FUELING CHANGE

UPSTREAM IMPLICATIONS OF THE B.C. LNG SECTOR

Extended Summary Report of:

- Phase 1: Identifying B.C. LNG Export-Induced Natural Gas Extraction Scenarios for FNFN Territory
- Phase 2: Effects of LNG-induced Gas Extraction on FNFN Territory

May 2014

Authored by Alistair MacDonald,
The Firelight Group Research Cooperative

Commissioned by Fort Nelson First Nation

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ACKNOWLEDGEMENTS

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EXTENDED SUMMARY REPORT

An Overview of This B.C. LNG Demand and Implications Study

Each [B.C. LNG export] proposal would see a dramatic increase in fracking in the northeastern region of B.C. — Crist (2013, 10)

British Columbia is laying the groundwork for a massive increase in unconventional gas production, mostly coming from the northeast of the province.

WHAT IS GOING ON WITH NATURAL GAS PRODUCTION IN B.C.? British Columbia is laying the groundwork for a massive increase in unconventional[1] gas production, mostly coming from the northeast of the province. In an effort to get a piece of the growing global market for liquefied natural gas (LNG), B.C. and Canada have been entertaining development proposals to establish natural gas pipelines and LNG export facilities on B.C.'s northwest coast. Right now, there are 10 proposed LNG export facilities that would rely on Canadian gas. Each proposed LNG facility and associated pipeline requires a secure stock of natural gas to be viable. Even conservative estimates of LNG quantities needed to sustain these export facilities would result in a significant increase in "upstream activities," almost all of it related to hydraulic fracturing, or "fracking," of shale and tight gas deposits.

WHERE WILL ALL OF THIS NATURAL GAS COME FROM? The answer is the Western Canada Sedimentary Basin (WCSB). The WCSB contains some 90 per cent of Canada's natural gas reserves and produces 98 per cent of Canadian gas, the majority of it from Alberta and, increasingly, B.C. Current natural gas production in Canada is somewhere between 13 and 14 Bcf/day.

HOW WILL THIS IMPACT FORT NELSON FIRST NATION (FNFN)? FNFN is a traditional hunting/gathering society of 890 band members. FNFN territory includes some of the largest natural gas reserves in the WCSB and some of the most highly prospective shale gas resources in the world. FNFN shale basins include the Horn River Basin, the Cordova Embayment, and the Liard Basin. The B.C. government intends to facilitate the development of these reserves as feedstock for the LNG export sector, as described in its *LNG*

1 The term "unconventional" encompasses gas resources previously considered difficult to economically extract such as shale and tight sands deposits and coalbed methane.

Strategy (B.C. Ministry of Energy and Mines 2013). FNFN has raised concerns LNG would add significantly to already substantial gas sector effects on FNFN territory.

WHAT IS THIS STUDY ABOUT? Though the B.C. government has studied and marketed the economic benefits of LNG,[2] it has done little to assess or communicate the environmental implications. This study is the first attempt to look at potential effects on the air, water, land, wildlife and Aboriginal people of B.C. LNG export scenarios. It does this by estimating a range of potential gas extraction scenarios from FNFN territory to feed the B.C. LNG export sector over its first 20 years, and then estimating some of the potential effects (physical and otherwise) of these different LNG-induced gas extraction scenarios. The scenarios developed are the first dedicated effort to publicly identify these upstream implications in specific First Nations territories.

WHAT ARE THE FINDINGS? This overview summarizes the findings of two reports that were commissioned by FNFN and completed by Alistair MacDonald of The Firelight Group Research Cooperative.

Phase 1 develops a range of realistic scenarios of how much natural gas will be extracted from FNFN territory to feed B.C. LNG exports. It finds:

1. B.C. LNG exports will average between 37.5 and 82 million tonnes per annum (mtpa), starting about 2018, and lasting over an initial 20 year period. This is equivalent to between 4.9 and 10.7 billion cubic feet per day (Bcf/day) of natural gas feedstock.
2. Between 10 and 25 per cent of the gas for B.C. export facilities will come from FNFN territory.
3. Combining the two findings above, development of a B.C. LNG export sector will induce between 490 million and 2.68 billion cubic feet per day in gas extraction from shale gas basins in FNFN territory.

Each of the scenarios within this range would see significant increases in the amount of gas produced from FNFN territory above historic and current numbers. The lowest LNG demand scenario in FNFN territory would be 160 per cent more than 2012 gas production levels from FNFN territory of 0.28 Bcf/day. At the high end of the scenarios, that number jumps to an almost 10-fold difference.

Phase 2 uses the Phase 1 development scenarios to examine the amount of industrial development required to support this LNG-induced gas extraction and then identifies associated environmental effects on FNFN territory, including impacts to land, water, air, wildlife, and FNFN members. It finds that LNG-driven shale gas extraction of between 0.49 and 2.68 Bcf/day would result in the following changes in the three FNFN territory shale basins during the first 20 years of the sector:

- Between 356 and 3,995 new hydraulically fractured shale gas wells;

Though the B.C. government has studied and marketed the economic benefits of LNG, it has done little to assess or communicate the environmental implications. This study is the first attempt to look at potential effects on the air, water, land, wildlife and Aboriginal people of B.C. LNG export scenarios.

2 The B.C. government has made very public efforts to estimate, based on different scenarios of 82 to 120 million tonnes per year of LNG exports, what the economic benefits might look like for British Columbia. See for example studies by Ernst and Young (2013b); Grant Thornton (2013a; 2013b).

- Development of between 30 and 333 new large industrial facilities in the form of multi-well pad complexes, each covering an average area of nine hectares;
- Between 1,440 and almost 16,000 km of new seismic lines;
- Between 150 and 1,665 km of new roads;
- Development of between 135 and as much as 3,333 km of new pipeline ROW;
- Generation of a total of between 1,635 and 20,900 km of new linear disturbance;
- Generation of total direct areal disturbance of between 30 and 375 km^2, along with a total Zone of Influence of between 104 and 1,277 km^2;
- Between one and five additional large 600 Mmcf/day sales gas plants;
- Additional GHG emissions of between 2.6 and 15.1 million tonnes per year, creating substantial challenges to B.C. meeting its legislated emissions targets;
- Water usage in the hydraulic fracturing process alone of between 11 and 320 billion litres of water (between 31 and 80 million litres per well);
- Use of 1.4 to 16 million tonnes of frac sands, and mining of a substantial amount of it from FNFN territory; and
- Use of 55 million to 1.6 billion litres of chemical additives in hydraulic fracturing processes; and
- Clearing for and construction of hundreds to thousands of other physical works to support the gas sector.

This is an extended summary report only. The full reports for each phase contain details of the methods used for the analyses presented in this summary, and a full list of reference documents.

This scenario analysis clearly indicates that LNG would have a strong impact on the amount of upstream gas production activity in the shale basins of FNFN territory, and attendant environmental impacts associated with these physical works and activities. Even the low range estimate would see substantial growth in the amount of land fragmented, industrial infrastructure and activities occurring, water used, and GHG emissions released in FNFN territory.

WHAT ARE THE RECOMMENDED NEXT STEPS? This study is only a first step in the task of estimating upstream impacts of LNG in B.C. The findings indicate it is important to conduct more detailed work on scenarios linking upstream gas activities in northeast B.C. to the fledgling B.C. LNG export sector. Additional recommendations are provided at the end of this document and in the full Phase 2 report.

NEED MORE INFORMATION ON THE STUDY? This is an extended summary report only. The full reports for each phase contain details of the methods used for the analyses presented in this summary, and a full list of reference documents. Both are available at www.thefirelightgroup.com and www.fortnelsonfirstnation.org

PHASE 1

Phase 1: Identifying B.C. LNG Export-Induced Natural Gas Extraction Scenarios for FNFN Territory

WHAT IS LNG AND HOW IS IT PRODUCED?

WHAT IS LNG? Liquefied natural gas, or LNG, is a liquid form of natural gas that allows for transportation of the fuel across long distances. It is produced by super-cooling methane to -162°C, which causes the gas to liquefy to 1/600th of its normal volume. Specially designed massive double-hulled LNG ships are then used to transport LNG overseas to regasification systems.[3] With the growth of LNG transportation, the gas market is transitioning from regional to global. LNG trade represented around nine per cent of global gas demand in 2012.

WHAT IS UNCONVENTIONAL GAS? Unconventional gas refers to natural gas deposits that are trapped in shale, sandstone or carbonates, making them traditionally difficult to extract. The development of hydraulic fracturing (fracking) technology has changed the accessibility of these deposits (see next page for an overview of fracking technology). Unconventional gas is predicted to account for nearly half the growth in global gas production by 2035 (IEA 2012b), growing to 35 per cent of total natural gas production from 14 per cent in 2010.

Unconventional gas is predicted to account for nearly half the growth in global gas production by 2035 (IEA 2012b), growing to 35 per cent of total natural gas production from 14 per cent in 2010.

A BRIEF OVERVIEW OF THE GLOBAL LNG MARKET: The development of LNG and fracking technology are game changers for the global energy sector. The global LNG market has grown significantly over the last decade, and is predicted to increase by more than 50 per cent between 2012 and 2020.

3 The largest LNG carrier, called Q-Max, can transport 264,000 m^3 of LNG, or around 5.5 Bcf of gas. To put this in context, in 2012 B.C. produced approximately 3.5 Bcf of sales gas per day, which would not fill even one of these Q-Max tankers.

How Hydraulic fracturing works

The process of hydraulic fracturing (fracking) is required to recover certain kinds of gas deposits, like shale and tight sands. In FNFN territory, the deposits are largely held in shale, a non-porous and fine-grained sedimentary rock (B.C. OGC, 2010). The fracking process is illustrated in the figure below. To access gas reserves in these shale formations, several steps are taken:

- A horizontal well must be drilled. A horizontal well increases the length of contact with the shale gas formation over that of a conventional vertical well.
- A liquid mixture is injected to create pressure and induce stress in the rock ("stimulate") and create fissures and cracks. These cracks increase the permeability of the formation to increase the flow rate of gas into the well. The liquid is composed largely of water and sand, but chemical modifiers are added to facilitate fracturing (Gregory et al., 2011). These chemicals may include gels, foam, hydrochloric acid, biocides, or other fluids (King, 2013). In addition to high water requirements, each fracked well may require up to 4,000 tons of proppants, and up to 200,000 litres of chemicals (International Energy Agency 2013).
- After the fracturing activity, the pressure is decreased and gas flows from fissures into the well. Increasingly, multiple wells from a single well pad and multiple fractures per well are being used in FNFN territory.

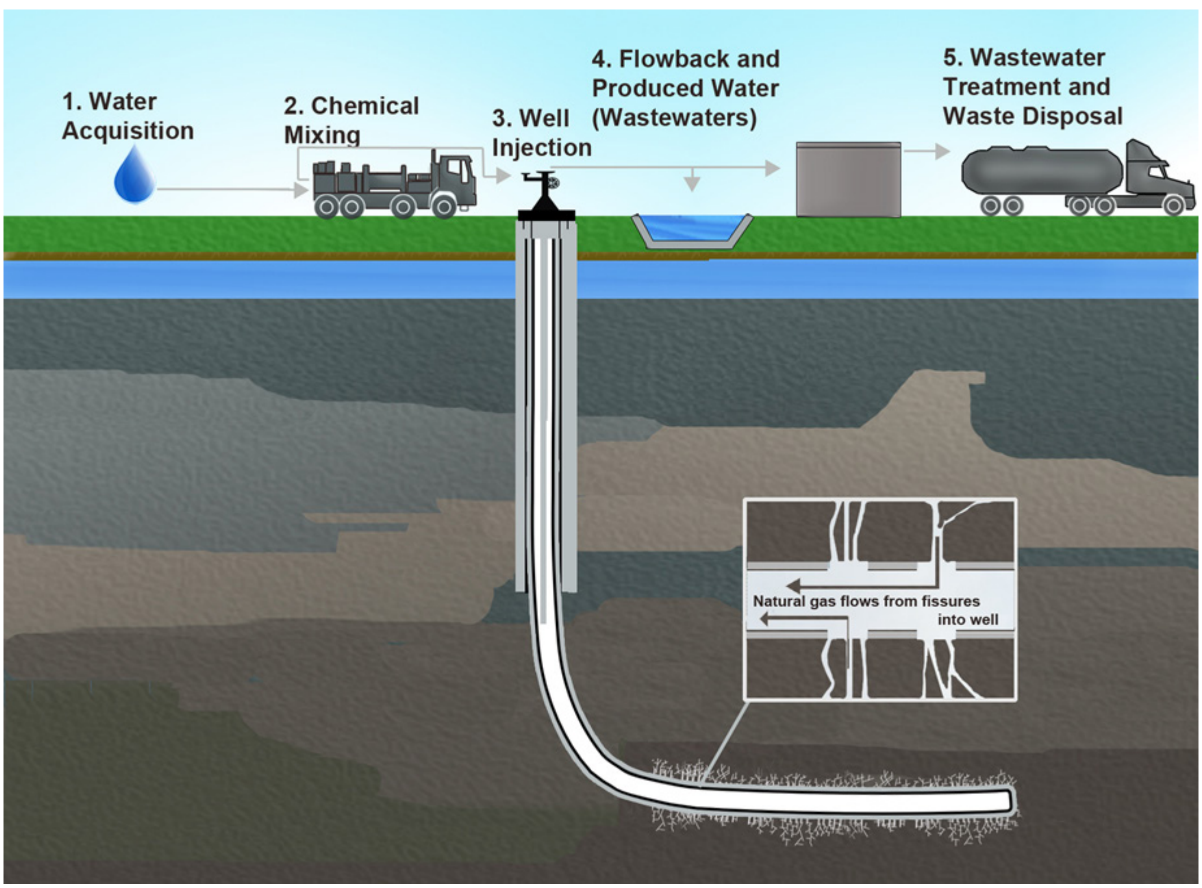

Image source: Fross and Lyle (2013)

How to measure supply?

Natural gas is typically measured in terms of volume: either in millions, billions or trillions of cubic feet (Mmcf, Bcf, Tcf) or cubic metres (Mmcm or BCm). The following calculation can be used to convert between the two:

1 cubic metre = 35.3 cubic feet

LNG, however, is typically measured in millions (metric) tonnes per annum (mtpa). The following conversion factors can be used to convert between LNG and natural gas, as per Ernst and Young (2013a):

1 million tonnes of LNG = 1.36 B.C.m of natural gas or about 48 Bcf of natural gas.

The International Gas Union (2011, 4) predicted that "demand for LNG for the next five years is expected to remain strong." This increase in demand is fueled partly by the perception that natural gas is a "cleaner" energy source than conventional oil, and partly by a variety of other factors (e.g., the tsunami and subsequent nuclear crisis in Japan).

WHAT DOES THIS MEAN FOR THE NORTH AMERICAN LNG MARKET? Currently, all of the natural gas produced in Canada is destined for the domestic and U.S. markets. But with rising Asian LNG demand and newly economic unconventional gas extraction technologies (horizontal drilling and hydraulic fracturing), western Canada is thought to have high potential to be a global supplier of LNG. Shale gas resources account for more than half of the Canada's gas reserves and have been identified as a significant factor in increasing the country's competitive advantage in energy markets on a global scale (Government of Canada, 2013). Production levels for tight and shale gas have more than doubled in a little over a decade (NEB, 2013a). The National Energy Board (NEB) (2013b) reports that there has been a "major increase in estimates of Canada's tight and shale gas resources"; and that 92 per cent of gas produced in Canada by 2035 will be tight and shale gas.

AN OVERVIEW OF THE WCSB AND FNFN TERRITORY UNCONVENTIONAL GAS BASINS

> *"British Columbia's Montney play in particular is one of the best shale plays in North America, while the Horn River Basin is also more competitive than conventional natural gas plays" (OnPoint Consulting 2010, 10).*

WHAT ARE THE MAJOR UNCONVENTIONAL GAS RESERVES IN THE WCSB? Within the Western Canada Sedimentary Basin (WCSB), major unconventional reserves include the Montney Basin and the Horn River Basin, where in combination over 1,400 wells are producing over 2 Bcf/day of gas.[4] Other potentially important shale gas reserves that are largely undeveloped in the WCSB include the Liard Basin and Cordova Embayment in B.C., as well as the Duvernay formation in Alberta. Shale and tight gas basins in the WCSB are extremely large, on par with other major unconventional resources around the world.

As shown in Figure 1, FNFN's core territory[5] covers the entire B.C. boundaries of three natural gas basins — the Liard Basin, the Horn River Basin, and the Cordova Embayment. The Horn River Basin has seen the bulk of exploration, development and production activity to date, but all three are highly prospective and immature gas basins, meaning their extensive gas resources remain almost completely intact. Altogether, these gas basins cover nearly half of FNFN core traditional territory.[6] With the possible exception of Cordova Embayment, each FNFN territory shale basin alone likely has enough gas in place to fuel B.C.'s LNG export requirements for decades.

ESTIMATING LNG-INDUCED GAS EXTRACTION FROM FNFN TERRITORY

WHAT METHODS WERE USED TO ESTIMATE HOW MUCH GAS WILL COME FROM FNFN TERRITORY TO FUEL THE B.C. LNG SECTOR? Given Asian demand for LNG and the B.C. government's determination to capitalize on the vast unconventional gas reserves that underlay FNFN territory — much of it already under tenure to various companies — it seems likely that LNG will induce additional natural gas development within FNFN territory. Questions remain: How much LNG export capacity will be developed, and how much will come from FNFN territory? Phase 1 of this study used three steps to identify a range of reasonable estimates of how much natural gas is likely to be extracted from FNFN territory over the first 20 years of a B.C. LNG export sector.

STEP 1: *Identify a range of high and low B.C. LNG export scenarios.* To identify potential B.C. LNG export scenarios, the study used information from a wide range of secondary data sources, including government estimates, facility proposals to date, and estimates from industry analysts. These estimates help define how much natural gas must be extracted to fuel the B.C. LNG export sector.

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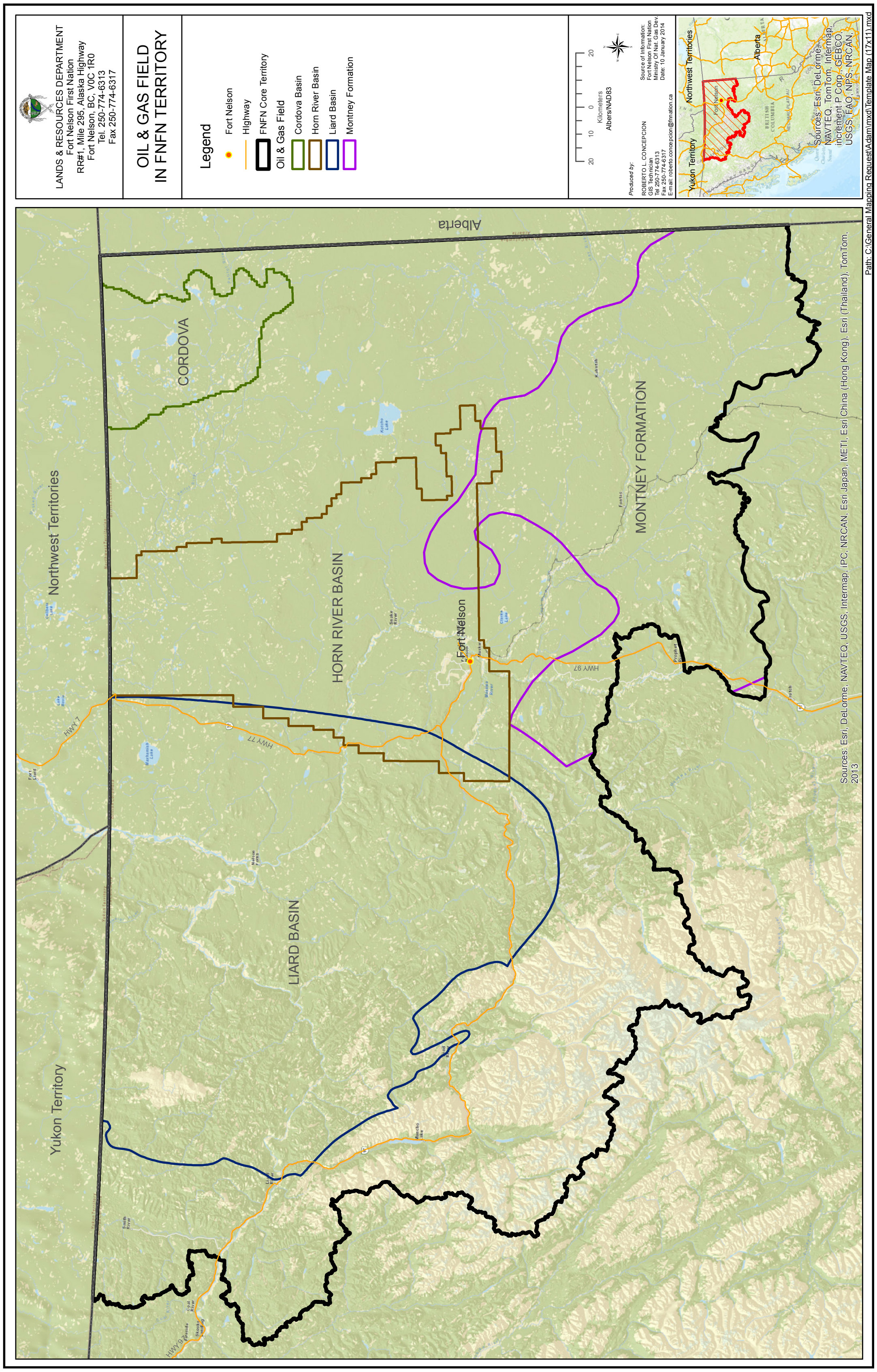
4 As of November 2012, based on B.C. OGC data.

5 FNFN defines its core territory as mapped in Figure 1, showing the areas most often used by FNFN in its traditional territory.

6 Horn River and Liard Basins and the Cordova Embayment cover 36,690 km^2, 45.8 per cent of the total FNFN core territory. The northern erosional edge of the Montney Formation is also in FNFN territory, but was not considered in this study.

Figure 1: FNFN core traditional territory, showing major shale gas basins



STEP 2: *Identify a range of proportions of how much B.C. LNG-induced gas will come from FNFN territory.* This step uses a variety of factors to triangulate the potential proportion of gas required to fuel B.C.'s LNG demand that would come from the three shale gas basins (Horn River, Liard and Cordova Embayment) located within FNFN territory.

STEP 3: *Develop a range of LNG-induced gas demand scenarios for FNFN territory*, based on a matrix combining the results of scenarios from steps 1 and 2. A 20-year time span (2018–2038) has been chosen as the boundary for analysis.

Limitations of the Phase 1 study include:

- The pace of change in the gas sector has been and will likely continue to be rapid. The whole picture can change quickly, making it difficult to confidently estimate future activity levels and location. For example, within a couple of years in the late 2000s, technological change toward unconventional gas sources increased resources several fold in the North American gas market. The future is equally uncertain.
- Secondary data are relied upon exclusively to develop the range of potential outcomes for each set of scenarios. The data from secondary sources, including predictions by government agencies and industry analysts, are adequate to predict a range of B.C. LNG export production levels moving forward. However, they cannot be used to estimate what number is most likely.
- Similarly, it is impossible to predict with absolute certainty what proportion of the gas will be extracted from FNFN territory and its three primary gas basins based solely on available public information. The best information about key factors that will have a major impact on production in FNFN lands (e.g. comparative potential production costs by basin) are largely not in the realm of freely available public information and thus beyond this study's scope to examine.

STEP 1: HOW MUCH LNG WILL BE EXPORTED FROM B.C. IN THE NEXT 20 YEARS?

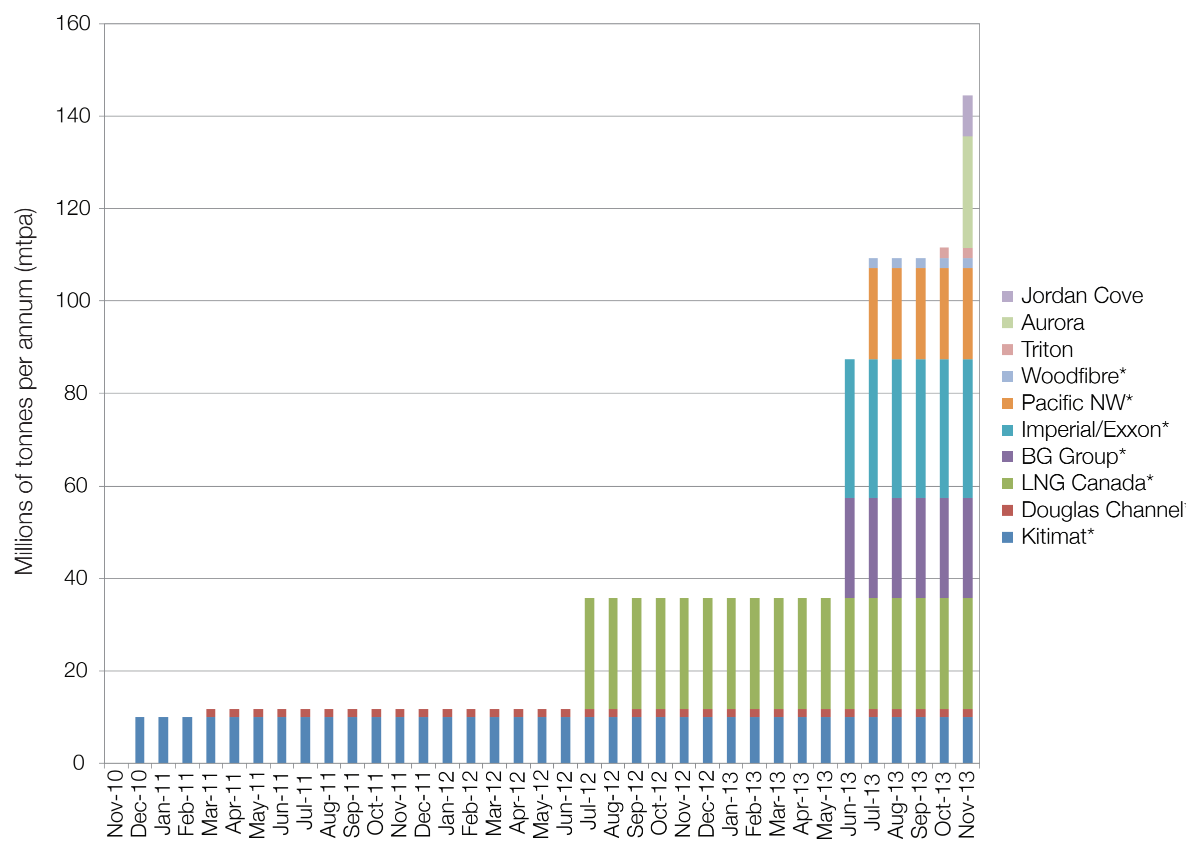
IT IS CRITICAL FIRST TO ESTABLISH A REALISTIC RANGE OF B.C. LNG EXPORTS. Phase 1 used three main types of data to triangulate how much B.C. LNG export capacity is likely to be developed. The inputs for the analysis include:

- B.C. government estimates and forecasts;
- Industry proposals to date for LNG facilities and associated pipelines; and
- Industry analyst estimates of potential B.C. LNG export sector growth.

WHAT DOES THE B.C. GOVERNMENT SAY? Based on studies commissioned by the Province (Grant Thornton 2013a; 2013b; Ernst and Young 2013b), the B.C. government has modeled an LNG market ranging from 82-120 mtpa between 2019 and 2038. This would require the equivalent of 10.7 to 15.7 Bcf/day of natural gas for B.C. LNG facilities, not counting energy requirements and process losses. At this time, these numbers appear unrealistically high (Petroleum News 2013; Pembina Institute 2013; Mirski and Coad 2013). However, the Province's reference to these scenarios requires that they be considered in this analysis.

HOW MUCH NATURAL GAS WOULD BE REQUIRED TO SUPPORT ALL PROPOSED LNG FACILITIES? As of November 2013, the B.C. government officially recognized ten proposed LNG facilities in various stages of the project planning process, with a combined LNG export capacity of 144.8 mtpa equivalent or approximately 18.9 Bcf/day[7]. This is above even the aggressive range (82–120 mtpa) used by the B.C. government in its economic benefits estimations. While most industry experts agree that this amount of LNG export development is unlikely, by the end of December 2013, over 105 mtpa of export licences had been issued by NEB (2013c), signaling regulatory if not yet market support for that amount of LNG export from the west coast of Canada. By issuing export licences for this level of LNG export, the NEB is signaling that it considers the Canadian gas production system, 98 per cent of which is within the WCSB, is robust enough to handle this effective doubling of the WCSB gas extraction sector over and above the existing 13–14 Bcf/day currently produced for the North American markets.

Figure 2: NEB export license applications, and licenses already granted,* as of December 2013



WHAT DO INDUSTRY ANALYSTS ESTIMATE? Several groups of very different backgrounds, including Ziff Energy Group, the Fraser Institute, and the Pembina Institute, have provided estimates of B.C. coastal LNG export potential. A variety of these estimates are listed in Table 1. There is a large grouping of analysts' estimates in the 4 to 8 Bcf/day range, roughly the LNG equivalent of 30 to 60 mtpa.

7 The full Phase 1 report provides further details about all currently proposed B.C. LNG export facilities and associated new gas pipelines.

Table 1: Industry and analyst B.C. LNG export scenarios	
Source	Potential B.C. LNG Export Gas Requirements
Antunes et al. (2012)	2.6 Bcf/day, with four trains staring in 2016, 2018, 2019, and 2021 respectively
Ziff Energy Group (2012)	8.7 Bcf/day by 2024
Fraser Institute (2012)	7.1 Bcf/day by 2032
Pembina Institute (2013)	Low: 3.13 Bcf/day; Medium: 5.26 Bcf/day; High: 9.25 Bcf/day (no date)
Walden (2013)	8 Bcf/day by 2030
Ziff Energy Group (2013a)	5.0 Bcf/day in 2050, starting in 2017
Ziff Energy Group (2013b)	4.9 Bcf/day starting in 2020
Ziff Energy Group (2013c)	7.6 Bcf/day in 2050

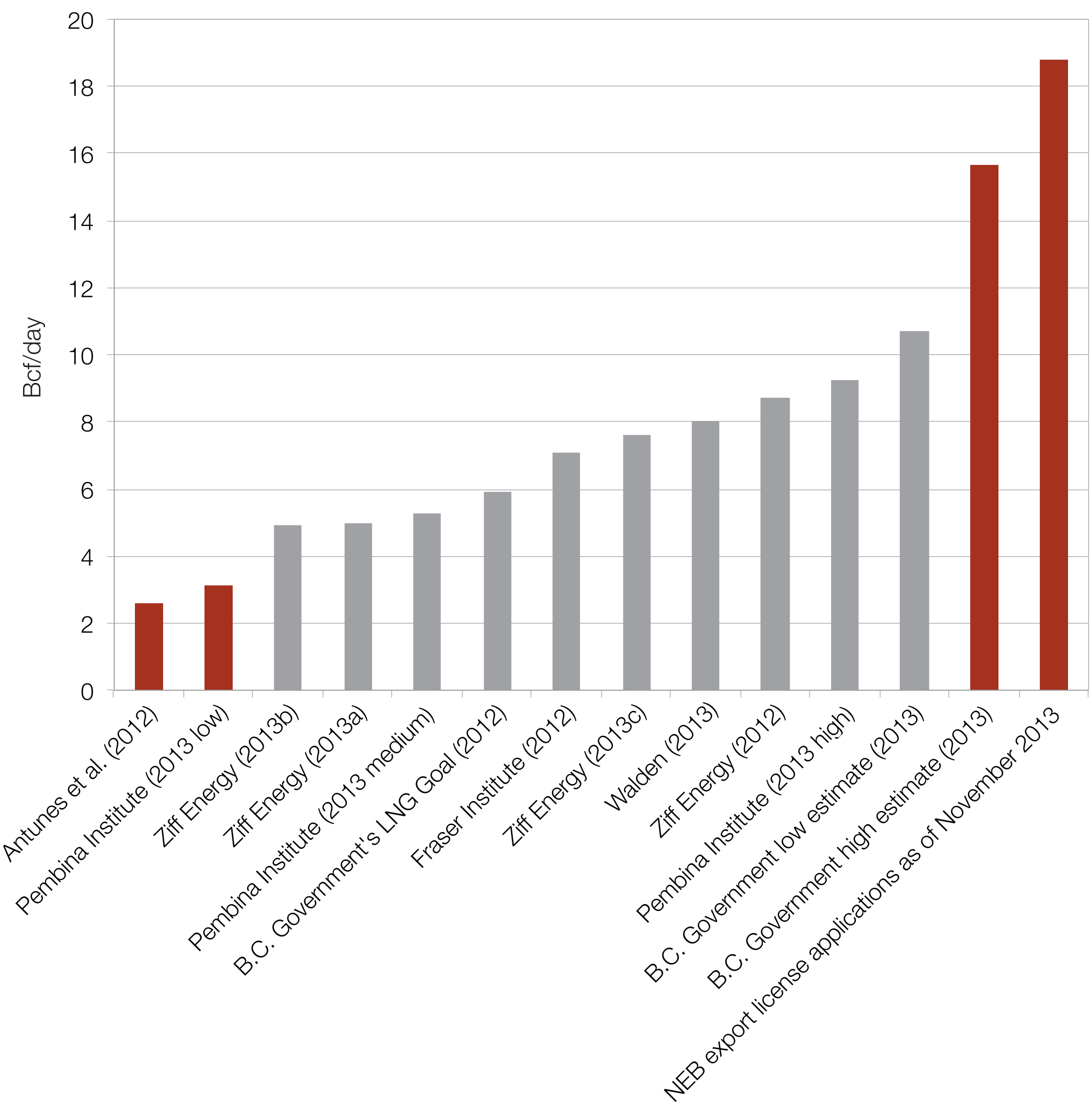
WHAT IS A REASONABLE RANGE FOR B.C.'S LNG EXPORTS? A range of potential B.C. LNG export capacity scenarios using the three triangulation tools is shown in blue in Figure 3.

In the author's opinion, the figures arising from industry analysts are a better estimate than those presented by the B.C. government. In addition, current proposals of more than 18 Bcf/day in NEB export licences, equivalent to over 140 mtpa, are unrealistic. The low end estimates in Figure 3 are also unconvincing, in light of current proposals for over seven and six times these amounts, respectively. Thus, the top two and bottom two estimates (in red in Figure 3) have been removed.

The results point to between 4.9 Bcf/day and 10.7 Bcf/day as a range of potential future growth scenarios for LNG exports from British Columbia between 2018 and 2038. This is equivalent to between 37.5 mtpa and 82 mtpa.

Most importantly: *change is clearly coming*. Ten LNG facilities have been proposed in the past two to three years that would rely on WCSB gas sources. In total, they are for LNG export capacity of more than 140 million tonnes per year. To put some context to this, this equals about 6.9 trillion cubic feet of natural gas per year, or over 18 billion cubic feet per day. In 2012, gas production from FNFN territory was less than 400 million cubic feet per day ($1/45^{th}$ of the total applied for LNG export licenses), and B.C. in total only produced about 3.5 billion cubic feet of sales gas per day ($1/5^{th}$ of the total proposed LNG export capacity). At least two of the proposed pipelines to liquefaction facilities could *by themselves* exceed this capacity. While nowhere near this much LNG capacity is likely to be developed, the high end of the reasonable range would still be equivalent to three times B.C.'s existing gas production and almost as much as current WCSB production.

Figure 3: B.C. LNG export scenario estimates (converted to Bcf/day)



STEP 2: HOW MUCH LNG GAS FEEDSTOCK WILL COME FROM FNFN TERRITORY?

HOW WAS THIS ESTIMATED? This analysis uses five methods to estimate what proportion of natural gas production used to fuel the B.C. LNG export sector will come from FNFN territory:

1. Current FNFN gas production as a proportion of current WCSB totals;
2. FNFN gas-in-place resources as a proportion of WCSB totals;
3. Industry, government and analysts' estimates of future basin-by-basin production;
4. Discussion of factors affecting basins' comparative gas supply advantages; and
5. Vertical linkages of current FNFN territory shale gas tenure holders to proposed LNG facilities.

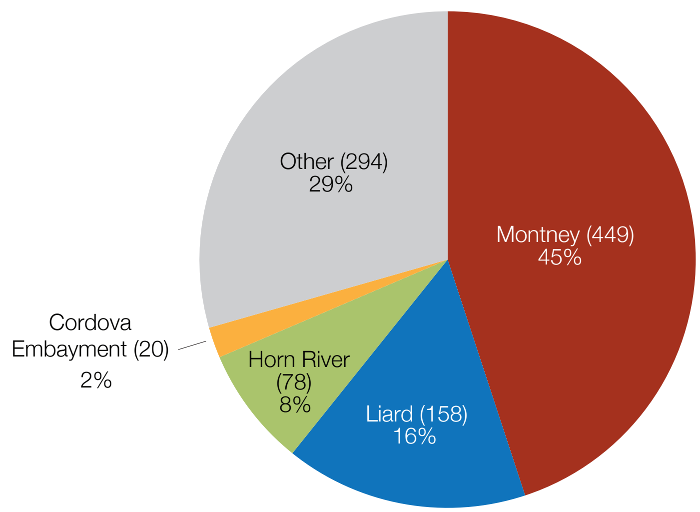
TRIANGULATION TOOL #1: WHAT IS FNFN'S GAS PRODUCTION AS A PROPORTION OF CURRENT WCSB TOTALS? If the proportion of WCSB gas produced in FNFN territory were to remain unchanged over the next 25 years, and all WCSB regions were to contribute equally to the LNG supply chain, FNFN territory could be expected to supply only two to three per cent of the total volume of gas required by the B.C. LNG export sector. This assumption is very conservative and likely unrealistic. It assumes that all WCSB plays continue to maintain their current relative level of investment, maturity, size and ownership structures. In the case of FNFN territory, the plays are very large and very immature (only at the beginning of their productive lives), and tenure is tied to a variety of players who are in or have indicated an intent to get into vertical integration in the LNG sector. In addition, virtually all industry estimates indicate FNFN gas plays are likely to grow in importance in relation to B.C. and WCSB gas production over the next two decades. As a result, overreliance on this triangulation method is likely to significantly underestimate future production activity in FNFN territory.

TRIANGULATION TOOL #2: WHAT IS FNFN'S PROPORTION OF WCSB GAS RESOURCES? Actual supply to future LNG facilities will arguably be based more on the size of the remaining resource in the ground rather than current production levels. Evidence from a variety of sources indicates that FNFN shale gas basins are extremely large and attractive versus traditional conventional gas plays. Given currently available information about WCSB gas resources, The author's estimate is that the three FNFN shale basins account for 256 Tcf out of a WCSB total of 999 Tcf of recoverable gas, or 25.5 per cent (Figure 4). However, the study also adopted a low range estimate of recoverable gas in line with low estimates from a variety of sources, at 110 Tcf for the three basins, or 13 per cent of recoverable gas in the WCSB.

The key take away points are that future extraction from FNFN's territory is likely to increase relative to WCSB totals and there is ample supply in FNFN territory shale basins to fuel even high LNG-induced extraction scenarios.

TRIANGULATION TOOL #3: WHAT DO INDUSTRY ANALYSTS ESTIMATE FOR FUTURE LNG PRODUCTION FROM THE HORN RIVER BASIN? Recent estimates are for exponential future growth in gas production in FNFN territory. Most have focused on the Horn River Basin, and include estimates from the National Energy Board (NEB 2011), Nova Gas Transmission Ltd. (2011), Wood Mackenzie (2011), Canadian Association of Petroleum Producers (2012, 2010) and BC Hydro (2013). In general, these published estimates suggest gas production growth from the Horn River Basin in the range of six to 10-fold over the next decade to 25 years, and potentially

Figure 4: Marketable gas potential in WCSB (Tcf)



as much as a twenty-fold increase. These estimates suggest that, if the proportion of LNG-induced gas extraction occurs in parallel with available public estimates of future WCSB gas production proportions sourced from FNFN territory, between 19 and 30 per cent would come from FNFN territory.

TRIANGULATION TOOL #4: HOW COMPETITIVE ARE FNFN'S NATURAL GAS BASINS VS. OTHER WCSB BASINS? This study looked at information about the comparative advantages of different WCSB basins, which may impact the proportion of LNG that would come from FNFN territory. The results of this analysis are summarized in Table 2 on page 12. Arrows pointing up indicate an area of strength for that basin, equals sign indicates neither an advantage nor a disadvantage, and a downward pointing arrow indicates a disadvantage versus the other basins.

If basin-by-basin competitiveness were the primary factor, there would be a reduction in the expected proportion of LNG sourced from FNFN territory due to prioritization of Montney deposits (the "Montney Advantage"). Primary factors influencing the "Montney Advantage" over FNFN territory gas basins include:

a) The approximately 10 to 12 per cent higher "shrinkage" rate for FNFN gas versus Montney and other WCSB gas sources;[8] and

b) The approximately 15 per cent price premium estimated for break-even costs for LNG facilities using FNFN gas resources identified by Macquarie Research (2012).

In the absence of quantitative data, these comparative advantages and disadvantages were integrated qualitatively into estimates of natural gas production from FNFN basins.

8 "Shrinkage" refers to the amount of material removed from the ground that is lost in subsequent processing from raw to sales gas. This can include water, CO_2, and other "impurities," FNFN gas' high CO_2 content is the primary factor increasing its shrinkage rate beyond that from other WCSB formations (B.C. Hydro 2013).

Table 2: Subjective analysis of comparative advantages and disadvantages of WCSB basins[a]					
	Montney	Horn River	Liard	Cordova	Duvernay
EUR/well	=	↑	↑	=	Unknown
Cost per unit of production	↑	↓	Unknown	Unknown	Unknown
Distance to market	↑ or =	=	=	=	=
Presence of Natural Gas Liquids (NGLs)	↑	↓	↓	↓	↑
Total recoverable resource (Section 6.3)	↑	↑	↑	↓	Unknown
Current production and infrastructure capacity	↑	=	↓	↓	↓
Availability of labour	= or ↑	= or ↓	↓	↓	=
CO_2 and other impurities — "shrinkage" level of raw gas	↑	↓	↓	↓	Unknown
Level of vertical integration into LNG sector (Section 6.6)	↑	↑	↑	↑ or =	↑

Note: [a] Note that the criteria are not weighted in this table, meaning no criterion is automatically deemed to be more important to business decisions than any other.

TRIANGULATION TOOL #5: LNG PLANS OF GAS COMPANIES WITH TENURE IN FNFN TERRITORY. The implications for FNFN territory of vertical integration (LNG proponents with gas tenure ties to FNFN territory) depend entirely upon which LNG projects actually proceed. Given the preference in the LNG sector for vertical integration to minimize risk by having control over upstream gas supplies, this variable may prove to be the most important for actual development of FNFN basins versus other gas plays.

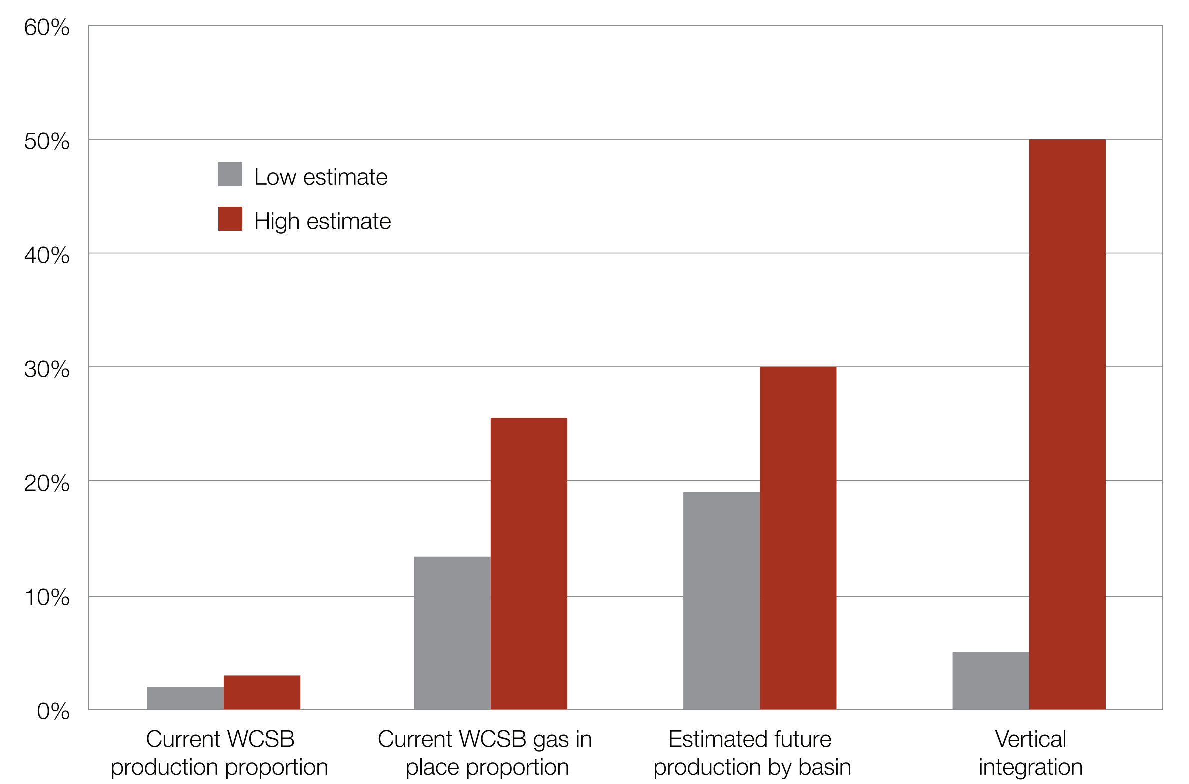
Some proposed LNG facilities have strong links to FNFN territory (e.g. Kitimat LNG, LNG Canada)[9], while others have little or no links to FNFN shale basins (e.g., Pacific Northwest LNG).There is inadequate information to suggest which LNG projects are most likely to proceed and in what order. Therefore, this study has adopted a wide range of possible probabilities. If there is minimal vertical integration into FNFN territory of LNG projects that proceed, the amount of LNG-induced demand attributable to FNFN territory may be very low (e.g. +/- five per cent). If, however, the LNG projects have high FNFN territorial holdings, there is reason to expect some projects will source 50 to 100 percent of their gas from their own holdings in FNFN territory (e.g. Apache/Chevron and Nexen/INPEX/JGC). With it impossible to conclude with confidence which of the currently proposed LNG projects will proceed, this report has adopted a 5 to 50 per cent range of supply from FNFN territory to reflect this uncertainty.

9 The full Phase 1 report shows companies with LNG interests and tenure in FNFN territory.

BASED ON ALL THESE SOURCES, WHAT IS THE RANGE OF POTENTIAL PROPORTIONS OF TOTAL LNG-INDUCED GAS EXTRACTION LIKELY TO COME FROM FNFN TERRITORY? Figure 5 identifies four sets of low and high proportional ranges of FNFN-based supply to B.C. LNG export facilities. The proportions range from two per cent (low estimates of current FNFN territory proportion of WCSB gas production) to 50 per cent (if LNG projects with strong upstream tenure connections to FNFN territory are the primary LNG export projects that proceed).

Not characterized in the table, but a critical fifth consideration in developing realistic scenarios, were FNFN basins' competitive advantages and disadvantages versus other WCSB gas plays. Given all of the factors considered in this analysis, this study concludes that the most realistic range of natural gas to be supplied from FNFN territory as a proportion of total WCSB supply to B.C. LNG exports over the initial 20 year production timeline of 2018 to 2038 is between 10 and 25 per cent.

Figure 5: Range of estimates of proportion of B.C. LNG exports from FNFN territory, by variable



STEP 3: RANGE OF LNG-INDUCED GAS EXTRACTION SCENARIOS FROM FNFN TERRITORY

Table 3 brings together the two main findings of this report to provide a series of potential LNG-induced extraction scenarios for FNFN territory.

Table 3: FNFN LNG-induced gas extraction matrix

LNG demand (2018–2038 average)/ FNFN production proportion	10% FNFN gas	25% FNFN gas
Low scenario: 4.9 Bcf/day	0.49 Bcf/day	1.23 Bcf/day
High scenario: 10.7 Bcf/day	1.07 Bcf/day	2.68 Bcf/day

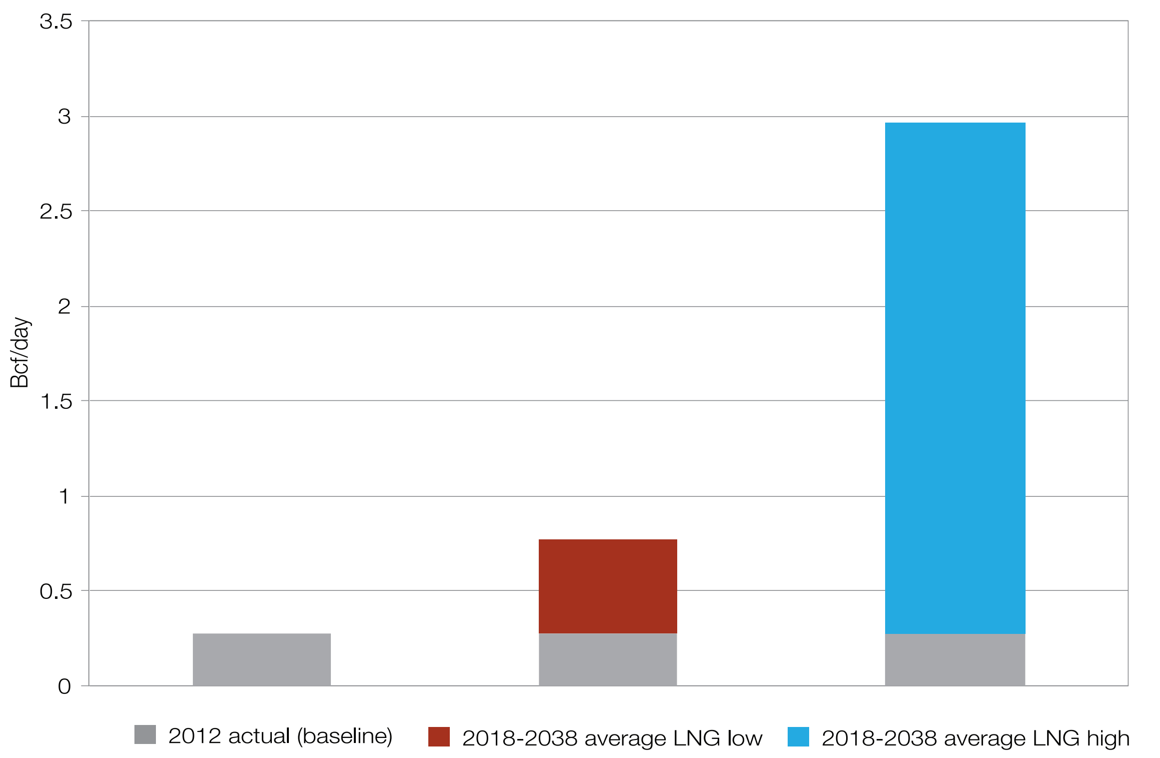
Note: This table includes only new gas production required to support the LNG export sector. In contrast, Figure 6 adds LNG demand on top of current FNFN gas production rates. Note that Figure 6 assumes for the sake of simplicity that there will be no growth in these production rates for the domestic and North American markets from current rates.

These numbers equate to between 178 and 978 Bcf/year of natural gas extracted from FNFN territory as a result of the B.C. LNG export sector. When converted to LNG production, the amount equates to between 3.75 and 20.5 million tonnes per annum. This volume ranges from an amount sufficient to support a small portion of a single medium-sized LNG facility to enough gas to support a large LNG facility or two medium-sized LNG facilities.

A large difference exists between the highest predicted FNFN gas production scenario and the lowest (2.68 Bcf/day vs. 0.49 Bcf/day). This six-fold difference provides a sufficiently broad view of potential natural gas development scenarios to capture the majority of potential effects on FNFN territory from the fledgling B.C. LNG sector.

The key finding from this analysis is confirmation that significant increases in the amount of gas produced from FNFN territory are coming. As illustrated in Figure 6, even the lowest LNG demand scenario in FNFN territory would see a more than 160 per cent increase over 2012 gas production levels from shale basins in FNFN territory of 281 Mmcf/day. At the high end of the realistic scenario scale, that number jumps to an almost 10-fold increase.

Figure 6: Increase in total production from shale basins in FNFN territory under low and high LNG-induced-gas extraction scenarios



SUMMARIZING LNG-INDUCED NATURAL GAS EXTRACTION SCENARIOS FROM FNFN TERRITORY

Based on triangulation of the secondary data available, the Phase 1 study concluded:

1. B.C. LNG exports will be between 37.5 and 82 mtpa, starting about 2018, and lasting over an initial 20 year period (this study did not estimate the lifetime of the B.C. LNG sector; however it will likely be 50 years or longer);
2. 10 to 25 per cent of the gas for B.C. export facilities will come from FNFN territory; and
3. As a result of #1 and #2, development of a B.C. LNG export sector will induce between 490 million and 2.68 billion cubic feet per day in additional gas extraction from shale gas basins in FNFN territory.

As a result of LNG export sector requirements, gas extraction will increase by somewhere between 1.6 times and almost 10-fold over 2012 levels. The B.C. LNG export sector will induce significant additional development in FNFN territory. Indeed the reality of this is already apparent, with the attractiveness of the LNG export sector being a major driver identified by industry, government and industry analysts for continuation or resumption of activities within FNFN territory during a North American natural gas supply glut.[10]

The Phase 1 study intentionally erred on the side of conservative estimates where possible in this scenario development exercise. Thus, the likely 10 per cent additional required gas for power generation and transportation in the LNG export production system (U.S. EIA 2012) is not included in the calculations. Nor is the additional 10 to 19 per cent of "shrinkage" (product losses in processing) between raw and sales gas (Walden and Walden 2012). In addition, potential "induced exploration effects," wherein new demand for LNG may see expansion of supply by an amount greater than the LNG requirement, are not included in the calculations.[11]

Taken together, the conservative assumptions underlying the analysis likely reduce the calculated demand on FNFN territory, as compared to the actual demand. Given this built-in conservatism, it is possible that the actual outcomes in terms of LNG-induced gas extraction from FNFN territory may exceed the high end estimated within this study. In contrast, for the same reasons it is extremely unlikely that the low end estimate herein will exceed the actual outcome.

10 Greg Colman, energy analyst for the National Bank, suggests that drilling activity will need to begin long before LNG export facilities are commissioned, and that *some 200 per cent of export capacity has to be available at the time exports commence* (Schaefer 2013); emphasis added). As a result, even before LNG final investment decisions are made, large amounts of exploration and well completion is expected.

11 Priddle (2013a), following work completed by Ziff Energy Group for WCC Ltd.'s NEB export licence application, identifies a potential replacement ratio approaching 1.4 times the required gas feedstock for an LNG facility, meaning that the induced demand from LNG is likely to cause increased gas development and extraction over and above that required to feed the LNG facilities.

PHASE 2

Effects of LNG-induced Gas Extraction on FNFN Territory

OVERVIEW OF PHASE 2

With realistic scenarios of how much additional gas will be extracted from FNFN territory to fuel the B.C. LNG sector in hand, the Phase 2 study focused on estimating how this new demand will change FNFN territory — and what impacts these changes will have on the environment.

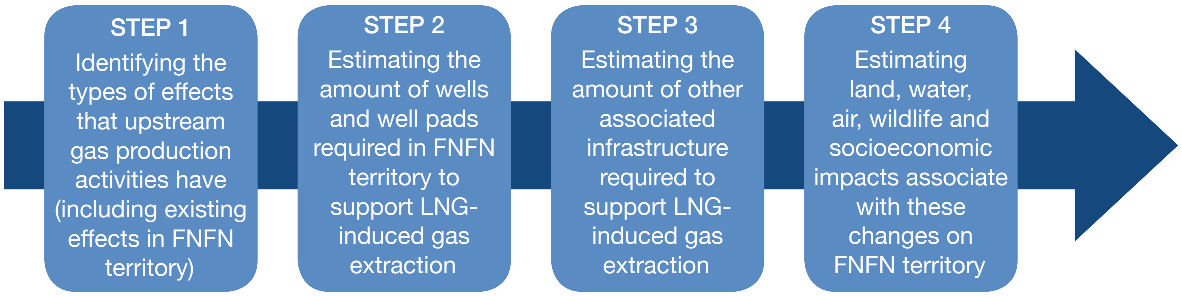
The Phase 2 study focused on estimating how this new demand will change FNFN territory — and what impacts these changes will have on the environment.

WHAT KINDS OF QUESTIONS ARE EXPLORED IN THE PHASE 2 STUDY? Using some basic assumptions about gas wells and associated infrastructure development, and the estimates made in Phase 1 of the study as a basis, Phase 2 looks at:

- What types of infrastructure are required, and types of effects are caused, by upstream gas sector activities?
- What effects have already been caused by the upstream gas sector in FNFN territory?
- In light of the Phase 1 LNG-induced demand scenario findings, what range of additional physical works and activity can be expected in FNFN territory in support of the B.C. LNG export sector over the first 20 years?
- What are some of the likely environmental and socio-economic effects of this additional gas sector activity in FNFN territory?

HOW WERE THE PHYSICAL IMPACTS OF THE GAS PRODUCTION FORECASTS FROM PHASE 1 ESTIMATED? The approach used in Phase 2 of this study involved four steps, shown in Figure 7 on the following page.

Figure 7: Steps for estimating the physical impacts of the gas production forecasts from Phase 1



What are the limitations and assumptions of the Phase 2 study?

Limitations include:

1. Unless otherwise noted, effects are considered only within the three shale gas basins in FNFN territory. Effects of gas activity within FNFN's core territory outside these three basins are not considered.

2. Only future gas sector effects are predicted. This is not a cumulative effects assessment.

3. Effects are limited to the first 20 years of the fledgling B.C. LNG export sector (2018-2038).

Phase 2 assumptions include:[12]

1. All new gas sector growth in FNFN territory will be from LNG (a conservative assumption[13]).

2. 12 wells per well pad will be the norm over the study period (currently, this is a conservative assumption).

3. LNG will require all new wells on top of existing wells in FNFN territory (a liberal assumption).

4. Shrinkage and other gas losses are not included in the calculations (a conservative assumption).

Even with the limitations and assumptions, the author suggests that, by erring primarily on the side of making conservative estimates of future change, this study provides a realistic set of scenarios of future change on FNFN territory.

12 All assumptions are detailed in Section 2.2 of the Phase 2 document.

13 In this study, the term "conservative" is used whenever an assumption is made that likely means that estimates made as a result of the study are likely to be lower (e.g., in term of the number of wells required in FNFN territory) than actual results. The term "liberal" applies to situations where an assumption may lead to estimates higher than actual results.

STEP 1: ACTIVITIES AND EFFECTS OF THE UPSTREAM GAS SECTOR

What are the key physical works and activities involved in the upstream gas sector?

In the exploration phase, seismic lines (linear clearings) are cut through the forest to explore the potential of the area. Lines can be anywhere from 1.5 to 5 m in width.

Once a prospective area has been identified, roads are built to allow access for equipment and workers. Gas industry roads are typically 10 to 30 m wide.[14]

Well pad complexes are built by clearing the forest and leveling the ground. Conventional well pads were about 1 hectare (ha), while recent well pads with multiple wells can be up to 16 ha in size (up to 400 x 400 metres — see Figure 8 below). Wells are drilled — for gas, water inputs, and in some cases deep disposal wells for produced water. Hydraulic fracturing of the wells occurs, a process that includes a large amount of vehicle movement, water withdrawals, and inputs into the well — such as frac sands and other additives.

Pipelines send the gas to a processing facility where impurities such as water, hydrogen sulfide and carbon dioxide (CO_2)[15] are removed. From here, the processed or "sales" gas goes to market, also via pipeline. Pipelines are developed either along existing right of ways or sometimes through new linear clearings. Water crossings are required where the pipeline encounters a watercourse, which may require horizontal directional drilling under the streambed or short-term diversion of the stream using "open cut" construction techniques. Right of

Figure 8: Example Multi-Well Pad Complex in Northeastern B.C. (B.C. OGC 2013b)

14 Depending on whether they are spur roads or arterial roads connecting to main transportation corridors. For example, the Forest Practices Board (2011) used an estimate of 25 metres ROW for an average two-lane gravel road in a cumulative effects modeling exercise for the northeastern B.C. gas sector.

15 One of the major "impurities" removed at FNFN territory gas plants is CO_2, which is in much higher amounts in raw gas than in other B.C. unconventional gas sources (e.g., Horn River CO_2 averages 12 per cent of raw gas). Currently, this CO_2 is vented directly to the atmosphere.

ways for larger pipelines can be 30 metres in width or more and are actively managed to prevent trees from re-growing in the right of way.

Large pipelines require other facilities, including compressor stations, which generate power to increase the pressure of the gas in the pipe and maintain flow. Compressor stations may require additional land clearing. Other supporting facilities can include batteries for storage of liquids, dehydrators, flare sites and metering sites.

In northeastern B.C., over 75% of boreal caribou range is already tenured and being developed for petroleum and natural gas. This level of activity is reported to exceed a disturbance threshold in 12 of 15 Core Habitat areas, a point at which "caribou populations achieve negative population growth." (Environmental Law Centre 2013)

Water gathering, storage, management and treatment facilities are also needed, and can be substantial in number and size. These include ground water wells, water storage pits (dugouts) and deep well disposal sites.[16] Other sites include borrow sites for granular materials needed for road building, site stabilization and "frac sands" — a key ingredient used in fracking. Work camps are needed to house what is often a primarily out-of-region workforce.

What are the environmental impacts of gas sector activities?

The activities described above bring with them a series of environmental impacts. For example, trees need to be removed for seismic lines, pipeline right-of-ways and drill pad locations, new access roads, and a variety of other facilities, and many of these areas are not reclaimed until after the operations are shutdown. These linear and areal disturbances increase habitat fragmentation, which has been shown to adversely impact woodland caribou populations and other wildlife species. New roads means better access for people, and greater access means increased hunting pressures and potential for higher wildlife mortality from vehicle collisions.

During the operations phase, environmental impacts include contamination of soil and water (ground and surface), and in the case of fracking, diversion of large amounts of surface water. Gas operations can also cause local air quality problems from gaseous and particulate emissions. They also contribute heavily to B.C.'s greenhouse gas (GHG) emissions footprint, which is linked to climate change.

Key Environmental Impacts: an overview

- **IMPACTS ON WILDLIFE,** both through direct habitat removal and mortality from roads, and through indirect impacts on air and water quality, which can increase the incidence of disease in some wildlife species. Moose are impacted primarily through loss of wetland habitat and the potential for contamination through exposure to polluted hydrocarbons. Woodland caribou, a SARA-listed species[17] — are highly vulnerable to habitat fragmentation, and

16 For example, Campbell and Horne (2011) report that the B.C. OGC approved a Nexen plan to dig a pit measuring 560 metres by 200 metres, and 13 metres deep, near the Horn River Basin, to be used as a water reservoir that would hold up to 1.5 billion litres of water.

17 In the federal Species at Risk Act, woodland caribou (boreal population) are listed as threatened (www.sararegistry.gc.ca/default_e.cfm).

require large amounts of undisturbed habitat to evade predators. Furbearers, including lynx, marten, and fisher, have been shown to decline in regions subjected to industrial development.[18] Birds in boreal forests are sensitive to industrial disturbance — many forest bird species avoid using habitat within 100 metres of roads, pipelines, well pads and other industrial facilities.[19]

- **IMPACTS ON HABITAT AND VEGETATION,** through directly removing forests and other vegetation, and indirectly by increasing the amount of light into the surrounding forest. Johnson et al. (2010) suggest that for every acre of forest cover cleared by gas development, an additional 2.41 acres of edge effects could be felt in adjacent forest areas. The land clearing required for shale gas infrastructure, including roads, seismic lines well pads, and pipeline networks, contributes heavily to habitat fragmentation, and is perhaps the most significant contributor to cumulative effects on the biophysical environment in northeastern B.C.

- **IMPACTS ON SOIL:** Disturbances associated with shale gas development, including increased erosion and changed sedimentation patterns, can have a noticeable impact on soil productivity. Right of way clearing and roads are the big culprits, as soil compaction impedes vegetation regrowth in these areas.

- **AIR QUALITY AND CLIMATE EFFECTS:** The effects of shale gas production on GHGs — gases that are known contributors to climate change — may be higher than originally thought (Howarth et al. 2011; Pembina Institute 2013; FNFN 2013; Campbell and Horne 2011). This is partially due to fugitive methane emissions, which can leak from the wellbore into groundwater or other areas near or at the surface, and partly due to high CO_2 amounts in some deposits, a particularly concern with the Horn River Basin. As one study put it, "the cleanest-burning fossil fuel might not be much better than coal when it comes to climate change" (Tollefson 2012). Apart from greenhouse gases, upstream gas activities may also increase adverse air quality through a variety of contaminants emissions.

- **IMPACTS ON WATER AND AQUATICS:** Hydraulic fracturing requires massive amounts of water — much more than conventional gas — especially in shale basins like those in FNFN's territory. Much of it comes from surface waters. Fracking is also associated with a risk of water contamination, as it introduces large amounts of chemicals into the subsurface. One study estimated that fracking chemicals represent 1/200th of the total liquid inputs in a fracturing job (Linley 2011). Studies have shown that wastewater and flowback from hydraulic fracturing may be highly saline and must be re-injected into deep well aquifers or it will kill vegetation and degrade soil quality on land (Campbell and Horne 2011). The future effects of wastewater injected deep underground remain largely unknown. Gas wells close to surface waters may impact water quality in those areas, and studies have documented concerns about groundwater contamination through casing failures and improper frack water disposal.

- **IMPACTS ON FISH AND FISH HABITAT:** Fish are impacted directly through loss of habitat at pipeline and road crossings, changes in water temperature due to a loss of riparian vegetation, and increased fishing pressure. Construction can release soil into streams, negatively affecting fish survival. Lower water levels can impact habitat for some fish. Water contamination can impact riparian zones, and spills have the potential to directly kill fish or contaminate them.

18 Schneider and Dyer 2006; Nielsen et al. 2007.
19 Cumming and Schmiegelow 2004.

- **IMPACTS ON HUMAN HEALTH AND WELL-BEING:** Accidents and malfunctions can impact drinking water supplies. Cancer-causing chemicals in flowbacks may constitute human health hazards. Gas sector activity may also bring social impacts to area residents, including an increase in access to alcohol and drugs, social dysfunction, and increased outsiders in the community. Aboriginal people are often among those most at risk to suffer adverse effects as a result of this particular kind of social and economic change.
- **IMPACTS ON ABORIGINAL CULTURAL PRACTICES:** Gas development may also have widespread impacts on aboriginal land use and harvesting. These impacts may include alienation from the land and water, concerns about travel and harvesting country food, less time spent on the land and associated reduction in knowledge transmission, and an inability or unwillingness to drink water from the land. The increase in non-aboriginal hunting pressure makes it harder for aboriginal hunters and fishers to harvest country food.

Changes in the community and on the land contribute to psycho-social impacts that include concerns about resources becoming contaminated, conflicted feelings about making money by being involved in “destructive” industries, and — above all — a loss of connection to the land. Gas development has also been described as violating “the spirit of the land” and communal stewardship values central to First Nations’ connection with their traditional territory (National Research Council 2003).

Are there other concerns related to hydraulic fracturing?

The B.C. OGC (2012) found that fracking caused increased seismic activity in northeastern B.C. from 2009 — 2011, and recommended further monitoring. Long-term legacy issues are a concern: according to the Environmental Law Centre (2013), B.C. taxpayers are already covering approximately $650 million in liabilities for abandoned resource sector projects, “including many oil and gas sites.” Potential for accidents and malfunctions also grow as more facilities and pipelines are built.

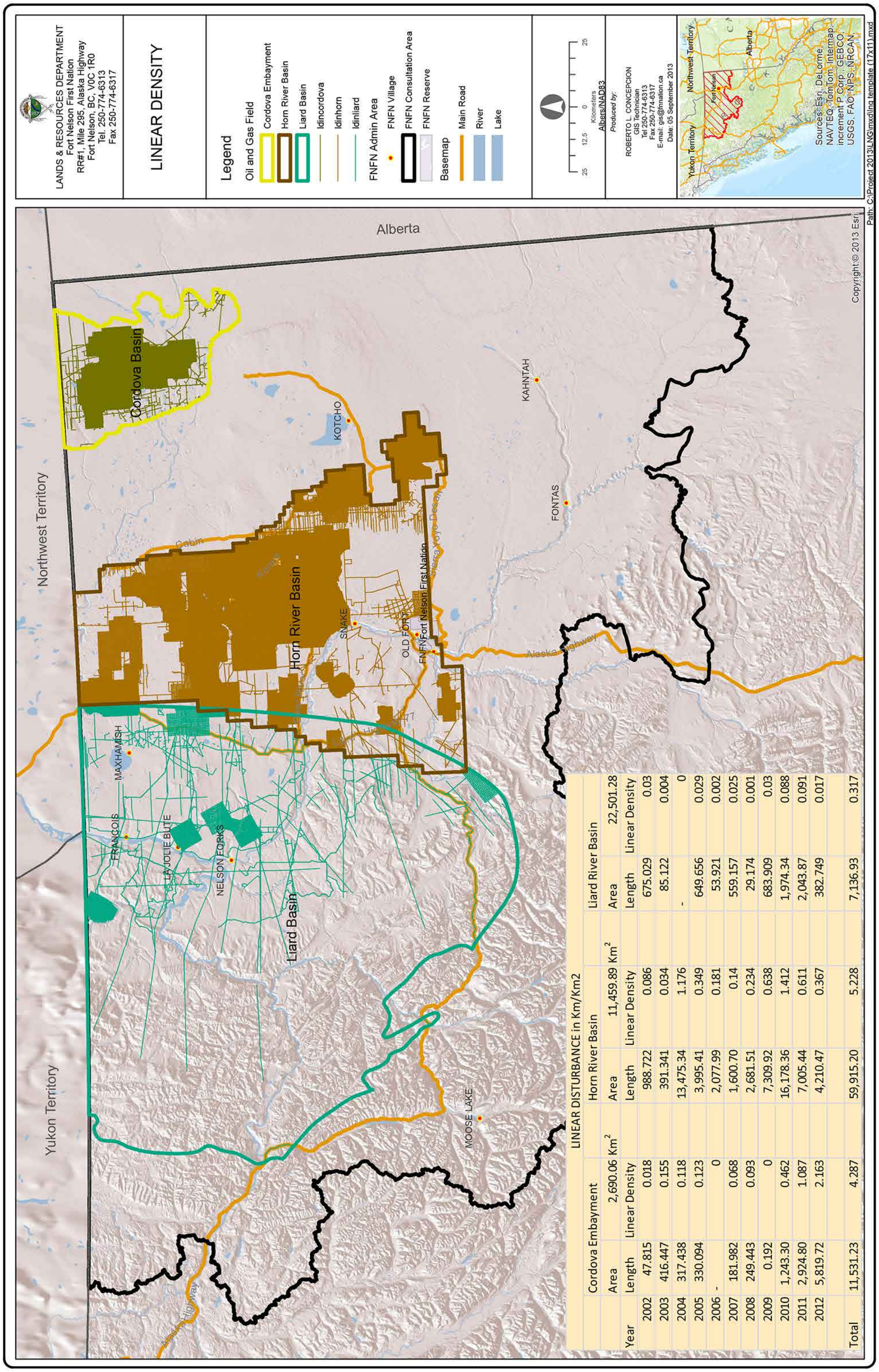
What has happened on FNFN territory to date?[20]

Between 2002 and 2012, 12,600 km^2 of land was tenured to gas companies, the majority from 2008 onwards and most of it in the Horn River Basin. Between 2006 and 2013, approximately 299 well pads were developed and 892 wells drilled in the three shale gas basins within FNFN territory. More and more of them over time have been large multi-well pads using hydraulic fracturing, which requires extremely large water, chemical, and “proppant” — sands — inputs. As a result, total water withdrawals in FNFN have grown exponentially over the past decade.

Impacts such as linear disturbances (roads, seismic lines and right-of-way buffers) and large areal disturbances (facilities, gas plants, and well pad clearings) have increased dramatically over the last decade. B.C. OGC data was used to calculate that the total amount of linear disturbance added to the three shale gas basins in FNFN territory as a direct result of gas sector activities between 2002 and 2012 was 78,583 km, or over 2.1 km/km^2 (see Figure 9 on page 23). This led in turn to increased habitat fragmentation, including extremely high linear

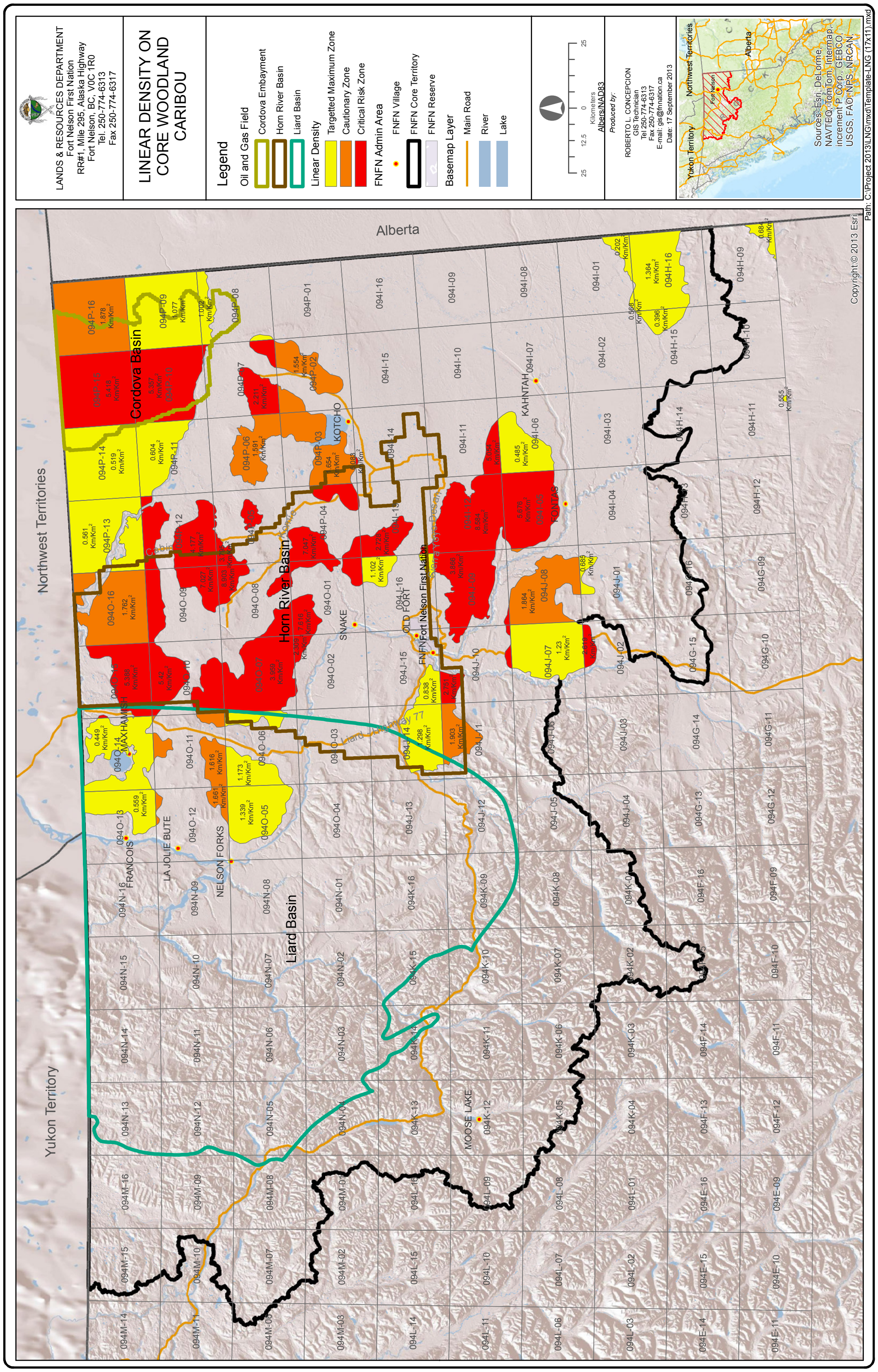
20 Data on linear and areal disturbance were developed in concert with FNFN Lands Department’s GIS team, which has access to B.C. OGC and other GIS map data to make these calculations.

Figure 9: Linear disturbance in FNFN territory as of 2012



LINEAR DISTURBANCE in Km/Km2						
	Cordova Embayment		Horn River Basin		Liard River Basin	
	Area	2,690.06 Km^2	Area	11,459.89 Km^2	Area	22,501.28
Year	Length	Linear Density	Length	Linear Density	Length	Linear Density
2002	47.815	0.018	988.722	0.086	675.029	0.03
2003	416.447	0.155	391.341	0.034	85.122	0.004
2004	317.438	0.118	13,475.34	1.176	-	0
2005	330.094	0.123	3,995.41	0.349	649.656	0.029
2006	-	0	2,077.99	0.181	53.921	0.002
2007	181.982	0.068	1,600.70	0.14	559.157	0.025
2008	249.443	0.093	2,681.51	0.234	29.174	0.001
2009	0.192	0	7,309.92	0.638	683.909	0.03
2010	1,243.30	0.462	16,178.36	1.412	1,974.34	0.088
2011	2,924.80	1.087	7,005.44	0.611	2,043.87	0.091
2012	5,819.72	2.163	4,210.47	0.367	382.749	0.017
Total	11,531.23	4.287	59,915.20	5.228	7,136.93	0.317

Figure 10: Linear disturbance density on core woodland caribou habitat in FNFN core territory and shale basins



disturbance in core woodland caribou (a species at risk) habitat and indeed throughout the Horn River Basin and Cordova Embayment (see Figure 10 on page 24). Many areas in these shale gas basins have seen linear disturbance well above that which causes high potential for extirpation of woodland caribou from their core ranges.

Overall, areal disturbance of over 8,500 km^2, when buffered by 250 metres, has occurred within the over 14,000 km^2 of FNFN territory that is subject to tenure in the three basins. 59 per cent of the Horn River Basin and 54 per cent of the Cordova Embayment is rated as already disturbed using this metric.

B.C. OGC (2013b) suggests that as of 2012, 148,728 hectares of the portion of the Fort Nelson Land and Resource Management Plan area covered by the shale basins, or 2.36 per cent, has been "used" for oil and gas activities. The amounts per basin are 1.28 per cent for Liard, 3.08 per cent for Cordova, and 3.18 per cent for Horn River. However, the B.C. OGC's data refers to surface footprint only and may well not reflect the "impact footprint" or "zone of influence" (ZOI) of these activities on FNFN land and waters. Impacts are felt well beyond the physical limitation of the immediate change in a ZOI. For example, Johnson et al. (2010), in discussion of the effects of shale gas development in the U.S. Northeast, predicted that for every acre of direct disturbance, there are 2.41 more acres subject to "edge effects." If this is the case in FNFN territory, the amount of areas used in the shale gas basins in FNFN territory impacted from oil and gas activities grows from 148,729 hectares to over 500,000 hectares. By this measure, some 8 per cent of the FNLRMP and over 10 per cent of each of the Horn River Basin and Cordova Embayment had likely been impacted by gas sector activity by the end of 2012.

STEP 2: ESTIMATING REQUIRED GAS WELLS AND PADS FOR LNG-INDUCED EXTRACTION

Step 1 established that existing natural gas extraction industry on FNFN territory has already had important impacts on the environment and on FNFN members' way of life. Step 2 turned to estimating the number of additional gas wells — on top of what already exists — that will be needed to meet the expected increase in natural gas demand as the LNG export industry grows.

HOW MANY WELLS WILL BE ON EACH WELL PAD IN THE FUTURE? Using information from industry[21] and the B.C. OGC, it was estimated that 12 wells per pad will be the average during the first 20 years of LNG-induced demand from FNFN shales. This is much higher than historic numbers.

WHAT WILL THE AVERAGE WELL PRODUCTION FROM FNFN GAS EXTRACTION BE IN THE FUTURE? Using a variety of sources, the study calculated an expected average of 10 Bcf/well as the estimated ultimate recovery (EUR)[22] from wells in the three FNFN basins of interest. Basin "decline rate" was also a consideration when assessing the relevance of proxy studies for estimating FNFN well requirements. A high decline rate such as that found in the Horn River Basin (Hughes 2014) means that the well replacement process needs to be accelerated, with additional wells continuously drilled to keep production rates at the same level.

21 For example, Groat and Grimshaw (2012) estimate wells per pad at between 10 and 16 for shale gas development, while B.C. OGC (2013a) suggests that up to 16 wells per pad have been drilled in the Horn River Basin. In addition, Apache Corporation's Liard Basin Development Model uses 12 wells per pad as a modeling assumption.

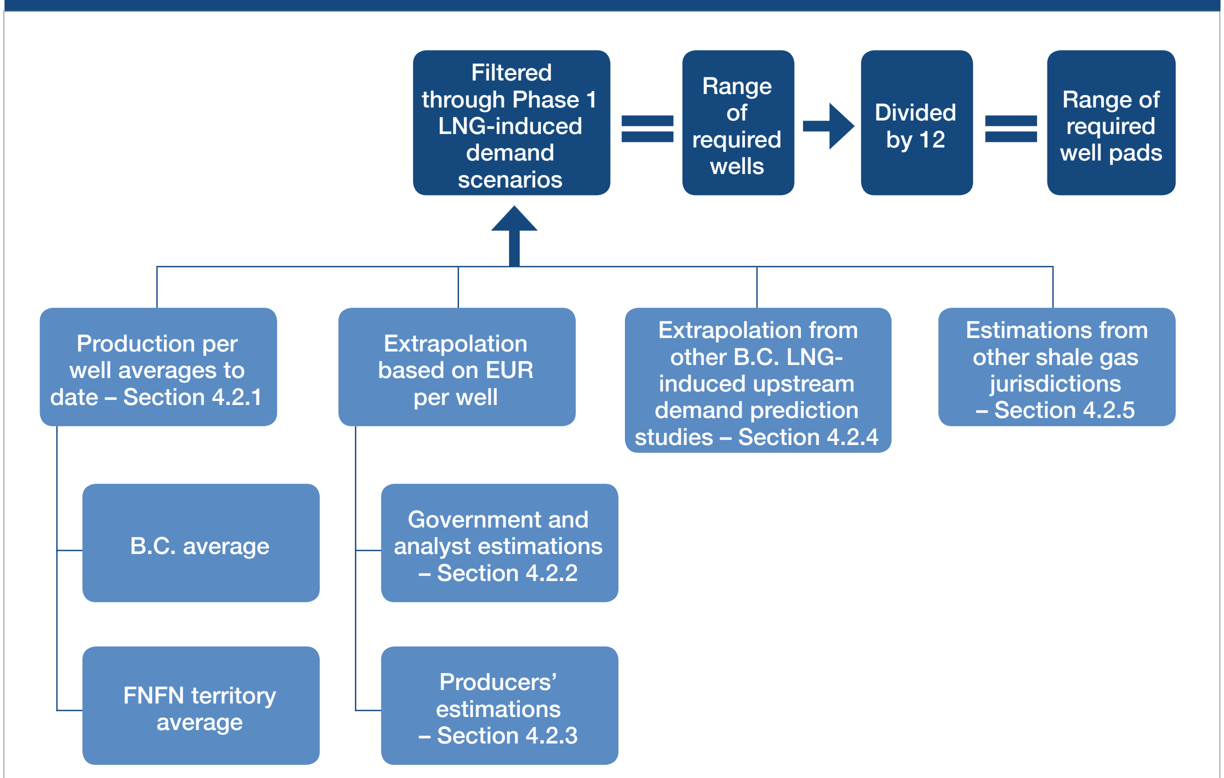
22 Sometimes called "expected ultimate recovery," EUR is the total volume of gas recoverable under current technology and present and anticipated economic conditions, usually estimated by well averages in an accumulation or for the entire accumulation (a play or basin). 10 Bcf/well EUR is much higher than historic levels, reflecting both the conservative approach of this study and increasing well returns in the burgeoning shale gas era.

How many wells and well pads are required?

The study triangulated data from a variety of sources to identify a realistic range of required wells in FNFN territory to fuel LNG sector demand over its first 20 years, as shown in Figure 11 (references in Figure 11 to sections are to sections in the full Phase 2 report):

- **THE CURRENT AMOUNT OF WELLS AND WELL PADS PER UNIT OF PRODUCTION IN B.C. AND FNFN TERRITORY.** It was estimated that the average B.C. well produces 0.44 Mmcf/day. Calculations from current production in the three FNFN shale basins yielded an average rate of between 0.45 and 0.75 Mmcf/day per well. Since this is an underestimate of potential future production, the author concluded that there is little to be gained from extrapolating future well requirements in FNFN territory based on the current average.
- **DIRECT EXTRAPOLATION FROM ESTIMATED FUTURE PRODUCTION RATES PER WELL IN FNFN TERRITORY.** Using a projected Expected Ultimate Recovery (EUR) per well of 10 Bcf for FNFN shale basins, it was calculated that somewhere between 356 and 1,950 new wells would be required to produce the required gas. However, this too is a simplistic metric because replacement wells are not incorporated into the analysis.
- **FUTURE ESTIMATES BY FNFN TERRITORY PRODUCERS.** Based on numbers presented by Apache Corporation in modeling its plans for the Horn River Basin (KM LNG 2010), an estimate was derived that between 731 and 3,995 wells would be required in FNFN territory to meet LNG-induced demand between 2018 and 2038. These numbers are estimated to be the most realistic of any of the proxy studies used.

Figure 11: Inputs used to estimate wells/pads required in FNFN territory



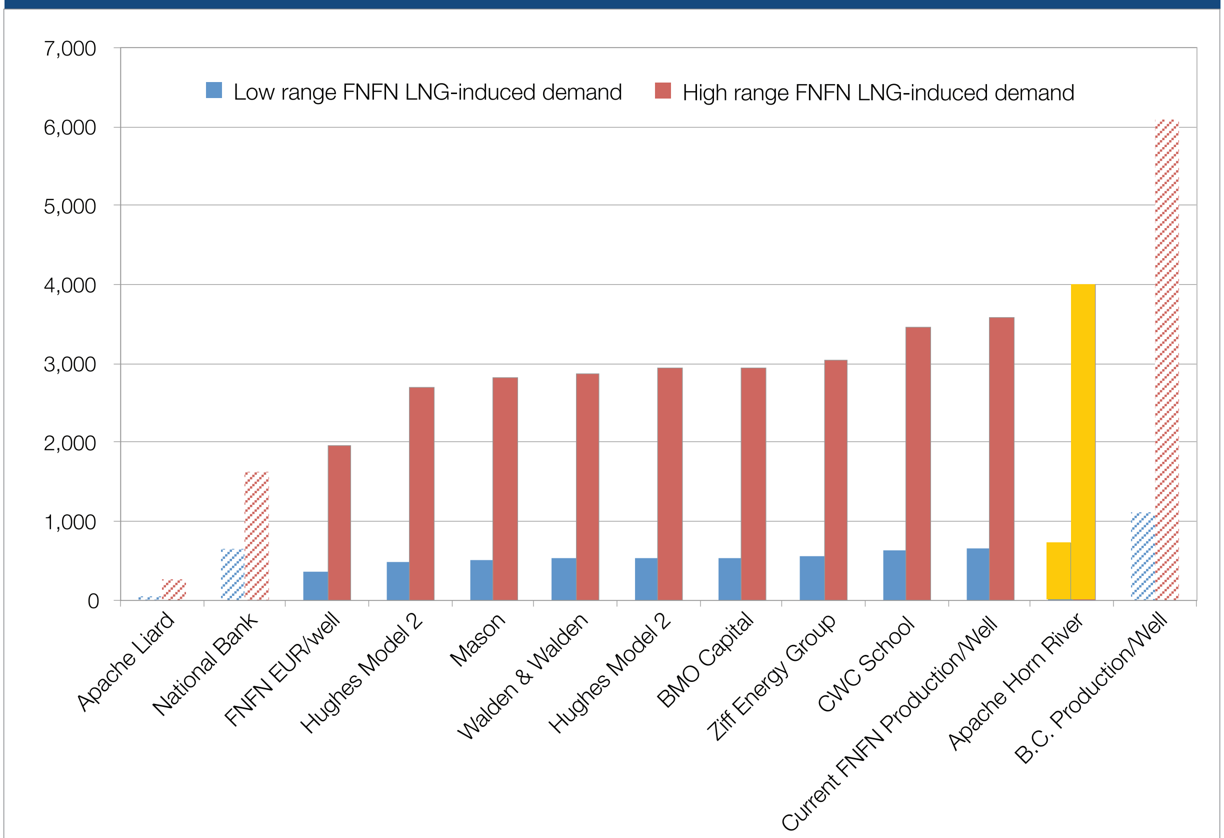
- **SPECIFIC ESTIMATES OF FUTURE WELLS REQUIRED TO FUEL B.C. LNG EXPORT-INDUCED DEMAND.** Using one extrapolation method based on figures from Hughes (2014), it was estimated that over the 20 years examined in this study, between 478 and 2,949 wells would be required in FNFN territory over the first 20 years of LNG-induced demand. Proxy data from Walden and Walden (2012) suggests a similar 527 to 2,881 wells requirement.

- **ESTIMATES FROM OTHER SHALE GAS JURISDICTIONS** (e.g., Ziff Energy Group 2013; Mason 2011) were also utilized, and found requirements for between 517 and 3,052 wells. Results are shown in Figure 12.

Each proxy study had strengths and weaknesses, so every effort was made to use as many as possible to help triangulate a reasonable range. EUR/well adjustments were made where possible to increase to 10 Bcf EUR/well, thus reducing expected well numbers.

In all, 13 different triangulation tools were considered. Estimates where confidence in their applicability was very low were removed from consideration (the striped bars). As Figure 12 shows, 7 of the 13 estimates are tightly grouped between 478 and 632 wells in the low range LNG-induced gas extraction scenario and 2,704 and 3,457 in the high end scenario, a strong indication of the reasonableness of this range of estimates. Despite this, the author's opinion is that a candidate for "most confident" estimate remains Apache's Horn River Basin modeling from which the author estimated between 731 and 3,995 wells required in FNFN territory over the first 20 years of B.C. LNG exports, noted in gold in Figure 12.

Figure 12: Range of Estimates of Number of Wells Required in FNFN Shale Basins to Support LNG-Induced Gas Extraction, 2018 to 2038



Thus, it is estimated that LNG-induced demand will require between 356 and just under 4,000 wells to be drilled in FNFN territory between 2018 and 2038, with the most likely amount being between 731 and 3,995 wells. Using the 12 wells per pad metric, this will require the development of between 30 and 333 large 12-wells per pad complexes in FNFN territory.

STEP 3: ESTIMATING OTHER REQUIRED PHYSICAL WORKS AND INPUTS

HOW WERE ASSOCIATED PHYSICAL INFRASTRUCTURE NEEDED TO SUPPORT THE ESTIMATED NUMBER OF WELLS? Two input types were used to make this estimate:

- A "captured case study" of gas infrastructure growth in recent years in FNFN territory. B.C. OGC data on gas sector activity in FNFN core territory and in the three shale gas basins between 2006 and 2013 was used to estimate the amount of infrastructure required per well or well pad.
- Proxy studies from other shale deposits and conventional gas sectors, tempered by knowledge of changing technology such as greater water requirements and more wells per pad.

To calculate the total other physical works required to support the LNG sector, an estimate of the relationship between wells and other physical works and activities was required. For a hypothetical example:

> **IF** 1,000 wells were needed to support the LNG sector, and there is a typical requirement for 2.5 km of new road per well, **THEN** it can be predicted that a total of 2,500 km of new road will be needed to support LNG-induced gas extraction from FNFN territory.

Findings of per well and per well pad expected physical works and activity requirements from the FNFN territory case study and the proxy studies from other jurisdictions are listed in Table 4 on page 29, along with the selected value taken forward to the effects modeling exercise.

Table 4: Summary of estimates average physical works required per well/pad			
Physical work type	**FNFN case study (2006–2013)**	**Proxy studies**	**Chosen metric for FNFN LNG demand study**
Wells per well pad	2.12 to 2.98	n/a	12 wells per pad
Gas industry roads (km per well)	5.22 to 9.88 km	2.5 to 9 km	5 km per well pad (lower than current rate due to existing infrastructure)
Pipeline	8.64 km per well	3 to 20 km per well; 7,500 km per each new Bcf/day of production	Two metrics: 1) 4.5 km per well pad (reflects discount due to existing infrastructure); 2) 3,750 km per each additional Bcf/day
Seismic (km per well)	64 to 66 km	8 to 17 km	48 km per well pad or 4 km per well" (reflects already completed seismic in many places)
Water withdrawals – locations	1.34 to 1.76 water withdrawal locations per well	n/a	1.76 water withdrawal locations per well (higher number to reflect growing water requirements)
Water withdrawals – extraction	20 to 22 million litres per well	31 to 80 million litres per well	31 to 80 million litres per well (recent wells trending upwards)
Water– disposal locations	19 to 64 wells per disposal locations	n/a	19 wells per disposal location (lower ratio reflects growing water use per well)
Water – storage/dugouts	0.5 to 1.33 wells per water storage location	n/a	2 water storage locations per well pad (note measured by well pad)
Water treatment facilities	One facility per 300 to 400 wells	n/a	One water treatment facility per 350 wells
Work camps	One work camp per 3.5 to 4 wells	n/a	One work camp per 20 wells (reflects existing infrastructure)
Gas plants	One gas plant per 54 to 170 wells	One gas plant per 158 wells	Two metrics: 1) one new gas plant per 150 wells; 2) one new gas plant per each new 600 Mmcf/day
Compressor stations	One compressor per 12 to 36 wells	One compressor every 48 to 112 km of pipeline	One compressor station for each 112 km of new pipeline
Borrow pits	1.84 borrow pits per well	n/a	1.5 borrow pits per well (reflecting existing infrastructure)
Waste disposal sites	One disposal site per 2.4 to 4 wells	n/a	One disposal site per 4 wells
Drill rigs	n/a	8-20 drill rigs per Bcf	14 drill rigs per Bcf (median)

From the chosen proxy number for each category (the last column in Table 4), the study then estimated the total physical works requirements for low and high growth LNG-induced demand scenarios (Table 5 on page 30).

Table 5: Summary of proxy estimates of required wells to support LNG-induced demand in FNFN territory				
Proxy study	Estimate of required FNFN wells		Strengths and limitations of proxy study	Confidence level
	Low estimate	High estimate		
Current B.C. average production rates per well	1,112	6,084	Includes conventional and unconventional wells; no replacement wells; EUR not adjusted	Very low
Current FNFN production rates per well	653 to 1,089 (only the lower number is modeled forward, to be conservative)	3,573 to 5,956 (only the lower number is modeled forward, to be conservative)	From FNFN territory but artificially depressed by low gas prices; no replacement wells; higher number includes shale and conventional wells	Low (for low end of each range) to very low (for high end of each range)
EUR/well estimates (the author adopted 10 Bcf/well EUR)	356	1,950	Reflects estimated average EUR/well in FNFN territory, but this is higher than historic; no replacement wells	Low
Apache's Liard Basin Development Model	50	265	Based on unheard of high EUR of 74 Bcf/well; small sample size; no replacement wells	Very low
Apache's (KM LNG 2010) Horn River Basin Model	*731 (reduced by 19 per cent to reflect "shrinkage" in original model)*	*3,995 (reduced by 19 per cent to reflect "shrinkage" in original model)*	*Horn River Basin data used; realistic 12 Bcf per 15 frac well and an IP of 10.2 MMcf/day; includes replacement wells*	*Moderate to high (highest confidence)*
National Bank (2013)	650	1,625	Not pinned to Phase 1 estimates; uses a simple 10 and 25 per cent calculation; no replacement wells	Very low
Hughes (2014) Model 1 — Average wells per year extrapolation	539	2,949	Specific to northeast B.C. -LNG demand; EUR/well adjusted; includes replacement wells but also includes domestic demand	Moderate to low
Hughes (2014) Model 2 — Visual approximation from tabular information	478	2,704	Specific to northeast B.C. -LNG demand; EUR/well adjusted; includes replacement wells; visual analysis of graphical data	Moderate
BMO Capital Markets (2011)	541	2,956	EUR adjusted; data from northeast B.C; includes replacement wells	Moderate to high
Walden and Walden (2012)	527	2,881	Horn River Basin data used; EUR adjusted	Moderate to high
Ziff Energy Group (2013)	558	3,052	Horn River Basin data used; EUR adjusted	Moderate to high
Mason (2011) Fayetteville well production profiling	517	2,826	EUR adjusted; does not account for higher FNFN decline rates; includes replacement values	Moderate
CWC School of Energy hypothetical shale gas deposit	632	3,457	EUR assumptions rounded up to 10 Bcf/well, but original EUR used is unknown	Low

STEP 4: ESTIMATING EFFECTS OF LNG-INDUCED GAS EXTRACTION ON FNFN TERRITORY

Armed with estimates of total physical works and activities required to support low and high end LNG-induced gas extraction from FNFN territory, the Phase 2 study turned to a final question: What impacts will this have on FNFN territory over the next 20 years?

WHAT INDICATORS WERE USED? To look at the impacts of LNG-induced demand on FNFN territory, this study calculated a number of key indicators: [23]

- Linear disturbance (km of road, pipelines, and seismic lines);
- Areal disturbance (hectares of land physically disturbed by well pads, facilities, and other non-linear disturbances, along with larger indirect Zones of Influence of gas sector activities on the environment);
- Water use (water required in the fracking process only; additional requirements in support of the gas sector are not estimated herein);
- Frac sands (tonnes required);
- Frac additive chemicals (litres required); and
- GHG emissions.

Estimated average sizes (in km or in hectares or km^2) for facilities and infrastructure types were triangulated from various sources, including previous gas sector future scenario modeling exercises and B.C. OGC permit applications, among others.[24]

WHAT ARE THE RESULTS? Table 6 on page 32 provides a summary of the effect that the low and high end natural gas extraction scenarios would have on the various indicators of environmental impacts. All key indicator estimates are limited to the first 20 years of the LNG export sector, from approximately 2018 to 2038.

23 No effort is made in this initial modeling exercise to characterize secondary effects outcomes of these initial impacts on key indicators, such as the effects of linear disturbance on woodland caribou and other wildlife species. Further work will be required to estimate LNG-specific and cumulative effects on wildlife, fish, vegetation and other Valued Components.

24 See Table 10 in the full Phase 2 report for these estimates and their sources.

Table 6: Estimating total LNG-induced effects loads in the three FNFN shale gas basins, by key indicator

Key effects indicator	Low growth — 490 Mmcf/day requires…	High Growth — 2.68 Bcf/day requires…
Total linear disturbance (roads plus 33 per cent of pipelines plus seismic)	1,635 to 3,840 km	9,083 to 20,982 km
Non-seismic linear disturbance (roads plus 33 per cent of pipelines)	195 to 918 km	1,059 to 4,998 km
Total direct areal disturbance[a]	3,053 to 6,813 hectares (30.53 to 68.13 km^2)	16,441 to 37,457 hectares (164.41 to 374.57 km^2)
Total impact footprint (physical footprint plus ZOI 2.41 times larger)	10,411 to 23,234 ha (104.11 to 232.34 km^2)	56,063 to 127,727 ha (560.63 to 1277.27 km^2)
Water usage (wells only)	11 to 58.5 billion litres	60.4 to 320 billion litres
Frac sands required	1.42 to 2.9 million tonnes	7.8 to 16 million tonnes
Frack chemical additives required	55 to 293 million litres	302 million to 1.6 billion litres
GHG emissions (CO^2e – see section 5.1.5)	2.6 million tonnes per year	15.1 million tonnes per year

Note: This table estimates only additional effects associated with LNG-induced demand, not existing effects or effects associated with North American gas supply activities in FNFN territory. In fact, these effects would all relate to one another as combinatory, or cumulative, effects. For example, the 1,635 to 20,982 km range of additional linear disturbance will be added to an existing amount of over 78,000 km of linear disturbance in the three FNFN shale gas basins from 2002 to 2012, and continuing linear disturbance effects ongoing between 2013 and 2017, prior to the start date for this modeling exercise.

[a] This was calculated by adding the total expected areal disturbance in square km to the square km calculated for linear disturbances by type (e.g., 100 km of 20 metre wide roads = 2 km^2 or 200 hectares).

Some of the key results are summarized below:

- **LINEAR DISTURBANCE:** LNG-induced gas extraction will add between 1,635 and 20,982 km of linear disturbance to the three shale gas basins in FNFN territory. This includes 1,440 to 15,984 km of seismic line cutting and 195 to 4,998 km of wider road and pipeline development.

- **AREAL DISTURBANCE:** LNG-induced gas extraction will add 30.5 to 375 km^2 of direct areal disturbance to the three shale gas basins in FNFN territory. This direct physical footprint includes well pad clearing, clearings for other facilities, and linear developments converted to areal disturbance. In addition to this direct physical footprint, the findings identify a total impact footprint (including a disturbance Zone of Influence) of 104 to 1,277 km^2.

- **WATER USAGE:** LNG-induced gas extraction will require the withdrawal and use of 11 to 320 billion litres of water from surface water bodies and ground water sources in the three shale gas basins in FNFN territory.[25] An additional 60 to 666 water storage facilities and a wide variety of other water treatment and disposal sites will also likely be required in support of water management.

- **PROCESS ADDITIVES:** LNG-induced gas extraction will require the use of between 1.4 and 16 million tonnes of frac sands and other proppants in the three shale gas basins in FNFN territory, much of it likely sourced from open pit mines in FNFN territory. In addition, 55 million to 1.6 billion litres of chemical additives would be used in the hydraulic fracturing process.

- **GHG EMISSION EFFECTS:** CO_2 and other GHG emissions have been closely linked to climate change, which may see catastrophic environmental effects at the global and provincial levels. The Pembina Institute (2013) and Clean Energy Canada (2013) both estimate that almost one tonne of CO_2e will be released into the atmosphere for every tonne of LNG exported from B.C.[26] The largest portion would come from emissions from extracting and processing natural gas prior to transportation by pipeline. This study calculates that CO_2e emissions from upstream activity in FNFN territory in support of the B.C. LNG export sector would be in the range of 2.6 and 15.1 million tonnes per year. The high end (15.1 million tonnes per year) would exceed B.C.'s 2009 GHG emissions from the entire natural gas extraction and processing sector.[27] The high end estimate is over 25 per cent of B.C.'s total 2011 GHG emissions, and would represent over a third of the amount of total GHG emissions allowed under B.C.'s legislated 2020 reduction target.

25 This estimate includes the use of water in hydraulic fracturing of wells only. Further research into how much water is being used for other gas sector activities would be an important contribution to cumulative effects assessment in the region.

26 This number only includes sources of emissions from upstream, midstream (pipelines), and LNG facilities themselves. It *does not* include the emissions from the customers in Asia burning B.C. gas, which would be much higher. The Pembina Institute (2013) estimates that 24 million tonnes of B.C. LNG would generate 62 million tonnes of CO_2e overseas, bringing the total life cycle emissions to 83.2 million tonnes CO_2e, or 3.47 tonnes per tonne of LNG export.

27 13.3 million tonnes CO_2e (Campbell and Horne 2011).

How will these changes affect First Nations people and the environment?

Table 7 identifies how some of the physical works and activities of the upstream gas sector required in an LNG future may interact with valued components of the biophysical and human environment, creating new and exacerbating existing effects on FNFN territory.

Table 12: Upstream gas industry component — environment interaction matrix

	Investigative use/ research	Well pads	Wells	Pipelines & flowlines	Roads	Seismic lines	Facilities	Gas plants	Compressor stations	Frac sands mines	Dugouts/ H_20 storage	Work camps	Waste mgmt. facilities	Workforce
Increased linear and areal disturbance		x		x	x	x	x	x	x	x	x	x	x	
Increased habitat loss & fragmentation		x		x	x	x	x	x	x	x	x	x	x	
Decreased wildlife numbers and population health		x	x	x	x	x		x	x	x		x		x
Increased water usage		x	x		x					x	x	x		x
Reduced water quality		x	x		x									
Decreased local air quality		x	x		x			x	x	x			x	
Increased GHG emissions		x	x	x	x			x	x					
Increased terrestrial traffic	x	x	x	x	x	x		x		x		x		x
Increased aerial traffic	x			x		x								
Increased pressure on physical and social services					x							x		x
Increased competition for resources				x	x	x								x

Table 12: Upstream gas industry component — environment interaction matrix

	Investigative use/ research	Well pads	Wells	Pipelines & flowlines	Roads	Seismic lines	Facilities	Gas plants	Compressor stations	Frac sands mines	Dugouts/ H_20 storage	Work camps	Waste mgmt. facilities	Workforce
Reduced enjoyment of land	x	x	x	x	x	x	x	x	x	x	x	x	x	x
Increased risk of accidents, malfunctions and contamination		x	x	x	x		x	x	x	x			x	

Adverse impact outcomes of LNG-induced gas extraction from FNFN territory may include:[28]

- Reduced forested area in FNFN territory, increased forest loss and fragmentation of forest ecotypes, high degree of edge effects on forests, associated vegetation and wildlife species reliant upon forest environments;
- Opening up of new, relatively untouched areas in FNFN territory (e.g., portions of the Liard Basin) by roads and pipelines, in particular, reducing their wilderness, ecological and Aboriginal rights practice values;
- Loss or contamination of rare and culturally important plants and ecotypes/habitats;
- Reduced amount of — and functionality of — wetland complexes, critical for moose and other ungulates, furbearers, birds, and fish and other aquatic species harvested by FNFN members, and for the proper functioning of the hydrological system upon which FNFN relies;
- Reduced water quality and quantity and reduced riparian habitat vitality, with attendant risks for aquatic and terrestrial species;
- Disturbance of aquatic and riparian habitat critical to fish and other aquatic species, especially via increased water withdrawals, water contamination, erosion due to pipeline water crossings and road building;
- Increased predation of key ungulate species like moose and woodland caribou, a Species at Risk, especially in relation to long linear developments;
- Introduction of invasive species and displacement of native ones (wildlife and vegetation);

28 See Sections 3.2 and 5.2 in the full Phase 2 report for more discussion on effects to the biophysical and human environments.

- Increasing dust and soil erosion, associated with adverse air, water, traditional use and vegetation effects;
- Large increases in GHG emissions, contributing to climate change;
- Increased electrical power and equipment requirements, inducing additional development and causing a variety of disturbances and risks;
- Increased noise, light and visual, smell and tactile disturbances in the areas in and around physical works and activities, disturbing and affecting the population health of wildlife and disturbing and creating additional alienation from territory — with a variety of demonstrable negative health and well-being effects — of FNFN members;
- Increased access to and use of FNFN territory by non-Aboriginal recreationalists and harvesters, increasing competition for increasingly scarce resources and reducing FNFN enjoyment of its traditional lands and waters;
- Decreased safety (and sense of safety) for FNFN land users, including from harvesting competition, traffic issues, exposure to contamination in air, plants, wildlife and water; and
- Increasing psycho-social impact outcomes for FNFN land users who are facing these rapid changes.

FNFN members in particular have already reported increased land and water alienation, loss of faith in country food sources and associated reduction in country food production, consumption and sharing, reduced ability to meaningfully travel and harvest from the land, reduced enjoyment of traditional territory, reduced opportunities for inter-generational knowledge transfer, an inability or unwillingness to drink water from previously safe locations on the land, and an overarching sense of psycho-social loss and despair associated with these and other losses and their inability to control their own social, economic and cultural futures. [29]

29 These issues are noted in correspondence between FNFN and the federal and provincial governments (e.g., FNFN 2012b; FNFN 2013), the FNFN *Strategic Land Use Plan* (FNFN 2012a), and in many presentations and other outreach efforts by FNFN Chief and Lands Department (e.g., Lowe and Tate 2013).

SUMMARIZING IMPACTS TO FNFN TERRITORY FROM NATURAL GAS EXTRACTION SCENARIOS

LNG-driven shale gas extraction of between 0.49 Mmcf/day and 2.68 Bcf/day could result in the following changes in the three FNFN territory shale basins during the first 20 years of a B.C. LNG export sector:

- Between 356 and 3,995 new hydraulically fractured shale gas wells;
- Development of between 30 and 333 new large industrial facilities in the form of multi-well pad complexes, each covering an average area of nine hectares;
- Between 1,440 and almost 16,000 km of new seismic lines;
- Between 150 and 1,665 km of new roads;
- Development of between 135 and as much as 3,333 km of new pipeline ROW;
- Generation of a total of between 1,635 and 20,900 km of new linear disturbance;
- Generation of total direct areal disturbance of between 30 and 375 km^2, along with a total Zone of Influence of between 104 and 1,277 km^2;
- Between one and five additional large 600 Mmcf/day sales gas plants;
- Additional GHG emissions of between 2.6 and 15.1 million tonnes per year, creating substantial challenges to B.C. meeting its legislated emissions targets;
- Water usage in the hydraulic fracturing process alone of between 11 and 320 billion litres of water (between 31 and 80 million litres per well);
- Use of 1.4 to 16 million tonnes of frac sands, and mining of a substantial amount of it from FNFN territory; and
- Use of 55 million to 1.6 billion litres of chemical additives in hydraulic fracturing processes; and
- Clearing for and construction of hundreds to thousands of other physical works to support the gas sector.

Conclusions and Recommendations

The scope of development required to explore, capture, and transport natural gas to feed B.C. LNG export facilities, as per the stated goals of the Province's *LNG Strategy*, is likely to have unprecedented impacts on FNFN territory.

THE EVIDENCE GATHERED IN THIS STUDY CLEARLY INDICATES that the scope of development required to explore, capture, and transport natural gas to feed B.C. LNG export facilities, as per the stated goals of the Province's *LNG Strategy*, is likely to have unprecedented impacts on FNFN territory. Impacts are expected to be particularly high within the Horn River Basin and the Liard Basin. Among other impacts, without meaningful changes to protection measures for woodland caribou, regional extirpation from many core areas is likely. Given that woodland caribou is both SARA-listed and a preferred harvesting species for FNFN (now subject to an informal FNFN harvesting moratorium), there is a high degree of urgency required in planning a sustainable future for this species.

Some policy recommendations are provided in the full Phase 2 report. Among them are:

- Consideration of the environmental effects of all elements of the LNG export sector — upstream, midstream and downstream — should be properly included during project-specific and sectoral planning and environmental assessments;
- The provincial government in B.C. should more closely examine the upstream cumulative impacts of the burgeoning LNG industry, and cumulative effects in FNFN territory in general; and
- Better planning to protect portions of the Horn River and Liard Basins. Areas of heightened value within these basins are identified in FNFN's (2012) *Strategic Land Use Plan*.

The full Phase 2 report makes a number of specific research recommendations. They include:

- Additional scenario modeling exercises;
- Water studies to establish Aboriginal Base Flow requirements and additional research on the effects of hydraulic fracturing on water quality;
- Traditional use alienation and country food production and consumption studies;
- Gas sector impact footprint studies to establish accurate Zones of Influence; and
- Moose and woodland caribou population health and abundance and gas sector effects studies.

In closing, this study is only a first exploratory step. The findings detailed in this report are indicative of the need for further more detailed work on scenarios of change linking upstream gas development in northeastern B.C. to the B.C. LNG export sector. This study will hopefully open the eyes of other affected First Nations, the people of B.C., industry and the federal and provincial governments to the fact that the domestic LNG export sector *ends*, but does not *begin*, on the B.C. Coast, and that impacts on upstream First Nations must be meaningfully taken into consideration while planning an LNG future.

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