal project structure or ‘economic model’ to adopt.130 A number of different approaches are available, and these can be roughly separated into 4 different categories as follows:

- Merchant Model
- Third Party Tolling Model
- Project Tolling Model
- Integrated Project Model

That said, such categorization is based on broad strokes, and while very much useful, is also of only so much value. A variety of hybrid approaches are possible, and different LNG projects falling within the same general category can have significant differences. So too can the exact economic model or overall commercial participation adopted in a singular LNG project vary between the project participants.131

Merchant model

Under a pure merchant model structure (Figure 1), the owner/operator of the LNG facility (or ‘project company’) does not engage in upstream natural gas production but rather acquires feedstock natural gas from one or more arm’s length third parties through gas sales and purchase agreements. The project company then liquefies the feedstock natural gas before selling the resulting LNG to one or more downstream, third party purchasers through LNG sales and purchase agreements.

As in an integrated project, but unlike in a tolling model, the merchant model involves the project company taking title to the natural gas and LNG alongside custody of these commodities. Also as in an integrated project, but unlike in a tolling model, the merchant model does not require the incorporation of a

129 For example, following 2 years of negotiations, the Haisla First Nation signed an impact benefits agreement with the original proponents of the Kitimat LNG project, which included an option to purchase a 35% equity position. However, when the original proponents sold the project to Apache Corporation, the Haisla sold the option for $50 million as part of the divestiture. Other proposed LNG projects in BC which include equity participation by First Nations include Cedar LNG (Haisla First Nation) proposed for the Kitimat area as well as the Steelhead LNG project (Huu-ay-aht First Nation) proposed for Sarita Bay on Vancouver Island.

130 See Weems and Hwang (n 5) 280–84.

131 As noted by Kay and Roberts (n 2) 19, ‘[i]n reality, project participants are unlikely to be invested in all of the components [of the LNG project] and may have varying equity interests where they are invested’.
liquefaction tolling agreement within the value chain—the cost of liquefaction may simply be treated as an overhead operating expense assumed by the project company for its own account.

A merchant model LNG project may not involve the construction of significant new pipeline infrastructure to transport feedstock natural gas to the LNG facility. Rather, a merchant model project structure is often adopted in close proximity to robust and reliable existing natural gas production and infrastructure from which the project company can readily source feedstock natural gas. A merchant model LNG project is also more likely to include a project participant who counts significant midstream energy services experience or capability among their overall business operations.

The most distinguishing feature of a merchant model LNG project is that the LNG facility is intended to be, and is operated as, a distinct profit centre or for-profit enterprise. Because natural gas is purchased from arm’s length, non-affiliated third parties and the resulting LNG sold to arm’s length, non-affiliated third parties, the LNG “project” can also be understood as being largely restricted to the LNG facility itself, particularly if title to feedstock natural gas is only assumed by the project company at the inlet to the LNG facility and if the LNG is sold on a “FOB” basis. This makes the merchant model an unsuitable approach where the primary objective of planned equity participation in a LNG project is securing long-term supplies of LNG for downstream consumption. Finally, because the project company is engaging in the merchant buying and selling of natural gas/LNG, the project company is directly exposed to commodity risk and fluctuations in the price of natural gas and LNG in a manner not experienced by LNG project companies under certain other project structures.

A. Third party tolling model

A pure third party tolling LNG project (Figure 2) is similar to a pure merchant model project in that the LNG facility or project company will not be affiliated with either the upstream value chain participants or the downstream value chain participants. Rather, like a pure merchant model LNG project, a pure third party tolling LNG project will be designed and operated as a distinct profit centre. The difference here is that, while a merchant model LNG project will secure a profit from the sale of LNG at a price great enough to more than recoup the costs of natural gas procurement and liquefaction operations, the third party tolling project need only provide liquefaction services at a price great enough to more than recoup the costs of operating the liquefaction facility.

Unlike the merchant model project company, the third party tolling project company will not take title to the natural gas or LNG alongside custody of these commodities. Also unlike the merchant model project company, the third party tolling company will have no responsibility for securing either feedstock natural gas or downstream buyers for the resulting LNG. Rather, such activities will be the concern of the customer(s) of the third party tolling project company who engages it for liquefaction services. Unlike the merchant model project company, such disassociation from the buying and selling of natural gas and LNG has the

132 Note that ‘for profit’ regasification facilities and arrangements are also possible; see Kay and Roberts (n 2) 18.
effect of greatly insulating the third party tolling company from commodity risk. Like the merchant model, a principle project risk of a third party tolling LNG project will be operating risk.

Similar to the merchant model, a pure third party tolling LNG project can be understood as being limited to the LNG facility itself, and therefore an unsuitable approach where the primary objective of a LNG facility equity participant is securing long-term supplies of LNG for downstream consumption. So too is the third party tolling model an unsuitable approach where a primary objective of a LNG facility equity participant is engaging in downstream merchant sales. Like the merchant model, a third party tolling LNG project is often spearheaded by a midstream energy services operator and is considerably reliant on the presence of significant pre-existing local natural gas production, markets and transportation infrastructure. Liquefaction fees charged under the liquefaction tolling agreement(s) will typically be bifurcated, with a fixed fee charged for the reservation of liquefaction capacity and an additional fee charged for liquefaction services actually provided (ie they will be structured as ‘use or pay’ agreements).

**Project tolling model**

A pure project tolling structure (Figure 3) differs most from a third party tolling structure in that the LNG facility or project company will be owned by (and affiliated with) the project proponents participating upstream and/or downstream of the LNG liquefaction facility. Such organization of liquefaction services as a separate and distinct project component may be pursued for a number of different reasons and may have a number of different effects.

First, the fees charged for liquefaction services by a project tolling company will typically be lower than those charged under the third party tolling model, given that the fee is being charged to affiliated entities. Second, the project tolling company will typically benefit from greater risk insulation under the value chain agreements than is experienced by a third party tolling company, including in respect of operational risk.

This is because a common reason for adopting the project tolling model is to facilitate project finance whereby the project company borrows the funds necessary to construct the LNG facility against its revenue entitlement under fixed, long-term liquefaction tolling agreement(s), which likely again include a substantial fixed fee charged for the mere reservation of liquefaction capacity (whether or not such capacity is actually used or not). It is therefore only necessary to ensure that liquefaction fees charged are sufficient to recoup capital expenditures and operating expenditures while also paying down project debt: ie a profit component will be far less of a concern as the project company will be viewed primarily as a financing vehicle and not as a for-profit enterprise. Similarly, the greater risk insulation experienced by the project entity, the more favourable the project finance terms it will be able to attract.
As in a third party tolling structure, the project tolling company will not take title to the natural gas or LNG alongside custody. Unlike a third party tolling structure, a project tolling LNG structure is more likely to be adopted where significant new infrastructure is necessary to unlock otherwise stranded or isolated natural gas reserves. Also unlike a third party tolling structure, a project tolling LNG structure does not bring with it the increased likelihood of the equity participation of a midstream service provider at the level of the LNG facility itself.

The project tolling model shares many characteristics with the integrated project model, with the exception of the necessary involvement of a formal tolling arrangement. Furthermore, like the integrated project model, such characteristics have the effect of making the project tolling model a favourite of both large integrated oil companies with significant upstream production and downstream marketing operations as well SOEs or utilities primarily concerned with satisfying downstream demand. In this light, it may be more appropriate to view the project tolling model as a subset of the integrated project model rather than a distinct LNG project economic model in its own right.

**Integrated project model**

A pure integrated LNG project (Figure 4) is characterized by the equity participation of the project proponents in two or more of a project’s components in consistent percentages. Stated differently, a pure integrated LNG project may feature each project party owning the same percentage of dedicated upstream natural gas production rights, supplying the same percentage of feedstock gas, owning the same percentage of the LNG liquefaction facility and associated pipeline infrastructure, and being entitled to the same percentage of the LNG output of the LNG facility. This is not to say that the ownership percentages of the project proponents will be consistent as between one another (eg four project proponents each owning 25 per cent of each project component), but rather that the ownership percentage of each project party will be consistent across the project components (eg Party A will own a 20 per cent interest in each project component and Parties B and C will each own a 40 per cent interest in each project component).

One attraction of the integrated project model is that consistent ownership across multiple project components results in equal exposure to value chain risks and the possibility of, and the consequences of, failure in
a value chain component. Consistent ownership percentages across project components can also result in far greater alignment of interests than would otherwise be the case as well as facilitate project decision-making, both before final investment decision as well as afterward. Like a project tolling structure, an integrated project structure is more likely to be adopted where significant new infrastructure is necessary to unlock otherwise stranded or isolated natural gas reserves. On the other hand, integrated project models have historically been less common (or more complicated) where the host government is determined to take a compartmentalized equity position in the project.

Although integrated LNG projects (Figure 4) can feature integration both upstream and downstream of the LNG liquefaction facility, it is generally fair to say that upstream integration is more common. This is due to the fact that, while project parties will share in the ownership of the same liquefaction facility, they will likely be engaging one or more different regasification terminals downstream of the facility. Whether or not integration involves the co-ownership and co-development of the same specially-dedicated upstream natural gas resources will in good part be dependent on the characteristics of the upstream production region. Where a project is dependent on a single or small group of specially issued concessions or production licences, diffused holdings will likely neither be possible nor desirable. Where non-unified upstream holdings are possible, whether or not project proponents choose consolidation will likely depend in part on any current holdings of the project proponents in the source production region, the size of such current holdings relative to the project’s proposed export capacity, reasonably foreseeable upstream acquisition opportunities, and gathering, processing and transportation considerations.

The integrated LNG project model has proven very popular with many of the largest participants in the LNG industry, including vertically integrated multinational energy companies, diversified interest holders, SOEs and large utilities. For vertically integrated multinational energy companies and diversified interest holders, the integrated model can provide for the marriage of upstream natural gas resources with downstream LNG shipping, trading and marketing operations. For SOEs and utilities, the integrated model can satisfy downstream demand through the acquisition and development of dedicated upstream supply sources.

Like the merchant model, an integrated project model will typically involve title to the natural gas passing from the upstream project parties to the LNG project company or a joint marketing company pursuant to a gas sales agreement, with the important difference that the price paid may be different than that which would result in an arms-length transaction. The project company or joint marketing company would then engage in

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133 As articulated by Weems and Hwang (n 5) 279–80, ‘in a fully integrated LNG chain, all parties are effectively exposed to all risks in the LNG chain since failure in any part of the chain affects all other parts’.

134 See Weems and Hwang (n 5) 283.
the sale of the resulting LNG to the downstream buyers, whether affiliated or non-affiliated. Finally, like the merchant model, the integrated project model does not necessarily require the incorporation of a standalone liquefaction tolling agreement.

Hybrid project structures and economic models

As stated above, while the characterization of LNG projects as either adopting the merchant model, third party tolling model, project tolling model or integrated project model is very much useful, such fixed categories are only of so much utility. The international LNG industry is evolving rapidly, and increasingly complex project structures and economic models continue to emerge. This can likely be attributed to a number of factors, including the steady growth in the volume of LNG trade, the increasing number of LNG export and import markets, advances in LNG liquefaction, storage and transportation technology, the increasing number of LNG industry participants and the increasing sophistication of these industry participants. The result is innovative approaches to LNG project design, modelling and participation, with a single LNG project capable of incorporating multiple different commercial strategies.135

An illustrative example is provided by the following hypothetical North American LNG export project (Figure 5).

Party A is a major energy services and infrastructure company with no significant upstream development or downstream marketing interests. Party B is a South Asian SOE with operations across the LNG value chain. Party C is a joint venture between another international integrated LNG player and the LNG arm of a major international maritime transportation company. Party D is a large European integrated utility company whose core operations are complimented by a portfolio of international upstream natural gas production interests.

135 See also Kay and Roberts (n 2) 28.
Pipeline Company, a wholly-owned subsidiary of Party A, builds and owns relatively modest new-build pipeline infrastructure necessary to connect the LNG facility to the existing regional natural gas transportation grid, and Party A provides operating services both to the LNG Facility Company and the Pipeline Company. Parties B, C and D obtain natural gas feedstock through a combination of equity upstream production and market/index purchases from third party producers/vendors, and each of Parties B, C and D have contracted for one-third of the LNG facility’s liquefaction capacity. Party A obtains revenues through its operating agreements with LNG Facility Company and Pipeline Company and through its majority equity ownership of these entities. On the other hand, Parties B, C and D mitigate the cost of liquefaction services procured under their respective liquefaction tolling agreements through their minority equity ownership of the LNG Facility Company.

A myriad of other configurations are possible. Take, for example, this second hypothetical North American LNG export project structure (Figure 6).

Here Party A and Party B, both SOEs from the same East Asian jurisdiction, form an upstream joint venture 50 per cent owned by each company for the purpose of acquiring equity upstream natural gas production to serve as the majority of feedstock for liquefaction operations. To the extent circumstances dictate (eg acquisition opportunities), the joint venture parties agree to acquire remaining necessary feedstock either from third party producers/vendors or from additional equity upstream acquisitions. Party A and Party B each also own the JV Marketing Company and Train 1 Company as to 50 per cent, and each have a 25 per cent ownership interest in the Common Facilities Company. Party A is participating in the LNG project primarily to secure long-term LNG supplies for sales to a portfolio of other SOEs from its home jurisdiction. Party B is a utility and is participating in the LNG project primarily to secure natural gas for its own downstream consumption. The obligations of the JV Marketing Company under its liquefaction tolling agreement...
(LTA) have been guaranteed by the home nation of Party A and Party B. In turn, the revenue entitlements of Train 1 Company under the LTA have underwritten project finance obtained by Train Company 1 to cover the costs of development and construction of the first train as well as 50 per cent of the costs of the common facilities.

Party C is a publically-traded international energy company with operations across the entirety of the LNG value chain. It has more than sufficient local equity upstream production to utilize the entirety of the second train’s capacity. Each of the Marketing Company, Train 2 Company and LNG Plant Operating Company are wholly-owned affiliates of Party C. Party C does not require project finance to fund the costs of development and construction of train 2 or its 50 per cent share of the costs of the common facilities (which it plans to do from cash flow), and it is this fact, along with the parties’ different preference for the sourcing of feedstock natural gas, that primarily explains this particular approach to project structure. Also of significant importance is the fact that Party C will be entering into LNG sales and purchase agreements with non-affiliated, arm’s length third parties. Party C has also reserved/dedicated a portion of train 1’s liquefaction capacity for short-term arrangements and spot sales (although indirectly through a downstream, ‘aggregator’ affiliate). Destination flexibility was a heavily negotiated LNG SPA component with the result that Party C is prohibited from selling LNG to the home jurisdiction of Party A and B while A and B are limited to deliveries to the same jurisdiction.

Party C, through the LNG Plant Operating Company, will be providing operations and maintenance services to Train 1 Company, Train 2 Company and the Common Facilities Company, in each case at close to cost. Party C has also taken a 50 per cent interest in Pipeline Company (along with a corresponding obligation to fund 50 per cent of the costs of development and construction of the significant new-build pipeline infrastructure necessary to connect the parties’ upstream natural gas production to the LNG facility). This arrangement was attractive to Party C as a means to mitigate the tariff paid under its TSA as well as to participate in the revenues generated by the TSA entered into by the Party A/Party B Upstream JV. This arrangement was attractive to the midstream energy services company owning the remaining 50 per cent interest in Pipeline Company as means of reducing its capital expenditure obligations and risk exposure in respect of the new-build infrastructure. The midstream company has also retained a call option on Party C’s interest in the Pipeline Company exercisable for a certain period following the commencement of commercial operations.

A number of additional points on project structure and economic modelling are worth highlighting further to these hypothetical project scenarios. Project structure is not written in stone, particularly during the development phase and pre-final investment decision and as different proponents join or depart a proposed project. Some LNG projects are initially advanced by a single project proponent who unilaterally undertakes ground site acquisition, front-end engineering and analysis, regulatory applications, upstream feedstock acquisition and/or negotiations with applicable transportation providers or midstream operators prior to inviting the participation of project co-sponsors. Such project development may also involve the drafting of project development agreements and/or project ownership agreements (whether unincorporated joint ventures, incorporated joint ventures or general or limited partnerships) which contemplate or institute a specific project structure and economic model into which co-sponsors will be expected to buy-in or adopt. By contrast, other LNG projects may be pursued by committee and with a consortium of project proponents joining forces and sharing a common vision (to varying degrees of detail) from the inception of project development work. Here project structure may change as the finer challenges or circumstances presented by a project come into greater focus, including, for example, a desire to incorporate local stakeholders. Still other changes in direction may result from external forces or developments occurring over the course of a LNG project’s development, whether a significant transformation of market conditions or the non-negotiable requirements of project lenders.
LNG project structure and risk allocation and mitigation in Canada

LNG projects face a diverse set of risks. These are capable of manifesting at different stages of the value chain and will have follow-on effects on the other components of the value chain. The allocation of such risks will also in large measure be determined by the economic model adopted by the LNG project, subject to the negotiations of the project parties during the adoption of such economic model. Most importantly, however, risk allocation must be implemented systematically across the series of agreements comprising the value chain to ensure that risk allocation functions cohesively without gaps or conflict. Furthermore, the more complicated a project’s structure is (eg in terms of the number of project entities and value chain arrangements between them), the more careful attention this will require.

Such systemic implementation and allocation of project risk should be conducted on a number of different (but very much interrelated) levels.136 At the contractual level, project counsel must ensure the appropriate alignment of contract durations, information sharing obligations, force majeure rights and termination rights, among others. At the economic level, revenue flows and the financial consequences of force majeure, unplanned interruptions, supply disruptions and performance failures must be appropriately organized to ensure that different project risks have been saddled with the appropriate project participants or entities. At the physical level, the seamless delivery of gas, storage, offloading of LNG and the arrival and departure of LNG vessels—as well as the maintenance of all ships and facilities—must be anticipated and coordinated, with appropriate mitigation strategies and solutions put in place. Nor are these considerations evaded by those participating in only a single segment of the LNG value chain: a significant malfunction in one link of the value chain can easily have a domino effect across the remainder of the procession, undermining the long-term financial welfare of each project participant.137

Given their remote location and the amount of new-build pipeline infrastructure required, construction risk will likely be front of mind for sponsors of the large LNG projects proposed for BC’s Northwest coast. Considerations will include allocation of liability for expenses resulting from cost escalations, delays in final commissioning, and any shortfalls in designed operational capacity. These will need to be allocated amongst the project parties, including EPC contractors, pipeline and liquefaction facility owners and operators, and LNG offtakers. Many different questions can be asked. Will delays in construction trigger liquidated damages payable by the EPC contractor? To which project parties will these be applied and in what manner, eg in lower liquefaction tolling fees paid by a LNG marketer, in lower LNG purchase prices paid by the LNG offtaker, in both? How should such liquidated damages payable interact with project finance arrangements? Has the LNG marketer agreed to a firm offtake date or window? If this date is not met, are downstream liabilities incurred by the LNG offtaker to be shared by the project parties and, if so, on what basis and who will be primarily charged with mitigating such liabilities by arranging for replacement LNG?

Similar concern will likely be focused in the Canadian context on operational issues related to liquefaction facilities and pipeline infrastructure following their commissioning and start-up for the same reasons. How will risks associated with unplanned interruptions or curtailments to pipeline or liquefaction capacity be allocated? Will these rest entirely with one project party (eg the pipeline or liquefaction facility operators) or will risk be apportioned between two or more project parties (eg a jointly-owned marketing company and the LNG offtaker)? In what circumstances will an unplanned interruption or curtailment in pipeline or liquefaction capacity constitute an event of force majeure relieving one or more project parties from their performance obligations under the value chain agreements? To what extent will force majeure also relieve a party of its payment obligations under its value chain agreements? To what extent will the onset of force majeure in the different value chain agreements include operational difficulties experienced by project parties that are not a party to the instant value chain agreement? To what extent will force majeure experienced by third

136 See also ibid 27.
137 See also ibid at 25–26; Weems and Hwang (n 5) 279–80.
party service providers be accommodated? To what extent do such operational difficulties need to be outside the reasonable control of the project parties or third parties? How will the risk allocation matrix shift where the unplanned interruption or curtailment does not constitute force majeure by any measure?

Of keen interest to participants in, as well as observers of, the Canadian LNG industry will also be how Canadian projects and the risks they present compare with their US competitors, and here several important high-level distinctions can immediately be drawn. One is that, while the majority of proposed Canadian LNG projects appear to have adopted a variation of the integrated project model structure, the majority of the most advanced United States LNG projects appear to be based on variations of the merchant model or third party tolling model. Another is that, in stark contrast to these US projects, the great majority of proposed Canadian LNG projects are entirely greenfield sites rather than brownfield developments taking advantage of substantial existing facilities and infrastructure.

The basis for such divergent attributes is not difficult to identify. The US Gulf Coast—situated at the heart of the largest petrochemical complex in the world and benefitting from extensive regional natural gas transportation infrastructure and a vigorous gas market—makes possible merchant and third party tolling LNG projects in a manner simply not offered by northern BC. Depending on the preferences of the potential project party, these approaches to project structure also boast a number of appealing traits. From the perspective of a LNG offtaker, the merchant model will be attractive where there is a desire to avoid involvement in upstream activities, whether to maintain streamlined operations or to avoid being subject to local regulators in connection with feedstock procurement or transportation operations. Alternatively, a LNG offtaker may be attracted to a third party tolling project where equity upstream production is viewed as a valuable hedge against a short position as a natural gas consumer. In both cases the LNG offtaker may also desire to avoid the increased costs and exposure to construction and operations risk attendant with equity participation in the liquefaction facility entity. In both cases the LNG offtakers may also view these models as an opportunity to diversify their LNG supply portfolio via what effectively amounts to an option to purchase LNG at a fixed rate (ie in the form of a fixed reservation fee under a third party tolling model or in the form of a cancellation fee under a merchant model). Finally, from the perspective of US regasification facility owners and operators, brownfield LNG liquefaction facilities structured under the merchant model or third party tolling model represent the opportunity to put existing but idle assets to profitable use without the same amount of capital expenditure as would be necessary at a greenfield site.

However, none of this is to say that Canada does not present the possibility of merchant model or third party tolling model LNG projects. In its export application to the NEB, Repsol states that it has engaged in preliminary discussions with natural gas producers in both Western Canada as well as the Appalachia region of the US in respect of sourcing feedstock supplies, which at the very least suggests that a merchant model facility is being given close consideration. This is only reasonable given the presence of existing regional natural gas transportation and processing infrastructure, and it should therefore not be a surprise that the export applications of each of the other proposed Canadian East Coast LNG projects also contain language suggestive of a merchant structure, a third party tolling structure or a possible hybrid of the two. Nor are project

138 Hwang and Gyarsas (n 61). The different attributes of the integrated project model and the merchant and third party tolling models have also resulted in some notable differences in the cast of industry players participating in Canadian and US LNG projects. In particular, while the Canadian LNG race is characterized by the equity involvement of a number of large Asian oil and gas SOEs at the level of the liquefaction entity, including Sinopec, PetroChina, CNOOC, Petronas, Indian Oil Corporation Limited and PetroleumBrunei, Asian oil and gas SOE equity involvement in the US LNG race appears much more limited. For example, as of the time of writing, the only foreign oil and gas SOE (whether Asian or otherwise) with equity involvement in a US liquefaction facility identifiable from publicly available information is Qatar Petroleum with its 70% stake in the Golden Pass LNG Terminal.

139 While the majority of US Gulf Coast projects are brownfield sites, this is not the case in all instances. Note also that the Oregon LNG project and the Jordan Cove LNG project, both located in Oregon, are greenfield sites.

140 Hwang and Gyarsas (n 61).

141 ibid.

142 ibid; Weems and Hwang (n 58).
proposals of this nature strictly limited to Canada’s East Coast. The NEB export application of WesPac Midstream is also indicative of a merchant, third party tolling or hybrid project structure relying on existing natural gas transportation and liquefaction infrastructure (or expansions thereof) owned and operated by FortisBC Energy—a regulated utility—capable of delivering to the Vancouver area natural gas sourced from Northeastern BC via the Spectra/Westcoast pipeline system.143 Securing third party natural gas feedstock from Northeastern BC via Spectra/Westcoast pipelines and FortisBC Energy pipeline infrastructure is also the business plan of the Woodfibre LNG project planned for Squamish, BC. However, given the apparent affiliation between Woodfibre and its downstream LNG offtakers, this project is likely most appropriately characterized as an integrated tolling project rather than a merchant or third party tolling project.144

Also, to the extent index-linked pricing is coveted by LNG buyers, whether as a means of departing from the oil-linked price formulation traditionally dominating LNG trade to Northeast Asia or as a means of portfolio diversification,145 Canadian LNG export projects are similarly positioned to their US competitors. Although discussions of natural gas index-linked LNG pricing formulas have generally been dominated by reference to the Henry Hub pricing offered by US projects, western Canadian LNG projects are able to offer access to a number of natural gas indexes, including in particular AECO/NIT and Spectra/Westcoast Station 2 pricing. These Canadian market hubs also provide for price risk mitigation strategies via derivatives and other hedging instruments similar to the NYMEX natural gas futures contracts linked to Henry Hub.146 Both the Natural Gas Exchange (NGX) and the Intercontinental Exchange (ICE) offer physical and futures contracts linked to AECO/NIT, which is generally considered the most liquid hub in the Western Canadian Sedimentary Basin and among the most liquid on the continent. Futures contracts in respect of Spectra/Westcoast Station 2 are also available, although such instruments generally do not enjoy the same liquidity as those tied to AECO/NIT. Other available price risk mitigation strategies include the acquisition of NYMEX Henry Hub futures gas contracts complimented by contracts to cover the applicable differential (eg between Henry Hub and AECO/NIT, which has historically traded at a discount to Henry Hub) as well as customized over-the-counter derivatives transactions.

A final illuminating point of contrast between Canadian and US LNG projects is provided by the recent investment agreements announced by BC in connection with the Pacific NorthWest LNG project, for which there is no US equivalent. The first is a ‘long-term royalty agreement’ (LTRA) stabilizing royalties payable to BC by the project’s upstream joint venture while also imposing minimum production amounts on the joint

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143 This same Spectra and FortisBC infrastructure is being relied on by the proponents of the Jordan Cove LNG project in Oregon, a proposed third party tolling project that is also looking to take advantage of existing pipeline transportation infrastructure connecting it to natural gas production regions in the US, including in the Colorado/Rocky Mountain area. The same is the case with the proposed Oregon LNG project, whose NEB application indicates a possible merchant/third party tolling model. Unlike the Jordan Cove LNG NEB application, however, the Oregon LNG NEB application suggests that the entirety of its feedstock will be sourced from Western Canada.

144 According to Woodfibre’s NEB application, the international operations of Pacific Oil & Gas Limited, the Singapore-incorporated parent of the Woodfibre entities, include the ownership of LNG receiving terminals and large-scale combined cycle power generation facilities in China. As a result, rather than integration at the upstream and liquefaction levels, Woodfibre LNG would appear to be integrated at the liquefaction and downstream/regasification levels.

145 For a detailed review of the various price mechanisms commonly adopted in LNG SPAs, see Roberts (n 13) 65–76. Note also that, while Henry Hub pricing was initially seen by LNG buyers as a desirable means of long-term price risk mitigation, the collapse of the price of oil from mid-2014 to early 2015 is leading many industry players to now view index-linked pricing more as a means of portfolio diversification. See IGU (n 7) at 17. Criticism of the drive to adopt Henry Hub or other North American natural gas indexes as the base of LNG export prices to Northeast Asia include the prudence of allowing natural gas supply and demand fundamentals in one market to determine the price paid for natural gas in another independent, unrelated and geographically distant market. See Rogers and Stern (n 54) 27, 47. Attractive elements of index-linked pricing include that it ‘allows LNG buyers to clearly segregate the value of the underlying gas commodity from the LNG plant infrastructure’ and is thereby a more transparent pricing mechanism; see Hwang and Gyarfas (n 61).

146 For further discussion of such strategies, see also Foss and others (n 6) 47.
venture. Set to run from the beginning of 2016 through the end of 2038, the LTRA establishes an initial royalty rate of 6.06 per cent which will eventually climb to 13.36 per cent in the agreement’s final year. Production commitments are set at approximately 160 Bcf in the first year climbing to 373 Bcf in the final year, with the JV also undertaking to make minimum infrastructure investments between 2014 and 2020 of $3 billion and $1 billion per year in development activities until annual production reaches 1.85 Bcf/d.

The second is a ‘project development agreement’ (PDA) which provides the Pacific NorthWest LNG project with assurances regarding the stability of certain key regulatory regimes and certain applicable taxes. In particular, subject to a minimum threshold of damages incurred, the PDA requires the payment of compensation by BC to the project in the event of certain specified adverse regulatory developments, being an adverse change in the applicable LNG tax, an adverse change in available natural gas tax credits, a discriminatory increase in applicable carbon taxes, or discriminatory treatment under the Province’s Greenhouse Gas Industrial Reporting and Control Act. Importantly, however, the PDA does not protect the Pacific Northwest LNG project from regulatory changes or legislative enactments of general application which may have negative consequences for the economics of LNG activities in the province, including related to the environment, health or safety.

A legal regime of great relevance to risk allocation and mitigation for major capital investment initiatives such as LNG projects—including where the project proponents have the benefit of bespoke investment agreements with the host government such as LTRAs and PDAs—is that of international investment law and arbitration. This includes the protection offered by bilateral and multilateral investment treaties such as the recent (and much publicized) Canada–China Foreign Investment Protection and Promotion Agreement ratified in 2014 as well as the right to bring an investment claim before such dispute resolution forums as the International Centre for Settlement of Investment Disputes (ICSID). Also, while political risk is generally considered to be low in Canada (particularly relative to some of its competitors in the LNG race), many might be surprised to discover that as of the end of 2014, Canada ranked fifth in the world in the number of investment treaty arbitrations instituted against it by disaffected foreign investors, behind only Argentina, Bolivia, the Czech Republic and Egypt, and just ahead of Mexico, Ecuador and India.

Towards this end, it is important to note the current portfolio of bilateral and multilateral investment treaties to which Canada is a party, which as of the time of publication consists of 36 ‘Foreign Investment Promotion and Protection Agreements’ (FIPAs, as they are called here) currently ratified and in force, 7 FIPAs signed but not yet ratified, 7 FIPAs which remain unsigned although negotiations are said to have been concluded, and 11 FIPAs for which formal negotiations have begun but which remain underway. Also of significance is that Canadian FIPAs/BITs typically do not include ‘umbrellas clauses’, those protective provisions in investment treaties pursuant to which host states are obliged to honour investment agreements

entered into with foreign investors.154 Given that Canada’s book of 37 FIPAs remains somewhat limited compared with some other western industrialized nations,155 equally noteworthy is the typical inclusion of ‘denial of benefits’ clauses in Canadian FIPAs, which substantially reduce the ability of foreign investors hail- ing from countries without a FIPA in force with Canada to engage in ‘investment treaty shopping’ strategies.156 On the other hand, given the lack of constitutionally protected property rights in Canada (to be contrasted with such jurisdictions as the USA), the typical inclusion of the right to compensation in the event of direct or indirect expropriation in Canada’s FIPAs should be of some comfort to those foreign investors with ready access to such treaties.

Canada’s final ratification of the ICSID Convention in 2013 is another important component of the international investment protection regime available to foreign investors in the Canadian LNG industry. Firstly, as 31 of Canada’s 37 FIPAs in force provide for arbitration before ICSID alongside such other international commercial arbitration institutions as the UNCITRAL Model Rules, such ratification provides foreign investors with access to a Canadian FIPA the option of arbitration in this forum conceived specifically (and exclusively) to adjudicate disputes between private investors on the one side and sovereign states on the other side.157 Secondly, for those foreign investors into the Canadian LNG industry without the benefit of an investment treaty with Canada, Canada’s ratification of the ICSID Convention makes possible the inclusion of an ICSID arbitration clause in any discrete investment agreement with the Canadian federal government or the provinces of BC, Alberta or Ontario.158 Such an arbitration clause would also include the possibility of international law being made applicable to the dispute, including its various principles pertaining to state action taken against the property or assets of foreign investors.159

Interestingly, however, neither the LTRA nor the PDA includes an ICSID arbitration clause, the former providing that the parties attorn to the exclusive jurisdiction of the BC courts and the latter providing for arbitration before the BC International Commercial Arbitration Centre as the exclusive dispute resolution forum.160 Indeed, the BC 2015 Liquefied Natural Gas Project Agreements Act stipulates at section 2(2)(e) that LNG project agreements entered into by BC must ‘provide that the venue for any preceding to resolve a dispute arising out of or related to the agreement must be in British Columbia’. The PDA also goes further in providing that the parties agree not to bring any action or claim in any other forum, whether ‘domestic, foreign or international’, including under the North American Free Trade Agreement.161 That said, it is important to appreciate that the ambit of protective provisions included in typical bilateral and multilateral investment treaties extend past specific contractual arrangements and apply to investment project generally, and include such concepts as fair and equitable treatment, full protection and security, national treatment and access to justice and fair procedure.162

155 By comparison, as of July 2015, Germany was a party to 134 BITs, the United Kingdom 104 and the Netherlands 96.
157 Amongst other things, this includes award enforcement mechanisms designed to limit the grounds upon which host states may seek to vacate or otherwise avoid unfavourable awards rendered against them.
158 When ratifying the ICSID Convention Canada designated BC, Alberta and Ontario as constituent subdivisions capable of consenting to ICSID arbitration in their own right.
159 See Ian Brownlie, Principles of Public International Law (7th edn, Oxford University Press 2008) at 519–51.
160 LTRA (n 147) s 13.19; PDA (n 150) s 10.2(c)(i).
161 ibid s 10.2(c)(iii). Chapter 11 of the NAFTA is an investment protection chapter within a larger free trade agreement which establishes investor arbitration rights, including before ICSID.
The LTRA and PDA also include language interesting from a project structure perspective. This occurs in the ‘most favoured nation’ (MFN) clauses included in each agreement, namely those clauses which address the scope of BC’s obligation to consider extending to another BC LNG project proponent under a separate LTRA in the future. Specifically, the LTRA recognizes such a possibility where it ‘would be appropriate in order to achieve generally equitable terms and conditions’ between the subsequent LTRA and the Pacific NorthWest LTRA. Somewhat similarly, the PDA provides that the Pacific NorthWest project will not be entitled to any more favourable treatment afforded to another BC LNG project proponent under a subsequent PDA where in the Province’s reasonable opinion the ‘terms, conditions or benefits’ in the subsequent PDA are not ‘reasonably applicable’ to the Pacific NorthWest project because it ‘is not in a similarly situated position’. Therefore, given the variety of LNG project structures proposed for BC to date, it is not impossible to imagine the need for close analysis regarding the appropriate interpretation and application of these MFN clauses should additional LTRAs and PDAs be concluded with LNG project proponents in comparable, but not quite identical, circumstances.

5. CONCLUSION
This is not Canada’s first brush with LNG. In the early 1980s Dome Petroleum signed an initial SPA with 5 Japanese buyers for the sale of approximately 3 MTPA of LNG from Northwest BC. The project faltered amid economic and regulatory uncertainty, however, with Japanese and other Northeast Asian demand being subsequently satisfied by other projects, including Australia’s historic North West Shelf project.

Much like the early 1980s, various project risks and uncertain economics continue to cloud the future of many Canadian LNG projects. Unlike the early 1980s, on the other hand, the LNG industry can no longer be characterized as a ‘niche’ sector populated by a small club of international players: the LNG industry has experienced momentous evolution and diversification over the past 35 years and LNG demand and trade—and as a result LNG project development—continue to only get more complicated. As recently emphasized by Weems and Hwang, ‘[t]he only constant in the LNG industry again appears to be change – unpredictable change’. The significant entry of Canada into the global LNG market alongside the USA would represent another seismic shift in the industry’s development, the international and domestic intricacies of which therefore warrant being carefully watched.

163 LRTA (n 147) s 13.3.
164 PDA (n 150) s 10.17.
165 See Weems and Sullivan (n 4) 6-20–6-21.
166 See Kay and Roberts (n 3) 24; Griffin (n 4) 12.
167 Weems and Hwang (n 58).