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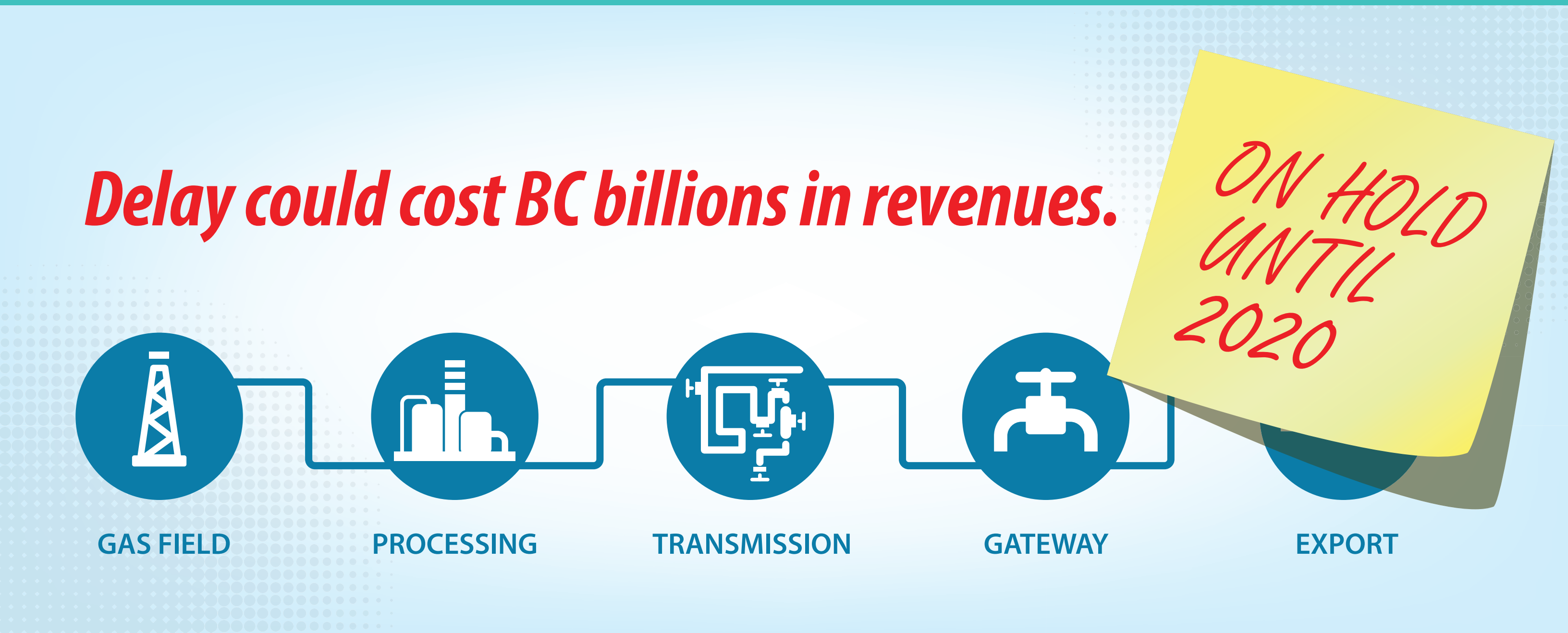

LNG Exports From British Columbia: The Cost of Regulatory Delay

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Main Conclusions

- British Columbia's natural gas resources are substantial, and the international market for liquefied natural gas is growing, particularly in the Asia-Pacific region.
- BC is well placed to serve that market. Under conservative assumptions, BC export capacity could be 42–74 percent of Asia-Pacific imports of LNG in 2020.
- Strong environmental and other protections are necessary, but regulatory and other delays are hindering the ability of BC to compete for those sales.
- The International Energy Agency notes that, because of these delays, "no Canadian LNG project will start production" by 2020.
- Under conservative assumptions—that actual sales of BC LNG to Asia-Pacific importers would be only 11–20 percent of that market in 2020—the annual export revenues lost due to delay would have equated to between 2 and 9.5 percent of BC GDP in 2014, depending on assumptions about export volumes and prices.
- The magnitude of these lost export revenues should encourage policymakers to streamline the regulatory process so that BC is able to make use of its large natural gas resources.

Balancing Community Interests and Aggregate Wealth

Milton Friedman reminded us many years ago that government limited to core activities nonetheless has "important functions to perform" (Friedman, 1962: 34). Among them are efforts to deal with significant environmental harms and other community effects that market participants have insufficient incentives to consider when making decisions on investment, production, and consumption. Regulatory activity can be an efficient constraint on the operation of economic markets, and strong environmental controls in particular are likely to be appropriate for wealthy societies demanding high levels of environmental quality. This is especially the case when political competition among groups forces decision makers to balance such competing interests as environmental quality, economic returns, employment, and resource costs, however crudely; and also when the costs of environmental controls are borne by interests that politically are concentrated rather than diffused, while the benefits are diffused across the population writ large. As the promulgation and implementation of rules and processes protecting community interests are necessarily time consuming, some degree of regulatory delay is appropriate.

Clearly, not all delays in the implementation of large capital investment plans are regulatory in nature; planning, financing, contracting, and other private-sector delays attendant upon the construction of long-lived and complex capital investments are obvious realities. But regulatory delay is a parameter that policy makers can address, and the goal of this study is the provision of reasonable estimates of the economic benefits of a reduction in the time consumed by such policy processes.

Unlike investors and others in the private sector, regulators typically do not bear the economic costs of delay, which can be summarized as the economic benefits of investments and other activities forgone during the regulatory approval process, and perhaps after it if economic conditions prove less remunerative due to the delays. Moreover, regulators themselves can have incentives to impose delays greater than those necessary to effect appropriate safeguards for community interests. This is particularly the case when the costs of delay are borne in substantial part by the economy writ large, rather than by specific interests, and when delays further the interests of particular groups, including those of the regulators, themselves an important interest group pursuing expanded budgets, authority, and perhaps ideological goals as well.[1]

This means that regulators might have insufficient incentives to streamline and expedite regulatory requirements and approvals. Unnecessary delays in approvals for investments and other activities impose economic costs just as relevant as those that would be created by weaker-than-appropriate regulatory safeguards. Both too little and too much regulatory activity in pursuit of environmental protection and other community interests impose unnecessary costs on the economy in the aggregate, and on specific sectors in particular.

This trade-off between environmental protection and the expeditious use of natural resources to increase provincial wealth is a prominent feature of the policy debate over the prospective development and export of BC's natural gas

1 For the classic discussion of this phenomenon, see Niskanen (1975: 617–43). See also Chang, de Figueiredo, and Weingast (2001: 271–92).

resources, in the form of liquefied natural gas (LNG). Moreover, other issues, distinct from environmental concerns, are clearly also important in the context of policy making: Project costs borne by the public sector must be compensated, royalty rates for the use of public lands must be determined either by public officials or through a negotiation process, interprovincial infrastructure issues, if any, must be resolved, and so on. Resolution of such matters is time consuming, but a government dedicated to increasing aggregate well-being must balance efforts to find appropriate answers to these questions with the timely use of resources in ways that maximize overall wealth, defined broadly. A recent study published by the University of Calgary on the British Columbia LNG issue summarizes succinctly the importance of a timely resolution of the various regulatory issues:

> … there are many proposed [natural gas] liquefaction projects around the world and the longer Canadian projects take to move forward, the more likely it becomes that Canadian supplies will be displaced by these other projects. … it is difficult to overstate the importance of acting before the equivalent market share is acquired by competitive nations and companies… (Moore et al., 2014: 2)

Note that a dynamic view of the international market for LNG might, in principle, suggest that the costs of delay could be offset by the economic benefits of pushing investment and other costs into the future, particularly if the growth in the overseas demand for LNG proves faster than the growth in supplies from British Columbia's competitors. After all, inflation-adjusted prices for LNG sales contracts might rise faster than the real market rate of interest, in which case a delay in the production and sales of natural gas resources would prove profitable, because natural gas reserves are a long-lived asset. Production of gas is substitutable over time, that is, a given cubic meter can be produced today and sold at today's price or produced tomorrow at tomorrow's price. Producers must make predictions about the rate at which prices might grow compared with the market rate of interest.

But these possibilities are speculative, and in any event, the mere option of contracting earlier rather than later itself is valuable, and at a crude level can be seen as offsetting the economic benefits of delaying costs or receiving prices growing over time at a rate faster than the market interest rate. Accordingly, it is reasonable for us to assume here that, holding constant protection of environmental quality and other community interests, earlier rather than later regulatory approvals of appropriate projects would be beneficial on net. This by definition is the view of those now or soon to submit applications for project approvals, and such market signals are not to be dismissed lightly. Moreover, choices on the efficient timing of LNG export investments are a matter for the private sector rather than public officials; given the requisite approvals, industry decision makers and investors can make decisions on timing issues.

As discussed in the next section, estimates of the size of BC's natural gas resource vary considerably, but the quantity of marketable gas—its value—is considerable under any of them.[2]

2 A new report (Hughes, 2015) challenges the assumed volumes of gas available for export, and the prospective profitability of those future exports and of exploitation of British Columbia gas resources more generally. As noted below, the dispute over the size and value of the resource is irrelevant for purposes of policy analysis.

Moreover, the potential overseas market for LNG is substantial, but the same is true for production capacity among BC's competitors, both actual and potential.

That there is a dispute about the size of the resource, about future conditions in the international market for LNG, about future economic returns, and so on is unsurprising. It is also irrelevant in a policy context: what should not be at issue is the sharp delineation between the appropriate roles of government and the private sector in this context. It is the job of the government to impose appropriate environmental, safety, and other controls protecting community interests in an expeditious manner; it is not the job of the government to decide which investments are likely to prove profitable, or the timing of such investments. Investment decisions are the job of the private sector. Investors will put their own resources at risk, and thus have efficient incentives to balance expected economic returns with the inevitable risks and uncertainties afflicting investments both large and long-lived. The above-noted University of Calgary study of the British Columbia LNG issue fails to understand this central point about the appropriate division of responsibilities between government and the private sector: "... the regulatory arena ... is the appropriate place to evaluate [the] costs and benefits" of proposed LNG projects (Moore et al, 2014: 2). In brief: No, it is not.

This study summarizes the available data and estimates on the prospective size of the international market for LNG, the likely share of that market for BC, the revenues to be earned, and the economic costs of delay. The next section summarizes recent estimates of the size of the BC natural gas resource and the prospective amounts of LNG available for export, in particular to the Asia-Pacific region. The discussion considers the sources of LNG likely to compete with BC in the world market, and the attendant costs of delay in terms of lost sales revenues under conservative assumptions.

British Columbia Natural Gas Resources in the World LNG Market

Rather than attempting to create a detailed projection of the future market for BC LNG—a task fraught with all of the difficulties and pitfalls inherent in forecasting exercises—this study employs a simpler approach. We use recent analyses and projections available in the literature for the purpose of deriving reasonable ballpark estimates of the parameters of interest, as our goal is to discuss the adverse effects of regulatory delay with respect to the BC LNG export market. We begin with some basic data.

Data on the Recent BC Natural Gas Market

Table 1 shows data for 2000–2014 on British Columbia gas reserves, production, and consumption, as reported by the BC Oil and Gas Commission (2013: Table A2) and the Canadian Association of Petroleum Producers (2015).

The more-or-less monotonic decline in production as a proportion of reserves is largely a reflection of the large increase in proven reserves as a result of the Montney potential in the context of technological advances in horizontal drilling and hydraulic fracturing.

Table 1: BC natural gas reserves, production, and consumption (millions of cubic meters)

Year	Reserves	Production	Consumption
2000	294,800	25,517	8466
2001	306,526	29,072	8406
2002	310,064	31,446	7376
2003	326,928	29,653	6960
2004	389,738	31,261	7096
2005	444,592	31,847	7013
2006	462,425	35,411	6722
2007	482,927	31,933	7495
2008	605,280	33,467	7192
2009	657,881	32,930	6906
2010	931,971	34,992	6169
2011	974,876	41,441	6361
2012	1,138,474	40,982	6332
2013	1,197,229	44,567	6155
2014	n.a.	47,214	6130

Notes: Reserves at end of year. Consumption includes Northwest Territories and Yukon. Cubic feet equals cubic meters times 35.3. "n.a." = not available.

Sources: BC Oil and Gas Commission, 2013; Canadian Association of Petroleum Producers, 2015; <https://www.bcogc.ca/node/12346/download> (reserves); <http://statshbnew.capp.ca/SHB/Sheet.asp?SectionID=3&SheetID=181> and <http://statshbnew.capp.ca/SHB/Sheet.asp?SectionID=3&SheetID=326> (production); <http://statshbnew.capp.ca/SHB/Sheet.asp?SectionID=6&SheetID=221> (consumption).

Estimates of BC Natural Gas Reserves

Table 2 summarizes three recent estimates of natural gas resources in British Columbia. It is important to note the substantial variation in the definitions and magnitudes of "reserves." This uncertainty is another reason that the size and timing of investment decisions properly are the responsibility of the private sector, even if government agencies offer their estimates of the magnitude of the resource.

Table 2: Estimates of BC natural gas reserves (trillion cubic meters)

Source	Estimate	Definition
National Energy Board, et. al. (2013)	10.6	ultimate potential, marketable, 2012
BC Oil & Gas Commission (2013)	1.2	remaining established, 2013
US Energy Information Administration (2014)	9.5	shale technically recoverable, n.a.

The estimate in the first row was published by a federal-provincial consortium of Canadian agencies in a report on the gas reserves available in the Montney Formation, now vastly more economic to produce because of modern horizontal drilling and hydraulic fracturing technologies. The estimate is of BC's "ultimate potential" for "marketable" natural gas reserves as of the end of 2012 of 376 trillion cubic feet (10.6 trillion cubic meters) in total, including all gas resources both conventional and unconventional (National Energy Board et al., 2013: Table 4).[3] The BC Minister of Natural Gas Development, Rich Coleman, argued in the wake

3 The "ultimate potential" of the Montney formation itself is listed at 7.7 tcm, or 271 tcf.

of the study that "now, more than ever before, BC can supply energy needs at home and abroad. The Montney area will support economic activity in our province for a very long time as a supply hub for liquefied natural gas development."[4] Coleman is reported separately to have estimated that BC natural gas reserves would be sufficient for 150 years of exports into the international LNG market (CBC, 2013).

The second source is a report published by the BC Oil and Gas Commission (2013: Tables A1, A2), with an estimate of BC's "remaining established" gas reserves as of the end of 2013 of about 1.2 tcm, or about 42.4 tcf. The US Energy Information Administration estimate is for British Columbia's (and the Northwest Territories') technically recoverable shale gas re;sources: about 336 tcf, or about 9.5 tcm (EIA, 2014: Table I-1).[5] EIA notes as well that:

> Most of Canada's natural gas reserves are traditional resources in the WSCB, including those associated with the region's oil fields. … Vast deposits of unconventional natural gas reside in the WCSB in the form of coal bed methane (CBM), shale gas, and tight gas … Canada has an estimated 573 Tcf of technically recoverable shale gas resources, [of which f]ive large sedimentary basins in western Canada … account for 536 Tcf of the total of technically recoverable shale gas resources. (EIA, 2014)[6]

The International Market for BC LNG

BP forecasts an increase in global natural gas consumption from 3.6 tcm (125.9 tcf) in 2015 to 5.1 tcm (178.6 tcf) in 2035 (BP, 2015).[7] With respect to the LNG share of that market, the National Energy Board (2015a) has published an analysis of global demand and supply conditions for LNG through 2035. It projects an increase in global LNG consumption from about 40 bcf per day (1.1 bcm/d) in 2018 to 80 bcf/d (2.3 bcm/d) in 2035, an annual average compound growth rate of about 4.2 percent. The respective annual figures are 14.6 tcf (413.6 bcm) in 2018 and 29.2 tcf (827.2 bcm) in 2035.

The NEB analysis shows annual LNG export capacity globally of over 140 bcf/d (4.0 bcm/d) from 2020 through 2035, or about 52 tcf (1.5 tcm) on an annual basis. This future export capacity is notional in that it includes global capacity that is already operational, under construction, proposed and approved in Canada, proposed and pending in Canada, and proposed US projects not under construction. The two classes of Canadian projects total about 43 bcf/d, or 15.7 tcf (440 bcm) annually.

This NEB analysis does not include LNG expansion projects elsewhere in the world. A recent analysis published by the International Energy Agency provides a rough estimate of about 160 bcm per year of additional LNG export capacity to be installed globally between 2015 and 2020 (IEA, 2015: Fig. 4.16). By 2020, IEA estimates global LNG export capacity at 561 bcm (2015: Fig 4.17). We use IEA projections here because

4 Quoted in Canadian Energy Perspectives (2013).

5 EIA estimates overall Canadian technically recoverable shale gas resources at 573 trillion cubic feet. See also <**http://www.eia.gov/analysis/studies/worldshalegas/**> and <**http://www.eia.gov/beta/international/analysis.cfm?iso=CAN**>. To convert cubic feet to cubic meters, divide the former by 35.3.

6 The WCSB is the Western Canadian Sedimentary Basin. A map of the British Columbia part of the WCSB is provided by the British Columbia Oil and Gas Commission at <**https://www.bcogc.ca/node/8254/download**>.

7 Million tons oil equivalent converted to billions of cubic meters of natural gas at a conversion rate of 1.11.

it is an international agency established in 1974, well known, using analytic methodology that is open to review and scrutiny, and without an obvious interest in the issues attendant upon the British Columbia LNG export market.

IEA (2015: Fig. 4.18) projects that by 2020, the four largest LNG exporters in descending order will be Australia, Qatar, the US, and Indonesia, with respective annual export levels of approximately 120 bcm, 100 bcm, 80 bcm, and 50 bcm. IEA notes also that as of May 2015, ten BC LNG projects with a combined production capacity of about 185.5 bcm per year had received NEB approval (2015: Table 4.3).[8] For these projects, the targeted online dates are between 2016 and 2021. (In addition, the Jordan Cove and Oregon LNG projects in the US have received NEB approvals for their Canadian operations.)

These projections imply that the ten BC projects combined would be the largest among the five exporters, with a third of the total export capacity. At the same time, IEA notes that "[n]o Canadian LNG project will start production over the forecast horizon of this report [that is, by 2020]. … Before construction can start, all projects still require approval from the federal government and other provincial authorities as well as First Nations" (2015: 115), and also that:

> Despite their proximity to Asian markets, Canada's LNG projects are at a disadvantage to United States projects. US projects under construction today are all brown-field facilities, resulting in much lower capital costs per unit of capacity, as operators can leverage existing regasification infrastructure. By contrast, all but one of the proposed Canadian plants are greenfield units. Additionally, they also follow the traditional integrated upstream model whereby the LNG plant and the connected upstream asset are developed in an integrated fashion. This adds to the project's upfront costs and, for Canada, specifically dedicated pipelines must be built to connect LNG plants on the coast with inland gas fields in remote areas. (IEA, 2015: 115)

This qualitative cost analysis from the IEA is problematic, in that the brownfield/greenfield distinction conflates accounting costs with true economic (opportunity) costs; and neither integration of upstream and downstream assets nor the need to build dedicated pipelines increases costs, as the use of non-dedicated pipelines would increase the demand for their services, and thus the market prices that they can charge. But the larger point remains valid: the prospective LNG market promises to be highly competitive, and delay in acquisition of the needed government approvals cannot be advantageous.

Of particular interest in this context is the prospective demand for LNG in the Asia-Pacific region. The BP projections for natural gas consumption and production in that region are summarized in **table 3**.

8 The US Federal Energy Regulatory Commission lists eleven potential BC projects as of June 2015, with a combined capacity of 247 bcm per year. See <**http://www.ferc.gov/industries/gas/indus-act/lng/lng-export-potential.pdf**>.

Table 3: BP Projections, Asia-Pacific natural gas consumption and production (bcm)

Year	Production	Consumption	Difference
2015	744	567.3	176.7
2020	941.5	689.2	252.3
2025	1072.8	693.6	379.2
2030	1168.9	729.2	439.7
2035	1267.5	841.4	426.1

Note: BP defines the Asia-Pacific region as "Brunei, Cambodia, China, China Hong Kong Special Administrative Region, Indonesia, Japan, Laos, Macau, Malaysia, Mongolia, North Korea, Philippines, Singapore, South Asia (Afghanistan, Bangladesh, India, Myanmar, Nepal, Pakistan and Sri Lanka), South Korea, Taiwan, Thailand, Vietnam, Australia, New Zealand, Papua New Guinea and Oceania."

Source: BP, 2015.

The BC projects already approved by the NEB (as of May 2015) would be in a position to supply a very large part of the prospective Asia-Pacific market for LNG.[9] Recall from above the IEA projection that the four largest LNG exporters in descending order in 2020 will be Australia, Qatar, the US, and Indonesia, with respective export levels of approximately 120 bcm, 100 bcm, 80 bcm, and 50 bcm. IEA lists seventeen international projects under construction as of May 2015, with combined capacity of about 175 bcm per year, and with target online dates between 2015 and 2019 (IEA 2015: 112).

Recall also that the approved BC projects total 185.5 bcm in annual capacity; accordingly, under the rough assumptions suggested by the IEA and NEB analyses, BC's export potential would make it the largest LNG exporter in the medium term and at a minimum an important competitor in the Asia-Pacific market.

Like BC, all of the four other major producers have more-or-less direct transport proximity to buyers in the Asian-Pacific region, and thus will be able to compete with BC LNG for sales there. Obviously, not all LNG exports from these exporters will go to those buyers; Europe, Africa, South America and buyers in other regions will compete for these supplies. But it is clear from the projections—which should not be viewed as strictly accurate, as no forecasts can be, but instead as general unbiased order-of-magnitude parameters—that unnecessary delay in development of the BC LNG export sector will result in significant forgone opportunities.

Strictly speaking, revenues may not be the correct measure of the economic cost of delay: revenues above the social cost of producing the LNG are that economic cost. But most of the cost of producing LNG is the capital cost of the facilities. Construction delays yield cost savings equal only to the interest on the construction costs, while the revenues lost in a given year due to such delays are lost forever unless the sales are simply shifted back in time. That may or not be the case in a market in which long-term contracting is the dominant form of sales arrangements; but in any event, we define delay costs carefully below as annual export revenues forgone as a result of delays.

Let us construct a conservative scenario for the export revenues to be lost due to delay in regulatory approval for the needed capital facilities. If we consider only the BC LNG projects that already have received NEB approval, then that combined export capacity would be about 185 bcm per year. That could satisfy 74 percent, 49 percent, 42 percent, and 44 percent of Asia-Pacific demand for LNG imports in 2020, 2025, 2030, and 2035, respectively (table 3). Let us assume, conservatively, that the BC share of the Asia-Pacific export market would be 50 bcm

9 See NEB (2015b) for the full list, documentation, and other information.

per year.[10] That would be only 11–20 percent of that market over the 2020–2035 period.

We must ask next what future natural gas prices would be reasonable to assume for exports into that market. **Table 4** shows IMF and World Bank forecasts for natural gas prices in the US and Japan for 2020.

Table 4: IMF and World Bank natural gas price forecasts, 2020 (2014 US$ per million BTUs)

IMF		World Bank	
US	*Japan*	*US*	*Japan*
3.10	11.25	4.18	12.43

Sources: IMF: <http://knoema.com/IMFCPF2015Jun/imf-commodity-price-forecasts-june-2015>; World Bank: <http://knoema.com/WBCFPD2015Jun/world-bank-commodity-forecast-price-data-june-2015>; author computations.

The US EIA forecasts US natural gas prices (spot prices at Henry Hub, in inflation-adjusted US dollars) at about $5.00 in 2020, rising to $5.50 in 2025, $5.95 in 2030, and $6.50 in 2035 (EIA, 2015: Figure ES2).[11] The IMF and World Bank forecasts are for 2020 prices in Japan very roughly three times higher than US spot prices (table 4). That multiple is lower than those from 2013 and 2014, roughly 4.5 and 3.55, respectively.[12] This decline in the US/Japan price multiple is the result of several factors, among them changes in market conditions both internationally and in Japan, oil prices, exchange rates, and a number of others. But an obvious one is the increase in international export capacity for LNG. The IEA data suggest that LNG exports of 50 bcm from BC to Japan would reduce the Japan/US price multiple very roughly from 3.0 to 2.0 (IEA, 2015: 112–113, figures 4.16 and 4.17). Because prices across markets cannot diverge by more than differential transport costs and other minor factors—there can be only one market price for natural gas as the market becomes more international in character—that multiple remains reasonable for analytic purposes. **Table 5** summarizes these calculations.

Table 5: Notional BC LNG export revenues (2014 US$)

Year	Exports per mm btu	Assumed US price	Asia-Pacific price	Export revenues
2020	50 bcm	5	10	17.6 billion
2025	50 bcm	5.5	11	19.4 billion
2030	50 bcm	5.95	11.9	21.0 billion
2035	50 bcm	6.5	13	22.9 billion

Note: One million btu is equal to about 1000 cubic feet. Fifty bcm equals 1.765 trillion cubic feet.

Source: Author computations.

10 A slightly dated NEB analysis projects total Canadian natural gas exports at about 36.5 bcm in 2020, under a "high price" assumption, one that is relevant for this conceptual experiment, in that Asia-Pacific prices for natural gas are certain to exceed US/Canada prices by a substantial amount, as discussed below (NEB, 2013: Figure 6.5). Note that British Columbia gas resources always can be exported into the North American market, but the market for BC natural gas transformed into LNG is certain to be located outside North America. Moreover, as suggested in table 4, those external prices are very likely to exceed prices inside North America even adjusting for higher transport costs. Another point to be made is that gas produced in other provinces or territories but exported from BC provides some value to the BC economy, but the analysis reported here is focused on the cost of infrastructure delay for BC natural gas resources, of which those in the Montney formation are the most recent major addition.

11 These numbers are for the EIA reference case.

12 Author computation of the average IMF and World Bank price multiples. See the sources listed in table 4.

Accordingly, a rough estimate of the revenue losses from regulatory delays imposed upon the BC LNG export market would be on the order of $17–23 billion (US) per year of lost exports, or $17.6 billion in 2020. At a US/CA dollar exchange rate of about 1.277, the lost revenues as of 2020 would be approximately CA$22.5 billion.[13] BC GDP in 2014 was about CA$235.7 billion.[14] Accordingly, the lost export revenues in 2020 would have equated to 9.5 percent of provincial GDP in 2014, a very substantial impact.

It is conservative to assume that BC would capture only 11–20 percent of the Asia-Pacific market for LNG, even with export capacity equal to 42–74 percent of that market. If we cut assumed British Columbia exports in half to 25 bcm per year, as a further concession to conservatism in our assumptions, lost revenues in 2020 would be over CA$11 billion, equating to almost 5 percent of provincial GDP in 2014. If we assume *in addition* Asia-Pacific prices only half those shown in table 5, lost export revenues would be about CA$5.5 billion, over 2 percent of provincial GDP in 2014. Even that figure, based upon exceedingly conservative assumptions, is not trivial.

Conclusion

As noted above, the IEA believes that "[n]o Canadian LNG project will start production" by 2020, even as 17 international projects are under construction as of May 2015, with combined capacity of about 175 bcm per year, and with target online dates between 2015 and 2019 (IEA, 2015: 112, Table 4.2). As ten of those projects are American or Australian, it is not plausible that it is insufficient environmental standards that have allowed those projects to move ahead of the BC proposals. This suggests that the differential delays afflicting the latter are likely to be excessive.

After noting the competitive disadvantages affecting BC LNG projects due in substantial part to regulatory delays, the IEA points out that:

> Lack of progress amid deteriorating market conditions has prompted the Canadian government to make concessions on the taxation front. In February 2014, the government of British Columbia proposed provincial LNG taxation which was heavily criticised for placing too much of a burden on the industry and thus undermining the competitiveness of West Coast projects. Fiscal terms were ultimately sweetened in the final version of the proposal unveiled in October 2014. Amid falling oil prices, the Canadian Federal government pushed through further investment-friendly policies in February 2015, agreeing to grant tax breaks to British Columbia projects and thus allowing LNG investors to recover capital costs more quickly. (IEA, 2015: 116)

That brief history of the evolution of the LNG tax issue in BC demonstrates a recognition of the obvious: private investment depends on private returns, and government tax policies matter in terms of investment incentives.[15] The

13 Exchange rate as of July 8, 2015, from <**http://www.x-rates.com/**>.

14 See BCStats, *British Columbia's Key Indicators*, at <**http://www.bcstats.gov.bc.ca/StatisticsBySubject/KeyIndicators/KeyIndicatorsHighlights.aspx**> and <**http://www.bcstats.gov.bc.ca/StatisticsBySubject/Economy/EconomicAccounts.aspx**>.

15 This obvious truth is separate from the level and structure of taxes that would be economically efficient in the LNG context. That depends on the relationship between the demand for LNG investment and the demand for provincial public services, a topic outside the scope of this discussion. A separate issue is the effect of prospective revenues on incentives to expedite regulatory approvals, also a subject not addressed here.

same should be true for regulatory and other policies, with a central caveat: it is more difficult to estimate the costs attendant upon various regulations and regulatory delay.

This study examined the cost of regulatory delay imposed upon LNG investments in BC, defined as export revenues forgone. That cost is substantial: CA$22.5 billion in 2020, rising to CA$24.8 billion in 2025. The export revenues lost in 2020 would be equal to 9.5 percent of British Columbia GDP in 2014, under a set of conservative assumptions the most important of which is that BC's export capacity would be 42–74 percent of the Asia-Pacific market, but actual sales would be only 11–20 percent of that market. If we cut assumed sales in half, lost revenues would approach 5 percent of GDP; if we *also* cut assumed prices in half, lost revenues still would be over 2 percent of GDP. The magnitudes of these prospective losses are substantial, a reality that should encourage policymakers to streamline the regulatory process so that British Columbia can make use of its large natural gas resources and exploit its comparative advantages in the LNG export market.

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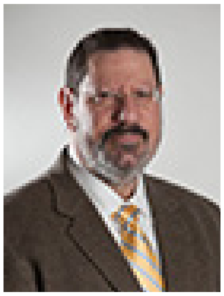

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