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''Greenwashing gas: Might a 'transition fuel' label legitimize carbon-intensive natural gas development?''

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ABSTRACT

Natural gas is widely considered to be the crucial ''bridging fuel'' in the transition to the low-carbon energy systems necessary to mitigate climate change. This paper develops a case study of the shale gas industry in British Columbia (BC), Canada to evaluate this assumption. We find that the transition fuel argument for gas development in BC is unsubstantiated by the best available evidence. Emissions factors for shale gas and LNG remain poorly characterized and contested in the academic literature, and context-specific factors have significant impacts on the lifecycle emissions of shale gas but have not been evaluated. Moreover, while the province has attempted to frame natural gas development within its ambitious climate change policy, this framing misrepresents substantive policy on gas production. The ''transition fuel'' and ''climate solution'' labels applied to development by the BC provincial government risk legitimizing carbon-intensive gas development. We argue that policy makers in BC and beyond should abandon the ''transition fuel'' characterization of natural gas. Instead, decision making about natural gas development should proceed through transparent engagement with the best available evidence to ensure that natural gas lives up to its best potential in supporting a transition to a low-carbon energy system.

1. Introduction: Natural gas as a transition fuel?

Climate change presents us with the unprecedented challenge of meeting growing energy needs while reducing greenhouse gas emissions produced by our primary energy sources. Key decision leaders hail natural gas as a major contributor to resolve this challenge: the Intergovernmental Panel on Climate Change has called natural gas a ''bridging fuel'' capable of aiding in a transition to renewable sources of energy (2007, Executive Summary, n.p.), and the International Energy Association (IEA) has heralded a golden age of gas (2011). This claim rests on the argument that natural gas is relatively inexpensive, burns cleaner and more efficiently than coal or oil, and is a leading option for backing up intermittent renewable sources with easily dispatchable, scalable generators. These arguments support a growing popular and academic discourse characterizing natural gas as a transition fuel for a low carbon energy system.

However, this transition fuel characterization serves a problematic legitimizing function for natural gas development. While natural gas combustion has environmental benefits over coal or oil in virtually all areas—greenhouse gas emissions, particulate emissions, flexibility and scalability—the impacts of natural gas *production*, including climate impacts, are contested. Unconventional gas resources, such as gas from low-permeability reservoirs such as tight sands and shale, make up an increasing percentage of our global natural gas supply. Indeed, unconventional gas already accounts for nearly half of North American gas production and is expected to make up 64% of North American production by 2020 (EIA, 2011: p. 79). Unconventional sources entail unconventional environmental impacts, and characterizing natural gas as a transition fuel or climate solution may obscure such concerns.

The resource leading this rapid development, shale gas, is the focal point for both the transition fuel discourse and resistance to the industry. While gas was extracted from shale as early as 1821 (Parfitt, 2010), the commercial ''high-volume slick-water hydraulic fracturing'' (fracking) practices many shale gas producers use today, which involve pumping high volumes of water combined with a novel mixture of sand and chemical additives into the well bore, were not deployed at a commercial scale

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until the 1990s. This practice has raised a wide range of concerns, in particular about the scale and impacts of surface and groundwater use; contamination of both air and water by chemicals used for fracking, and health impacts associated with this contamination; landscape-scale impacts of shale gas infrastructure, including habitat fragmentation and degradation; and the climate impacts of expanded fossil fuel use (Davis, 2012; Parfitt, 2010; Pétron et al., 2012). Some such concerns have been substantiated in the peer-reviewed literature[1] while others have not yet been resolved.

Intergovernmental bodies like the IPCC and IEA include caveats about both landscape level risks and climate impacts of developing unconventional gas sources and indicate that further research is necessary (IEA, 2011). However, the momentum of development—and the transition fuel characterization—helps overshadow such concerns, since almost all jurisdictions with cost-effective natural gas resources face pressure to develop them to support economic development.

Decisions about whether to embrace shale gas as a transition fuel are moving forward before policymakers have the answers to key questions. Some jurisdictions such as France, South Africa, the Canadian province of Quebec, and the states of New York and Maryland have placed either temporary or indefinite moratoria on unconventional gas development (IEA, 2011), while other jurisdictions such as British Columbia, Texas, and Pennsylvania are scaling up development of unconventional gas.

We here develop a case study of shale gas development in British Columbia, Canada, to explore the gaps between the transition fuel discourse and best available empirical findings on climate impacts of shale gas development. We first analyze the best available evidence on lifecycle emissions of shale gas and LNG and situate it within the BC context, then explore whether key claims informing the transition fuel discourse are met by substantive policy. Through the BC case, we see how popular and expert discourses that render natural gas a ‘‘clean’’ form of energy are co-opted to legitimize the natural gas industry's interests and a jurisdiction's economic development aspirations at the expense of a considered approach to developing a sustainable energy system.

2. Shale gas in British Columbia, Canada

BC provides a particularly useful case study on the transition fuel discourse and the potential for such framing to ‘‘greenwash’’ development. A poster-child for climate change policy, BC is deeply invested in characterizing its natural gas as a clean transition fuel. The province boasts North America's first significant carbon tax and legislated emissions targets, which require reduction of greenhouse gas emissions by 33% below 2007 levels by 2020, and 80% by 2050 (BC Ministry of Environment Climate Action Secretariat, 2008). Rhetorically, the provincial government has attempted to square its aspirational climate policy and energy development by framing BC as a ‘‘clean energy powerhouse’’ that ‘‘will capitalize on the world's desire and need for clean energy, for the benefit of all British Columbians’’ (Legislative Assembly of British Columbia, 2009).

This discourse has been invoked in the new BC Natural Gas Strategy (BC MEM, 2012a), which opens with statements by the Premier and Minister of Energy and Mines appealing to environmental benefits of shale gas and Liquefied Natural Gas (LNG). The Strategy characterizes BC natural gas as a ‘‘transition fuel’’ and a ‘‘climate solution’’ as a legitimating frame for shale gas development. While BC has a longstanding conventional fossil fuel industry, shale gas is taking the province to unprecedented levels of energy development for export, with commensurately large economic, political and environmental impacts. The largest of BC's shale gas deposits, the Horn River Basin—covering 1.31 million hectares in the northeastern region of the province (Adams, 2011)—may be the largest in Canada (BC Energy Plan Progress Report, 2009), and is thought to be on par with some of the large shale basins in the United States (Parfitt, 2010). The total potential resource in BC remains uncertain: BC's Energy Plan (2007) claimed 250 trillion cubic feet (tcf) of undiscovered shale gas, while more recent Ministry of Energy and Mines (BC MEM) publications suggested up to 1000 tcf of gas (BC MEM, 2009).

While other BC reserves have not yet been evaluated for current marketable potential, the Horn River Basin alone is thought to contain 78 tcf of marketable gas in the medium case estimate (National Energy Board and BC MEM, 2011). For reference, BC produced just over 1.2 tcf in 2010 from its conventional and unconventional resources combined (BC Stats, 2011: p. 4), translating to 65 years worth of marketable gas in the Horn River Basin alone at current rates of production. However, provincial gas production is expected to rise to 3 tcf by 2020 (BC MEM, 2012a). Increases in production are already underway: shale gas and closely related tight gas[2] wells now comprise 50% of BC gas production (BC MEM, 2012a), up from 39% of BC's total gas production in 2008 (Adams, 2010). BC played host to the world's largest hydraulic fracturing operation—nearly four times larger than any similar project in North America—completed by Apache Corporation in the Horn River Basin in 2010 (Apache Corporation, 2010). The large scale of BC's shale gas resources and rapid pace of development magnify questions facing other jurisdictions with natural gas resources, questions the province must reconcile with its aspirational climate change and clean energy policy.

What, then, is the potential for BC shale gas and LNG development to live up to this characterization?

3. Transition fuel potential of BC shale gas: Greenhouse gas emissions of shale gas

This section first examines the best available science on production and lifecycle emissions impacts of shale gas and LNG development, before turning to geological, geographical and market contexts specific to the BC shale gas and LNG development.

Like many jurisdictions accelerating shale gas development, BC's appeals to shale gas as a ‘‘transition fuel’’ and a ‘‘climate solution’’ assume emissions benefits of natural gas combustion over emissions-intensive alternatives (BC MEM, 2012a):

> Natural gas is the world's cleanest-burning fossil fuel. B.C. exports of liquefied natural gas (LNG) can significantly lower

[1] For example, in 2010 the United States House of Representatives Committee on Energy and Commerce (2010: p. 1) reported that between 2005 and 2009, fracking fluids used by American oil and gas operators included 29 chemicals that were known or possible human carcinogens, regulated under the Safe Drinking Water Act, or listed as hazardous air pollutants under the Clean Air Act. Osborn et al. (2011: p. 2) found that hydraulic fracturing has caused methane contamination of drinking water supplies in New York State—a potential asphyxiation, explosion and fire hazard. Scientific studies on subsurface fracking fluid contamination are lacking, but the EPA concluded in a recent investigation that the most likely explanation for groundwater contamination near Pavillion, Wyoming was inorganic and organic constituents associated with hydraulic fracturing (EPA, 2011a), although the report cautions that further investigation is needed to improve the confidence of the study's result (EPA, 2012).

[2] The Montney Play is classified by Adams (2010) and others as tight gas, but the National Energy Board and a recent report by The Pembina Institute (Horne, 2011) characterize this formation as shale since certain geological characteristics are more typical of shale formations (Horne, 2011: p. 5).

> global greenhouse gas emissions by replacing coal-fired power plants and oil-based transportation fuels with a much cleaner alternative. LNG development in B.C. can have lower lifecycle greenhouse gas emissions than anywhere else in the world by promoting the use of clean electricity to power LNG plants. B.C.'s LNG industry will contribute to our leadership in the transition to a low carbon global economy (BC MEM, 2012a: p. 2).

While such reasoning is used to legitimize shale gas development, there remains a high degree of scientific uncertainty concerning the greenhouse gas emissions of shale gas.

The scientific discourse remains contested, with camps coalescing around higher and lower emissions factors achieved through different methods of measurement. The International Energy Agency (2011) finds that shale gas produces life-cycle emissions between 3.5% and 12% higher than conventional natural gas over a 100-year timeframe (in the low estimate gas is flared while in the high estimate it is vented). At the lower end are recent models from Shell Global Solutions, which find that shale gas exhibits a 1.8–2.4% increase over "wells-to-wires" lifecycle emissions from conventional gas when used for electricity generation (Stephenson et al., 2011). This study further finds that emissions intensity is strongly affected by the ultimate recovery (the volume of gas produced by a well) but estimates of this variable exhibit a considerable range of between 1 and 3 bcf for shale wells, which will affect relative emissions especially as drilling moves on from the most productive wells. At the higher end of estimates, the first peer-reviewed study on fugitive emissions from shale gas production, Howarth et al. (2011), generated significant controversy by suggesting that over a 20-year timeframe, greenhouse gas emissions from shale gas are typically 20–100% higher than coal, and over a 100-year time frame they are similar to coal (Howarth et al., 2011). The timeframe of measurement is significant because of the higher climate sensitivity of methane as a greenhouse gas over a 20-year timeframe: the 20-year Global Warming Potential of methane is 72 times that of CO_2 according to IPCC AR4 (2007), and may be as high as 105 times greater according to recent research (Shindell et al., 2009). Critics have taken issue with various assumptions in the Howarth et al. study, identifying it as an "outlier," and have referred to these higher estimates as "alarmist" (Stephenson et al., 2011).

Why are these estimates contested? In part, important input variables remain uncertain. For example, we can look to the estimates on so-called "fugitive emissions". Howarth et al. (2011) estimate methane emissions of 2.2–4.3% of total gas volume from upstream and midstream (processing) combined. Multiple recent low-estimate studies (e.g. Jiang et al., 2011; Cathles et al., 2012; Venkatesh et al., 2011) use the input variable of fugitive emissions equal to 2.2% of total production, based on EPA estimates (2011b), in several cases without including a sensitivity analysis for this variable. Meanwhile, the only peer-reviewed study that has actually measured landscape-level emissions from a natural gas field found fugitive emissions in line with higher rather than lower estimates: a joint study by the National Oceanic and Atmospheric Administration (NOAA) and the University of Colorado measured emissions directly using air quality testing equipment over tight sands natural gas fields near Boulder, Colorado, and measured a 2.3–7.7% loss of methane to the atmosphere due to fugitive emissions (Pétron et al., 2012), with a best estimate of 4%. Pétron et al. (2012) emphasize that these estimates are subject to a high degree of uncertainty, but if reproducible elsewhere, these findings would suggest higher lifecycle emissions for shale gas.

We therefore raise the concern that modeling in this field is susceptible to a false sense of independent replication. Lifecycle analysis is only as good as the assumptions that go into it, and there remains a high degree of uncertainty about many input variables that characterize shale gas emissions. This uncertainty does not prevent many studies and models from relying on the same uncertain inputs as outlined above. New findings may demand the recalculation of many apparently independent models, undermining the immature sense of consensus that had begun to develop.

This brief overview characterizes the (high) degree of uncertainty in our understanding of the emissions profile of shale gas. Studies generally have agreed that shale gas exhibits a higher emissions factor than conventional gas, but discrepancies exist between bottom up modeling results and actual field measurements (which remain limited), and between various lifecycle analyses. These discrepancies result from differing assumptions about various input variables including: venting, flaring and recovery practices; other fugitive emissions; the longevity of well production; end use application of gas, such as generation versus heating; the factor used for global warming potential of methane; the time horizon of global warming potential; and assumptions about the composition of shale gas, such as the presence or absence of formation CO_2.

Such uncertainty in input variables and in subsequent lifecycle emissions estimates for shale gas suggests that further research is required before we can accurately characterize shale gas as a bridge to a cleaner energy system. However, even if further research is conducted, we are mindful of the limited ability of the best available science to measure fugitive emissions by their very nature.

Given the high degree of uncertainty, even the best available studies remain limited in their ability to inform responsible energy policy. We are not satisfied that currently available information justifies the transition fuel characterization of shale gas in BC.

4. BC-specific factors shaping emissions from natural gas production

Conditions specific to the BC context will affect the relative emissions benefits of shale gas over alternatives. Most significantly, geological characteristics of some major BC shale basins exacerbate production-related CO_2 emissions: the Horn River Basin exhibits unusually high formation CO_2 with an average of 12% of raw gas, but varying between 8% and 19% of the total volume depending on depth (NEB, 2009; National Energy Board and BC MEM, 2011). This CO_2 must be separated from pre-processed gas and vented to the atmosphere to produce pipeline quality gas that contains less than 1% CO_2 by volume (Venkatesh et al., 2011). The release of this volume of CO_2 will make it extremely difficult for BC to meet its climate change targets:

> If B.C. is to achieve its GHG emission target while pursuing shale gas development, it will need to reduce emissions throughout the economy by almost 50% from where they would otherwise have been in 2020 as its population, building stock, industrial sector, and number of vehicles grow over the next decade (Jaccard and Griffin, 2010: p. 5).

Horne (2011) notes that, given the average 12% formation CO_2 in the Horn River Basin, gas produced from this basin is expected to result in an 86% increase in emissions from formation CO_2 per unit of gas over historical gas production in BC (gas produced in 2005 and earlier, prior to significant production of shale gas). The much lower formation CO_2 in the Montney Basin is expected to result in a 22% decrease in emissions from formation CO_2 per unit of gas over historical production. Thus, overall emissions related to formation CO_2 in BC shale gas production will depend on the proportion of gas being produced in each basin. Estimates of future production from either basin vary widely: for example, in December, 2010, BC Hydro estimated production in the Horn River Basin would peak of 2400 MMscf/day. By February of 2012, BC Hydro had revised its middle scenario to an estimate of more than double that figure, at a peak of 4900 MMscf/day (BC Hydro, 2012).

While there are some proposals to sequester a portion of the additional formation CO_2 from the Horn River Basin (see Jaccard and Griffin, 2010), the viability of this idea has not yet been evaluated in depth. Whether carbon capture and storage, conversion to methanol, or other possibilities could cost-effectively address these emissions is unclear. This is a pressing question given the marginal competitiveness of the remote BC industry (Adams, 2010). Therefore, short of an unprecedented deployment of carbon capture and storage technology BC's shale gas does not immediately live up to the hopes of a ''transition fuel'' on the production side.

5. End-use applications of BC shale gas

In light of these production-side concerns, proponents instead appeal to lifecycle emissions benefits of BC gas. However, given end-uses accessible to the BC market, these impacts also remain contested. BC currently exports 65% of its natural gas to Alberta and the Pacific Northwest and consumes 15% domestically. The remaining 20% is attributed to total field losses including flaring, metering differences and loss during distribution and export (BC Stats, 2011). BC's gas producers and distributors may be adding Asian markets to this list with new Liquefied Natural Gas shipment capabilities recently approved and supported in policy directions outlined in the new BC Natural Gas Strategy (BC MEM, 2012b).

Domestic market applications, at present, do not substantiate the transition fuel argument for BC shale gas development. In other jurisdictions, particularly the United States, characterizations of shale gas as a transition fuel have emphasized applications in combined cycle gas turbine electrical generation to replace older generation coal-fired generation. They have also looked ahead to increasing use of natural gas generation to back up intermittent renewable sources (International Energy Agency, 2011). The BC government and industry have not appealed to these arguments domestically, as BC already enjoys low-emissions electricity production that is incompatible with fuel switching to natural gas given current greenhouse gas-related requirements in the province. 90% of BC's electricity currently comes from clean or renewable sources, primarily large ''legacy'' hydroelectric projects, and the BC Energy Plan (2007) mandates that clean or renewable electricity continues to account for at least 90% of electricity generated in the province. BC's Energy Plan (2007) suggests that new power plants must have zero net emissions, and that by 2016 all existing thermal plants must also have zero net emissions. BC can use its large reservoirs in the hydroelectric system for load balancing, limiting the need for natural gas to act as a scalable and efficient fuel to back up intermittent renewable sources.

For other domestic applications, the BC Natural Gas Strategy (BC MEM, 2012a) advocates expanded use of BC gas for heavy trucking and BC's ferry fleet, as well as development of value-added industries like methanol and fertilizer production, but no technical evaluation of such applications is available to date. Barring unprecedented growth in these novel applications, the domestic market is unlikely to absorb significant additional quantities of natural gas. The BC distributor, Fortis BC (previously Terasen Gas) projects flat domestic demand for the next 20 years, and identifies a wide variety of barriers to market expansion in BC, including the fact that BC's low electricity prices dissuade customers from using natural gas for applications like home heating (Terasen, 2010). BC's current climate policies and energy demand projections make it unlikely that much of the increased gas production will be absorbed by demand from within the province, so industry and the province are looking to other markets where prices are significantly higher.

6. Greenhouse gas emissions of BC liquified natural gas

With limited domestic potential, plans are rapidly developing for LNG export to absorb the bulk of BC's increased production capacity (BC LNG Strategy, 2012b). Plans are underway to construct new LNG terminals near Kitimat, BC on the central coast of the province, by 2020. The first of these, Kitimat LNG Corporation, received federal approval to export LNG in 2011. Its operating plans, available at http://www.kitimatlngfacility.com, are to ship 5 million tonnes of LNG, or 244 bcf per year. LNG has a central role in the transition fuel narrative currently supported by the provincial government. Indeed, recent policy documents and press releases heavily emphasize the environmental benefits of LNG export rather than drawing attention to the (more controversial) upstream impacts of shale gas development (BC MEM, 2012a). Nations across Asia and potential LNG export partners do rely heavily on coal for electricity generation, and in the best-case scenario, BC LNG could help reduce their dependence on coal.

However, questions remain about whether LNG produced from unconventional gas can bridge to a sustainable energy supply, or will instead commit jurisdictions to technical lock-in of emissions-intensive energy infrastructure. LNG adds liquefaction, tanker transport, and regasification to the life-cycle of natural gas, resulting in higher GHG emissions. There remains a dearth of research in this area, and available models of LNG emissions factors return a wide range of estimates depending on what input variables and assumptions are used. We have found no research that characterizes the cumulative emissions associated with liquefying unconventional sources such as shale.

The only available studies to date have compared lifecycle emissions of LNG and domestic pipeline gas as one stage in larger modeling activities.

We here describe the best available numbers to characterize the degree of uncertainty and explore, using available estimates, the potential for additional emissions associated with LNG production to compromise the ability of BC shale gas to deliver as a climate solution. The most recent study available at the time of submission, Venkatesh et al. (2011: p. S14) models liquefaction, shipping, and regasification[3] as contributing 12.3 g CO_2e/Megajoule (MJ) to total lifecycle emissions of 70 g CO_2e/MJ in the mean case, an addition of approximately 18%. Jaramillo et al. (2007: p. 6293), the most recent peer reviewed scientific study directly comparing LNG, conventional gas emissions, and coal for electricity production finds life-cycle emissions of LNG to be 21.9% higher than domestic natural gas, with 1600 versus 1250 lb CO_2 equivalent per megawatt hour (MWh) of electricity generated in the midpoint case. (Conversion to CO_2 emissions per MWh means the units are directly comparable). They found the life-cycle emissions of coal to be 29.5% higher than LNG, with a midpoint life-cycle emissions factor of 2270 lb CO_2 equivalent/MWh (Jaramillo et al., 2007: p. 6293). However, this study used 1996 Environmental Protection Agency (EPA) methane emissions estimates, and the EPA now says that ''emissions estimates from the EPA/GRI study are outdated and potentially understated for some

[3] We draw on the Venkatesh et al. (2011) findings on LNG liquefaction, gasification, and transport emissions specifically rather than lifecycle emissions, because their study compares domestic US gas (of which unconventional makes up a large share) with imported LNG (which they assume to have lower upstream production emissions as a result), so its findings on lifecycle emissions are ill-suited to describe the BC LNG development where shale gas will be converted to LNG.

emissions sources'' (EPA, 2010: p. 8). Therefore, the numbers provided by Jaramillo et al. (2007) likely underestimate LNG emissions and overestimate the benefits of LNG over coal, as methane plays a significant role in the GHG emissions of natural gas and only a small role in the life-cycle emissions of coal.

While midpoint estimates are useful metrics for comparison, the range of emissions also matters, and even with an estimate that may be low, the authors found that ''the range of life-cycle GHG emissions of electricity generated with LNG is significantly closer to the range of emissions from coal than the life-cycle emissions of natural gas produced in North America'' (Jaramillo et al., 2007: p. 6293). The upper bound estimate for life-cycle emissions from LNG was only 6% lower from the upper bound estimate for life-cycle emissions from coal (2400 lb CO_2 equivalent/MWh for LNG and 2550 lb CO_2 equivalent/MWh for coal). If emissions factors for shale gas and LNG are closer to the higher ranges estimated in various lifecycle assessments, their life-cycle GHG emissions may not compare favorably to coal-fired power generation, let alone support a bridging fuel argument for development.

We find this existing evidence inadequate to justify the characterization of LNG derived from BC shale gas as a clean transition fuel or climate solution, especially when such LNG is produced from shale gas, which may contribute higher upstream emissions. Further study is urgently required to fill gaps in the literature and better characterize the lifecycle emissions of LNG, as are updated models that include sensitivity to the use of unconventional fuels like shale gas for LNG production.

Further case-specific quantitative analysis will also be required to consider how context-specific variables will affect lifecycle impacts. For example, the discourse in BC promotes shale gas and LNG industry as contributing to a global green economy, including displacing emissions-intensive fossil fuels such as coal in Asia (BC LNG Strategy, 2012b). However, there have been no attempts to consider seriously how LNG from BC would fit into the Asian energy context, and the degree to which BC gas would actually displace more emissions-intensive fossil fuels remains unclear.

Context-specific analysis is also required to inform policy to engender climate-friendly applications for gas development. For example, there is a reason for optimism that BC LNG will have substantially reduced emissions during the liquefaction stage compared with LNG produced in other jurisdictions, with plans in place to electrify two of the three proposed BC facilities using low-carbon sources (BC LNG Strategy, 2012b). This is significant, because 71.6% of the additional emissions associated with LNG production (over pipeline gas) come from the liquefaction stage, with liquefaction amounting to 8.8 g CO_2e/MJ of a total of 12.3 g CO_2e/MJ between liquefaction, shipping and regasification of LNG (medium estimates in Venkatesh et al., 2011). At present, our findings on the relative emission costs and benefits from BC LNG are inconclusive: although electrification has the potential to substantially reduce life-cycle emissions, given the uncertainty in the estimates overall, it is unclear by how much.

7. Continental export markets

LNG development remains in early stages, with approval processes still underway for all proposed developments, and questions remain about the viability of this industry. Investors in the Kitimat LNG project (including Apache Corporation, EOG Resources Canada, Inc., and Encana Corporation) clearly believe such LNG production will be profitable, and the BC provincial government has endorsed LNG as a key component to develop the BC shale gas industry (BC MEM, 2012b). The only existing LNG export terminal in North America, Alaska LNG, closed this year when it was unable to secure sales in an increasingly competitive marketplace. While the proposed Kitimat LNG facility will be larger and will have more negotiating power, this closure does raise questions about the economic viability of multiple competing LNG plants on the BC coast (BC Stats, 2011). However, if LNG development does not go ahead as planned and cannot absorb BC's increased production, BC does have diversified market access and can export its increased shale gas production as pipeline gas.

The leading continental market capable of absorbing additional capacity is the adjacent province of Alberta, which both faces a declining domestic gas production and is the gateway to the transcontinental pipeline market. 43% of BC capacity is currently exported to Alberta, and the BC Natural Gas Strategy (BC MEM, 2012a) includes a pledge to maintain current markets. Alberta exports its own natural gas from the Western Canadian Sedimentary Basin, within which BC shales are also found, and was responsible for over 80% of Canadian exports to the US in 2010 (BC Stats, 2011: p. 5). However, Alberta's natural gas production is falling steadily while BC's is rising (Terasen, 2010: p. 14). Exports to Alberta from BC are projected to rise to make up for the province's declining domestic production, and work is underway to increase capacity in the pipeline system to carry gas to Alberta (Terasen, 2010).

Here, natural gas is unlikely to fit the transition fuel rhetoric promoted by BC industry advocates. Why? Natural gas plays a critical role in the Albertan economy as an input for its booming bituminous sands industry: ''The Alberta oil sands currently consume around 1.0 Bcf/day of natural gas and this amount is forecast to more than double by 2017'' (Terasen, 2010: p. 14). To put this figure in context, BC currently exports 0.96 bcf/day to Alberta (calculation using data from BC Stats, 2011). In-situ production of bitumen from Alberta's oil sands is the biggest and closest consumer for BC's shale gas industry, and if BC's industry grows as quickly and significantly as proponents project, the only Canadian consumer currently forecasting a concurrent growth in natural gas demand is Alberta. By 2030, the oil sands are forecast by the IEA to consume 22% of all natural gas consumed in Canada, versus 12% in 2006 (McCallion, 2010, n.p.). In 2010, approximately 8.9% of all gas produced in Alberta went to fuel bitumen production (Government of Alberta, 2011).

Alberta will also grow in importance as BC's largest existing export market, the Pacific Northwest (PNW), is expected to shrink and appears unlikely to absorb significant increased capacity (Terasen, 2010). While natural gas in the PNW may play a role in offsetting coal-fired generation, here BC gas here competes with increased American production: the Energy Information Administration (EIA) projects increased gas production in the American Rocky Mountain region (the alternative source for the Pacific Northwest) due to increased tight sands and coalbed methane production, and projects an overall decline in imports from Canadian after 2018 (EIA, 2011: p. 80). Additionally, current infrastructure cannot accommodate increased gas exports to the PNW (Terasen, 2010: p. 175).

BC, like all jurisdictions, holds limited responsibility for and control over what happens beyond its jurisdictional boundaries, but appealing to beneficial uses of natural gas beyond its borders forms a central argument for developing BC shale gas for environmental reasons. The BC Natural Gas Strategy (BC MEM, 2012a) promises to collaborate with other jurisdictions to raise the level of ambition on using natural gas to bridge to a cleaner energy system. It remains to be seen whether this laudable goal can be met with substantive policy.

8. Is BC regulation living up to ''transition fuel'' characterization?

While inter-jurisdictional cooperation to reduce emissions remains in early stages, BC does appeal to other policy successes in its argument for shale gas development in the recent BC Natural Gas Strategy (BC MEM, 2012a). This section will explore substantive policy direction to date in BC to identify the degree to which the "transition fuel" and "climate solution" discourse promoted by the BC provincial government is supported by action.

We take BC's current policy on venting and flaring of gas during production as an illustrative example. This example suggests that substantive policy has not kept pace with transition fuel rhetoric. It further indicates that current reporting practices obscure relevant data, limiting our capacity to fully evaluate the potential costs—as well as prospective benefits—of shale gas and LNG development. Flaring and venting account for a significant portion of the lifecycle emissions of shale gas, and reductions in emissions from these sources are crucial if BC shale gas is to be considered a transition fuel. Flaring refers to the controlled combustion of gas, while venting is the practice of simply releasing gas instead of combusting it. The Natural Gas Strategy identifies flaring gas as an area of considerable progress and a regulatory success story: "The Oil and Gas Commission reported in 2010 that the interim goal to cut flaring in half by 2011 had already been achieved" (BC MEM, 2012a: p. 11).

This claim suggests that major strides have been made in reducing flaring during natural gas production in BC. However, we find that this key claim informing the BC provincial government's transition fuel discourse is not credible. Contrary to the claim, the BC Oil and Gas Commission (OGC) report cited by the Strategy states only that *the routine flaring of solution gas* has been reduced by 60% since the baseline year of 2006, while annual flared volumes of all gases (including solution gas) declined by 26% over the same period. Solution gas is not particularly relevant to shale gas production: it is the gas that is co-produced with oil or other liquid hydrocarbons, and in BC, occurs predominantly at oil producing wells and batteries (OGC, 2011b). Even then, the claimed 60% decrease in the volume of solution gas flared is less impressive than it is presented to be, since oil condensate production in BC, the major source of solution gas, decreased by 17.3% between 2006 and 2010 according to the Oil Production Report, resulting in a reduction in flaring per unit of oil and condensate produced of 49.6% (BC MEM, 2011).

A second concern about claims to success in regulating flaring relates to the definition of routine flaring. While the 2007 BC Energy Plan indeed commits to the elimination of routine flaring by 2016, routine flaring is defined as "the continuous flaring of gas that is not required for safety or environmental purposes and is economical to conserve" (OGC, 2011a: p. 6). While there is a −$50,000 net present value (NPV) threshold for solution gas (i.e., solution gas must be conserved where the cost to the producer is less than $50,000), there is no such threshold for reducing flaring from natural gas production: the only requirement is that gas should be conserved rather than flared where it is economical to do so (where there is a positive NPV in conserving the gas) (OGC, 2011a).

Delving deeper, we find further cause for concern as the OGC reports fail to transparently and comprehensively report the emissions from flaring in the BC gas industry. For example, the OGC reported 2010 reductions in flared solution gas in absolute volumes, while the same document reports reductions in natural gas flaring in intensity-based terms (rather than in terms of absolute volumes). This has the effect of emphasizing reductions—and minimizing increases—in gas flaring (OGC, 2011b: p. 6). The report also provides reductions in flaring related to natural gas using a different baseline year, 1996, rather than the 2006 baseline used to refer to solution gas, confounding attempts to compare changes in contributions to flared volumes of gas from different sources.

More transparency and better data are needed to draw strong conclusions. At present, the BC Natural Gas Strategy overstates the actual rate of reduction in flaring during natural gas production in order to justify the labeling of BC natural gas as a "climate solution" (BC MEM, 2012a). While we find that claims about reduced flaring of gas are not substantiated by the best publically available data, further concerns over transparency and data availability surround the lack of reporting on venting of gas during production. As noted earlier in this study, venting methane, with its high (and still contested) global warming potential, directly to the atmosphere can present a major source of emissions in the lifecycle of natural gas. The OGC's 2011 report states:

> Venting is not an acceptable alternative to flaring and is only allowed where the operation may be conducted safely and flaring or incineration is not practical (OGC, 2011b: p. 7).

However, what constitutes "practical" under the OGCs guidelines is not defined in this document. The OGC guidelines require producers of natural gas in BC to flare or incinerate non-conserved gas (rather than vent it) if volumes and flow rates are sufficient to support stable combustion (OGC, 2011a), but total volumes of gas vented during production and processing remain unclear as the annual OGC flaring, venting and incineration reports only provide figures for flared volumes of gas, and not for vented gas. Additional transparency from the OGC on reporting of these volumes would allow for further quantification of lifecycle emissions of BC natural gas and aid us to begin to substantiate the transition fuel discourse.

Claims about flaring and venting provide just one example of where the transition fuel discourse and BC policy are not consistent. There are other major elements of the transition fuel discourse that are not supported by existing policy frameworks. These include the prospect of carbon capture and storage to mitigate shale gas emissions, as well as the electrification of LNG liquefaction with low-carbon energy sources, both of which are referred to at length in the BC Natural Gas Strategy (2012a). If either of these measures fails to materialize, the touted emissions benefits of LNG produced from BC shale gas could disappear. Allowing industry to expand rapidly without these frameworks in place may make it difficult for industry actors to assess whether the economics of shale gas production can bear the cost of these additional measures while remaining profitable, particularly given competitiveness constraints such as the remoteness of the industry, global competition in the LNG market, and American competition for continental markets (Adams, 2011; McCallion, 2010).

9. Discussion and limitations of this study

This section will discuss implications of the BC case as outlined above and identify areas for further research. In BC, we find a disjuncture between the transition fuel discourse promoted by the shale gas industry and government and the present on-the-ground conditions of the BC gas industry. Firstly, regulation and other policy approaches have not kept pace with attempts to frame BC shale gas as a transition fuel. Secondly, there remains significant uncertainty in the relevant science, particularly the emissions factors for shale gas and LNG. The latter disjuncture indicates that a generic characterization of natural gas as a transition fuel is problematic, as it may legitimize development that will fail to deliver emissions reductions and result in other attendant environmental impacts. Further study is required to explore whether substantive regulation could close this gap between transition fuel framing and on-the-ground industry conditions.

We point to the following as key areas requiring further quantitative analysis in the BC case:

- How will impacts of BC industry development change depending on leading options for end-use-applications in Asian export markets? Will the gas produced displace coal-fired electricity production?
- How substantive are BC efforts to reduce environmental impacts of the industry? What are the quantitative impacts of industry electrification and how credible are appeals to the potential of carbon capture and storage?
- How will shale gas and LNG development affect the climate profile of the BC energy system overall? Increased demand for clean electricity to support the LNG industry in BC will likely lead to the construction of major new hydro-electric facilities. Would the climate benefits of exporting clean electricity outweigh the benefits of LNG export?
- Is an environmentally sustainable BC shale gas and LNG industry economically viable? If the industry is marginal, will the costs of imposing environmental regulation be politically infeasible?

In the absence of such research, we argue that claims that BC shale gas will be a ''climate solution'' and ''transition fuel'' as promoted in the BC Natural Gas Strategy (BC MEM, 2012a) are unsubstantiated, and amount to greenwashing. We argue that the onus is now on the provincial government and BC industry to substantiate this characterization of shale gas and LNG as a ''climate solution'' and evaluate the degree to which substantive policy can bring actual conditions in line with aspirational discourse.

10. Conclusion

The BC case speaks to the pressing need for further independent empirical assessments of the upstream gas industry to guide decision making, policy and regulation to ensure natural gas development can deliver on its potential as a climate-friendly fuel. There are still major gaps in quantifying the lifecycle emissions of LNG, and the upstream emissions and fugitive emissions from shale gas production. Additional direct measurements of emissions associated with unconventional gas production are required for more credible lifecycle emissions models. For example, further studies are needed to determine whether the levels of fugitive methane detected over gas wells in the Colorado Front Range in Petron et al. (2012)—a single study—are accurate, or typical of unconventional gas development. More transparent participation by industry in data disclosure and analysis may also improve confidence in estimates of lifecycle emissions from shale gas.

BC also indicates to us that the capacity of natural gas to contribute to a cleaner energy system will be context dependent. Specifically, it will depend on the characteristics of the resource, such as formation CO_2; the markets available to the industry, such as LNG and export to Alberta; and regulatory measures undertaken to limit impacts, such as venting and flaring policy, requirements to use CCS and electrification of LNG facilities.

While uncertainty and context-specific considerations prevent us from endorsing the ''transition fuel'' characterization, they also prevent us from dismissing the possibility that this assessment may change in the future as better information becomes available and claims can be substantiated. Under some scenarios, BC shale gas may have the potential to reduce emissions—for example, if emissions from upstream production are controlled, if additional measures are taken to reduce lifecycle emissions (such as electrification of LNG facilities with low-emissions sources), and if the gas is actually used to displace higher-emitting fuels such as coal.

Nonetheless, there are also broader questions beyond the scope of this study about the role of natural gas as a climate solution that have bearing on the ''shale gas as transition fuel'' discourse. Regardless of the relative benefits of LNG and shale gas over coal, additional investment in gas infrastructure may serve to delay—rather than bridge—to truly low carbon sources of energy, in terms of displacing investment in nuclear or renewables. The IEA baseline scenario in its report, the Golden Age of Gas, sees natural gas replace demand for other fossil fuels, such as coal, but also some lower-emissions sources, such as nuclear, setting CO_2 emissions on a trajectory to stabilize at 650 ppm, and resulting in a likely global average surface temperature rise of more than 3.5 degrees (IEA, 2011). Committing to continued fossil fuel development also commits us to path dependent infrastructure, both physical and institutional, and means making choices that extend far beyond the scope of weighing relative emissions factors.

We argue that, at present, policy makers should abandon the transition fuel characterization of natural gas in favor of improved transparency with regard to the high degree of uncertainty: rather than championing or vilifying natural gas, we should instead be asking: ''what types of natural gas, under what conditions, can contribute to a more sustainable energy future?''

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