MINISTRY OF ENVIRONMENT
MEETING INFORMATION NOTE

September 24, 2013
File: 280-20
CLIFF/tracking #: 198380

PREPARED FOR: Honourable Mary Polak, Minister of Environment

DATE AND TIME OF MEETING: October 8 at 11:15 a.m., Exec Boardroom, PVO

ATTENDEES: Minister Polak and Dr. James Tansey, CEO of Offsetters

ISSUE: Liquefied Natural Gas (LNG) and the opportunity to innovate for climate solutions.

BACKGROUND:

The Province of British Columbia has emerged as a global leader in climate action and has legislated reduction targets for greenhouse gas (GHG) emissions. There have been concerns by the public and stakeholders that the development of an LNG sector in BC could have significant impacts on reaching the Province's legislated GHG reductions targets.

Dr. James Tansey is the CEO of Offsetters Climate Solutions (Offsetters) and a respected professor at the University of British Columbia. He has recently spoken to LNG proponents, such as Shell, Petronas and BC, about the role offsets could play in the development of LNG facilities. Industry has engaged with him on this topic due to pressure from their stakeholders to mitigate GHG emissions from proposed future LNG operations.

Offsetters was established in 2005, by Dr. James Tansey. It is the largest carbon management company in Canada and is one of the largest in North America, providing a dependable source of high quality offsets. They help organizations and individuals understand, reduce, and offset their climate impact. The Offsetters team provides expertise in greenhouse gas measurement, climate change science and policy, renewable energy and energy efficiency, and carbon finance.

DISCUSSION:

Dr. James Tansey has the expertise to demonstrate opportunities to link BC's investment in the LNG sector with the broader innovation agenda within the Province. Offsetters is: a knowledgeable and an experienced GHG offset provider with a strong international presence and record of sales to PCT; respected by First Nations and ENGOs as a trusted advisor on GHG policy to all parties; familiar with the Cleantech sector and tech development cycles; understands investment needs and is an ally in promoting the green economy; and, they develop and implement leading edge carbon projects to lower costs and advance BC towards it's emission targets.

Based on Offsetters experience and interactions with the LNG sector they have identified some key suggestions for the Province to consider for addressing potential LNG GHG impacts. Briefly these include:

s.13, s.17

SUGGESTED RESPONSE:

s.13

Attachments: 198380 incoming letter addressed to Premier Clark

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DMO	VJ	Oct 3/13
ADM	JM	Sept 27/13
ED	TL	Sept 25/13
Author	DB	Sept 24/13

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TEAM OFFICIAL SUPPLIER

August 29, 2013

Premier Christy Clark
740-999 Canada Place,
Vancouver, BC,
V6C 3E1

Dear Premier Clark,

The Province of British Columbia has emerged as a global leader in climate policy over the last five years and the potential for the development of an LNG sector that can produce fuel at a scale that will have significant impacts on greenhouse gas emissions in Asia and N. America is the next chapter in that story.

I am writing to request you consider a number of key suggestions that will ensure that, as a Province, we can genuinely claim to host the greenest natural gas sector in the world. I think there are some key opportunities to link our investment in the LNG sector with the broader innovation agenda within the province. While I don't claim to represent the clean technology sector, my company is the largest carbon management company in Canada and one of the largest in North America. We've been able to achieve some of this growth due to the forward thinking policies of this government. We have established the two largest forest carbon projects in the world, one of which is in BC, and we work with global leaders on climate policy including lululemon, Aimia, Dow Industries and Harbour Air, the world's only carbon neutral airline. We've taken what we learned from the carbon neutrality programme during the 2010 Olympics to Sochi and we will be taking those lessons to Brazil in 2016.

As we look out at the development of the LNG facilities it is important to recognize that while the carbon tax is a highly progressive policy, it does not reduce emissions significantly from large-scale energy intensive operations: there is still much more carbon dioxide in the atmosphere once the facilities are built. The carbon tax places a price on carbon that encourages innovation, but it can't eliminate carbon dioxide from electric or direct drive LNG facilities. The only way to deal with those additional emissions is to build on the robust offset policy laid out in the BC Emission Offsets Regulation (BCEOR).

While other jurisdictions in North America, including Alberta, Quebec and California have offset regulations in place, our system offers the highest quality assurance and the widest array of project types. BC has been a leading innovator in offset policy through the creation of protocols in forestry, fuel switching and energy efficiency, to name a few. In the process of delivering on the government's carbon neutrality obligations, these projects have leveraged hundreds of millions of dollars of investment into technology, projects in truck transportation and the forestry sector. Notwithstanding the misguided and poorly executed review of the Auditor General—whose finding your government rightly rejected—we have a regulatory system that is world class.

As the LNG proponents have begun to develop their business cases in the Province, we have spoken to them at length about the role of offsets in the development of LNG facilities. We have been surprised by the willingness of companies like Shell, Petronas and BG to embrace offsets and it is clear that they face significant pressure from their shareholders and other stakeholders to mitigate emissions from their operations. We recently ran an RFP to sell offsets on behalf of our project owners in BC and the five largest

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proponents expressed a strong interest in investing in offset projects immediately, as long as government provides the appropriate regulatory guidance. That purchasing activity will translate into significant revenues within the province, well ahead of revenues from LNG sales as the proponents will seek to manage costs by building up offset inventory. These investments in rural and First Nations communities can only help to build on their social license to operate.

Building on our experience in the sector and our interactions with the industry, my key suggestions are as follows:

s.13, s.17

At this stage in the development of our LNG resources, I urge you to provide the clarity that the proponents are seeking. They are able and willing to innovate in respond to clear regulatory signals. It is that private sector innovation that will ensure we maintain our position as a global leader in climate policy.

Yours sincerely,

Dr. James Tansey

President and CEO, Offsetters Climate Solutions

CC: Dan Doyle, Ministers Polak, Bennett, Coleman and Wilkinson.

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MINISTRY OF ENVIRONMENT
MEETING INFORMATION NOTE

September 19, 2013
File: 280-30
CLIFF/tracking #: 198192

PREPARED FOR: Honourable Mary Polak, Minister of Environment

DATE AND TIME OF MEETING: October 7th from 8:00 a.m. to 6:00 p.m.

ATTENDEES: Minister Polak

ISSUE(S): Minister Polak invited to attend the Canadian Innovation Summit: Powering Progress Together, on behalf of Shell Canada at the Vancouver Convention Centre.

BACKGROUND:

Shell is a global group of energy and petrochemical companies that has been active in Canada since 1911. In 2011, Shell has spent $1.1 billion on the research and development of technologies that will be needed to produce more energy, cleaner energy, and more efficient fuels and products.

Shell Canada has invited Minister Polak to attend the Canadian Innovation Summit: Powering Progress Together, on October 7, 2013. This is a first for Canada and only the second time this event will be held in North America. This event aims to bring together leading Canadian business and technology leaders with experts from various sectors, as well as global thought leaders, policy makers, and key stakeholders for collaborative discussion, dialogue, and debate.

The Innovation Summit will aim to address innovation in a number of contexts, including the future of energy, what it means to Canada and how it aligns with global perspectives on energy, as well as in relation to collaboration and energy literacy.

DISCUSSION:

British Columbia (BC) is recognized as a global leader in the fight against climate change and global warming. The opportunity to attend the Innovation Summit would be valuable for the Minister to promote BC's climate policy and political leadership with national and international thought leaders.

- It is in the interest of the province of BC to have a strong role or leadership role in setting the context and process for any discussion in Canada's energy solutions.

- The Province can communicate the success of BC's climate policies, advancing understanding of BC's green economy opportunities, and building momentum on potential Asia-Pacific linkages.

- BC has continued global leadership by implementing policies that support job growth, innovation, and environmental sustainability.
- By implementing policies that support sustainability in industry and innovation in the clean technology sector, the Province has created an environment where forward-thinking solutions can flourish.
- The Province is committed to having the cleanest LNG facilities in the world. Clean energy can play a role in supplying the LNG plant operations and electrifying the energy requirements for increased gas production and transmission, while also supporting the GHG emission targets.

Attachments: 1. Canadian Innovation Summit: Speaker Series Agenda

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Canadian Innovation Summit: Speaker Series Agenda

Date: Monday, October 7, 2013
Venue: Vancouver Convention Centre – West Building
Address: 1055 Canada Place, Vancouver
Time: 8:00 a.m. - 6:00 p.m.

Please note: the agenda below includes confirmed and invited speakers. The agenda will be updated as we finalize all speakers.

Time	Program
8:00 a.m.	*Registration, networking and refreshments*
8:30 a.m.	*Innovation Summit Welcome and Opening*
8:45 a.m.	*Powering Progress Together the Canadian Context* • Lorraine Mitchelmore, President and Country Chair, Shell Canada
9:00 a.m.	*Canadian Innovation: The Sky is Not the Limit* • Colonel Chris Hadfield, retired Canadian Space Agency Astronaut
10:00 a.m.	*Break and Innovation Showcase Networking*
10:30 a.m.	*The Global Energy Landscape and the Role of Innovation* • Matthias Bichsel, Director of Projects and Technology, Shell
10:45 a.m.	*The Future of Energy and the New Lens Scenarios (Mountains and Oceans)* • Jeremy Bentham, Vice President Global Business Environment, Shell
11:00 a.m.	**Speaker session** *Inspiring Innovation: What Does Innovation Mean to Us?* Participants include: • Jeremy Bentham, Vice President Global Business Environment, Shell • Dinara Millington, Senior Research Director, Canadian Energy Research Institute • John Wright, Senior Vice President, Ipsos, Global Public Affairs • Roberta Jamieson, President, Indspire • Yuen Pau Woo, President and CEO, Asia Pacific Foundation of Canada
12:00 p.m.	*Lunch and Innovation Showcase Networking*
1:00 p.m.	*Innovation and Sustainability* • Gerald Schotman, Chief Technology Officer and Executive Vice President Innovation/R&D, Shell

Time	Program
1:15 p.m.	**Speaker session** *How do We Turn Today's Innovations into Tomorrow's Collaborations: Case Studies to Brainstorming* Participants include: • Greg D'Avignon, President and CEO, BC Business Council • Dr. Dan Wicklum, Chief Executive, Canada's Oil Sands Innovation Alliance (COSIA) • Chief Roland Willson, West Moberly First Nation • A representative from the City of Dawson Creek, British Columbia • A representative from Pembina
2:15 p.m.	*Break and Innovation Showcase Networking*
2:45 p.m.	**Speaker session** *New Ways to Listen, Talk and Learn for a New Energy Dialogue* Participants include: • Gilles Gagnier, Director of New Media, Canadian Geographic • Andy Calitz, Vice President LNG, Shell Canada • Bob Oliver, Chief Executive Officer, Pollution Probe • A representative from Haisla Nation
3:45 p.m.	*Closing remarks* • TBD
4:00 p.m.	*Reception and Innovation Showcase Networking*
6:00 p.m.	*Speaker Series concludes*

MINISTRY OF ENVIRONMENT
INFORMATION NOTE

July 22, 2013
File: 280-30
CLIFF/tracking #: 197083

PREPARED FOR: The Honourable Mary Polak, Minister of Environment

ISSUE: Greenhouse gas (GHG) emissions from shale gas.

BACKGROUND:

On top of emissions from natural gas combustion and flaring, methane and carbon dioxide can also escape or be vented during natural gas extraction (including hydraulic fracturing, the stimulation of gas fields through high pressure injection of water, proppant and chemicals), processing and transmission. Methane emissions are a particular concern since they have a global warming impact 21 times higher than carbon dioxide. A small increase in the percentage of natural gas that escapes can have a significant impact on overall emissions.

In the 2013 Budget Estimates debate, MLAs Chandra Herbert and Holman questioned why estimates of the percentage of natural gas extracted that is lost as fugitive methane emissions differed significantly among BC, other North American jurisdictions, and scientific literature (0.3% and 3% and 7 to 8%, respectively). For the last several years a vigorous public and scientific debate has been ongoing about the level of shale gas GHG emissions.

The debate was escalated by a study by Professor Robert Howarth of Cornell University published in the journal *Climatic Change* in 2011 (attachment 2). In his work, Howarth calculated that between 3.6% and 7.9% of methane from shale gas production in the U.S. escapes to the atmosphere in venting and leaks over the lifetime of a well largely during the hydraulic fracturing and well completion processes.

Feedback on the Howarth study has been mixed. The Howarth work has been criticized as being based on very limited data set and not factoring in the impact of existing technology for reducing emissions. The leading consultancy IHS CERA indicated that extremely hazardous emissions would have been created at the well site if methane emissions were as high as Howarth assumes. Limited field work conducted in the U.S. by the National Oceanic and Atmospheric Administration (NOAA) found 4 to 9% of methane extracted became fugitive emissions, which is in line with Howarth's estimates and far higher than U.S. Environmental Protection Agency (EPA) estimates.

To address the uncertainty around fugitive and venting emissions during shale gas development, NOAA, the Environmental Defense Fund and industry partners are conducting a comprehensive assessment of U.S. natural gas emissions.

DISCUSSION:

A recent article referencing 'implausibly low' BC shale gas emissions was published in DeSmog Canada, a blog that looks at the environment, social issues, and the economy. Using this article as evidence, the BC Sustainable Energy Association and others are questioning if the natural gas to be used for LNG production is clean and if industry is operating with appropriate social license.

The DeSmog article uses U.S. emissions levels to estimate those from BC shale gas. However, natural gas extraction regulations and on-the-ground practices are significantly different in BC and the United States. Howarth's study uses worst-case scenario assumptions which are not applicable to British Columbia. For example, the vast majority of wells drilled in BC do not vent methane to the atmosphere as 'green completions'. In BC, methane is separated from water present and placed in a pipeline instead of being released to the atmosphere. Additionally, in BC leaks are more tightly regulated since some BC natural gas contains hydrogen sulfide, a toxic gas, which if leaked, would be a health emergency.

The best current BC estimates of natural gas methane emissions are determined using the *Greenhouse Gas Reduction (Cap and Trade) Act* Reporting Regulation. BC's Reporting Regulation uses prescribed Western Climate Initiative quantification methods (the same used for cap and trade in California and very similar to those used in regulatory reporting by the U.S. EPA). For methane fugitive emissions, the regulation largely uses emissions factors which assume a set percentage of methane will escape during extraction. Under the BC Reporting Regulation, companies have emissions reports verified by a third party; therefore, intentional underreporting is unlikely.

BC published detailed 2011 oil and gas emissions data for each specific source on its website. Methane emissions within the natural gas value chain are estimated to be 1.97 Mt carbon dioxide equivalent (CO_2e), or 0.3% of total natural gas production. Methane emissions make up ~20% of total oil and gas sector emissions (10.5 Mt CO_2e). (see attachment 1)

As part of efforts to continually improve reported data, the Climate Action Secretariat is currently working with the Canadian Association of Petroleum Producers and Ministry of Natural Gas Development to field test pneumatic device emission factors and pumps. Quantification method updates under development are also intended to reduce uncertainties for other sources. Though significant, this work does not address concerns about potential fracking-related emissions from geological formations, poor cement casing or produced water storage tanks. Knowledge of potential emissions from these sources is new and can only be addressed by field sampling.

NEXT STEPS:

s.13

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Attachments: 1. BC Reporting Regulation Oil and Gas Emissions Data
2. Howarth Study

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DMO	VJ	Sept 10/13
ADM	JM	Sept 9/13
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Attachment 1: BC Oil and Gas Emissions

Q: What percentage of methane produced in BC is vented deliberately and/or accidentally to the atmosphere?

Year	**Natural Gas Production** (m3)	**Methane Mass Density** (kg/m3)	**Methane Amount** (t CH4)	**CO2e Amount** (Mt CO2e) if all released into Atm.	**Actual Venting** (Mt CO2e)	**% Vented Out of Total Production**	**GWP 100yr**
2010	34,991,762,000	0.678	23,724,415	498.21	1.97	0.4%	21
2011	41,441,414,000	0.678	28,097,279	590.04	1.97	0.3%	21

Q: What are the emissions from the different segments of the natural gas value chain?

Row Labels	**Venting**	**Fugitive**	**Flaring**	**Stationary Combustion**	**Sum of Total Wastewater**	**Total**
Oil and Gas Extraction	3,282,489	962,670	528,510	5,373,869	17	10,147,555
Natural Gas Distribution	6,462	16,537	2,617	6,318	0	31,934
Pipeline Transportation	42,816	71,897	2	214,036	0	32,8752
Grand Total	**3, 331,767**	**1,051,104**	**531,129**	**5,594,223**	**17**	**10,508,241**

Q: What are the emissions from the specific natural value chain sources?

Emission Source	Category	Total	Percent
Stationary Combustion: Natural Gas	Stationary Combustion	5,060,500	49.0
Stationary Combustion: Other Fuels	Stationary Combustion	276,100	2.7
Electricity Generation	Electricity Generation	150,600	1.5
Well Testing Flares	Flaring	139,500	1.4
Associated Gas Flares	Flaring	35,200	0.3
Flare Stacks	Flaring	362,700	3.5
Continuous High Bleed Device Vents	Venting	311,100	3.0
Pneumatic Pump Vents	Venting	173,700	1.7
Continuous Low Bleed and Intermittent Device Vents	Venting	68,900	0.7
Acid Gas Removal	Venting	2,408,000	23.3
Dehydrator Vents	Venting	97,100	0.9
Well Venting for Liquids Unloading	Venting	6,200	0.1
Well Venting, with or Without Hydraulic Fracturing	Venting	4,100	0.0
Blowdown Vent Stacks	Venting	58,900	0.6
Well Testing Venting	Venting	1,100	0.0
Associated Gas Venting	Venting	730	0.0
Centrifugal Compressor Vents	Venting	102,000	1.0
Reciprocating Compressor Vents	Venting	52,400	0.5
EOR Injection Pump Blowdowns	Venting	-	-
Other Venting Sources	Venting	40,900	0.4
Storage Tanks	Fugitive	16,900	0.2
Gathering Pipeline Equipment Leaks	Fugitive	156,500	1.5
Equipment Leaks from Valves, Connectors, etc.	Fugitive	784,300	7.6
Above-Ground Meters/Regulators at Gate Stations	Fugitive	5,900	0.1
Below-Ground Meters/Regulators/Valves	Fugitive	8,500	0.1
Other Fugitive Sources	Fugitive	9,400	0.1
Wastewater processing	Wastewater	17	0.0
Total		10,331,500	100

Climatic Change
DOI 10.1007/s10584-011-0061-5

LETTER

Methane and the greenhouse-gas footprint of natural gas from shale formations

A letter

Robert W. Howarth · Renee Santoro · Anthony Ingraffea

Received: 12 November 2010 / Accepted: 13 March 2011

Abstract We evaluate the greenhouse gas footprint of natural gas obtained by high-volume hydraulic fracturing from shale formations, focusing on methane emissions. Natural gas is composed largely of methane, and 3.6% to 7.9% of the methane from shale-gas production escapes to the atmosphere in venting and leaks over the life-time of a well. These methane emissions are at least 30% more than and perhaps more than twice as great as those from conventional gas. The higher emissions from shale gas occur at the time wells are hydraulically fractured—as methane escapes from flow-back return fluids—and during drill out following the fracturing. Methane is a powerful greenhouse gas, with a global warming potential that is far greater than that of carbon dioxide, particularly over the time horizon of the first few decades following emission. Methane contributes substantially to the greenhouse gas footprint of shale gas on shorter time scales, dominating it on a 20-year time horizon. The footprint for shale gas is greater than that for conventional gas or oil when viewed on any time horizon, but particularly so over 20 years. Compared to coal, the footprint of shale gas is at least 20% greater and perhaps more than twice as great on the 20-year horizon and is comparable when compared over 100 years.

Keywords Methane · Greenhouse gases · Global warming · Natural gas · Shale gas · Unconventional gas · Fugitive emissions · Lifecycle analysis · LCA · Bridge fuel · Transitional fuel · Global warming potential · GWP

Electronic supplementary material The online version of this article (doi:10.1007/s10584-011-0061-5) contains supplementary material, which is available to authorized users.

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Many view natural gas as a transitional fuel, allowing continued dependence on fossil fuels yet reducing greenhouse gas (GHG) emissions compared to oil or coal over coming decades (Pacala and Socolow 2004). Development of "unconventional" gas dispersed in shale is part of this vision, as the potential resource may be large, and in many regions conventional reserves are becoming depleted (Wood et al. 2011). Domestic production in the U.S. was predominantly from conventional reservoirs through the 1990s, but by 2009 U.S. unconventional production exceeded that of conventional gas. The Department of Energy predicts that by 2035 total domestic production will grow by 20%, with unconventional gas providing 75% of the total (EIA 2010a). The greatest growth is predicted for shale gas, increasing from 16% of total production in 2009 to an expected 45% in 2035.

Although natural gas is promoted as a bridge fuel over the coming few decades, in part because of its presumed benefit for global warming compared to other fossil fuels, very little is known about the GHG footprint of unconventional gas. Here, we define the GHG footprint as the total GHG emissions from developing and using the gas, expressed as equivalents of carbon dioxide, per unit of energy obtained during combustion. The GHG footprint of shale gas has received little study or scrutiny, although many have voiced concern. The National Research Council (2009) noted emissions from shale-gas extraction may be greater than from conventional gas. The Council of Scientific Society Presidents (2010) wrote to President Obama, warning that some potential energy bridges such as shale gas have received insufficient analysis and may aggravate rather than mitigate global warming. And in late 2010, the U.S. Environmental Protection Agency issued a report concluding that fugitive emissions of methane from unconventional gas may be far greater than for conventional gas (EPA 2010).

Fugitive emissions of methane are of particular concern. Methane is the major component of natural gas and a powerful greenhouse gas. As such, small leakages are important. Recent modeling indicates methane has an even greater global warming potential than previously believed, when the indirect effects of methane on atmospheric aerosols are considered (Shindell et al. 2009). The global methane budget is poorly constrained, with multiple sources and sinks all having large uncertainties. The radiocarbon content of atmospheric methane suggests fossil fuels may be a far larger source of atmospheric methane than generally thought (Lassey et al. 2007).

The GHG footprint of shale gas consists of the direct emissions of CO_2 from end-use consumption, indirect emissions of CO_2 from fossil fuels used to extract, develop, and transport the gas, and methane fugitive emissions and venting. Despite the high level of industrial activity involved in developing shale gas, the indirect emissions of CO_2 are relatively small compared to those from the direct combustion of the fuel: 1 to 1.5 g C MJ^{-1} (Santoro et al. 2011) vs 15 g C MJ^{-1} for direct emissions (Hayhoe et al. 2002). Indirect emissions from shale gas are estimated to be only 0.04 to 0.45 g C MJ^{-1} greater than those for conventional gas (Wood et al. 2011). Thus, for both conventional and shale gas, the GHG footprint is dominated by the direct CO_2 emissions and fugitive methane emissions. Here we present estimates for methane emissions as contributors to the GHG footprint of shale gas compared to conventional gas.

Our analysis uses the most recently available data, relying particularly on a technical background document on GHG emissions from the oil and gas industry (EPA 2010) and materials discussed in that report, and a report on natural gas losses on federal lands from the General Accountability Office (GAO 2010). The

EPA (2010) report is the first update on emission factors by the agency since 1996 (Harrison et al. 1996). The earlier report served as the basis for the national GHG inventory for the past decade. However, that study was not based on random sampling or a comprehensive assessment of actual industry practices, but rather only analyzed facilities of companies that voluntarily participated (Kirchgessner et al. 1997). The new EPA (2010) report notes that the 1996 "study was conducted at a time when methane emissions were not a significant concern in the discussion about GHG emissions" and that emission factors from the 1996 report "are outdated and potentially understated for some emissions sources." Indeed, emission factors presented in EPA (2010) are much higher, by orders of magnitude for some sources.

1 Fugitive methane emissions during well completion

Shale gas is extracted by high-volume hydraulic fracturing. Large volumes of water are forced under pressure into the shale to fracture and re-fracture the rock to boost gas flow. A significant amount of this water returns to the surface as flow-back within the first few days to weeks after injection and is accompanied by large quantities of methane (EPA 2010). The amount of methane is far more than could be dissolved in the flow-back fluids, reflecting a mixture of fracture-return fluids and methane gas. We have compiled data from 2 shale gas formations and 3 tight-sand gas formations in the U.S. Between 0.6% and 3.2% of the life-time production of gas from wells is emitted as methane during the flow-back period (Table 1). We include tight-sand formations since flow-back emissions and the patterns of gas production over time are similar to those for shale (EPA 2010). Note that the rate of methane emitted during flow-back (column B in Table 1) correlates well to the initial production rate for the well following completion (column C in Table 1). Although the data are limited, the variation across the basins seems reasonable: the highest methane emissions during flow-back were in the Haynesville, where initial pressures and initial production were very high, and the lowest emissions were in the Uinta, where the flow-back period was the shortest and initial production following well completion was low. However, we note that the data used in Table 1 are not well documented, with many values based on PowerPoint slides from EPA-sponsored workshops. For this paper, we therefore choose to represent gas losses from flow-back fluids as the mean value from Table 1: 1.6%.

More methane is emitted during "drill-out," the stage in developing unconventional gas in which the plugs set to separate fracturing stages are drilled out to release gas for production. EPA (2007) estimates drill-out emissions at 142×10^3 to 425×10^3 m^3 per well. Using the mean drill-out emissions estimate of 280×10^3 m^3 (EPA 2007) and the mean life-time gas production for the 5 formations in Table 1 (85×10^6 m^3), we estimate that 0.33% of the total life-time production of wells is emitted as methane during the drill-out stage. If we instead use the average life-time production for a larger set of data on 12 formations (Wood et al. 2011), 45×10^6 m^3, we estimate a percentage emission of 0.62%. More effort is needed to determine drill-out emissions on individual formation. Meanwhile, in this paper we use the conservative estimate of 0.33% for drill-out emissions.

Combining losses associated with flow-back fluids (1.6%) and drill out (0.33%), we estimate that 1.9% of the total production of gas from an unconventional shale-gas

Table 1 Methane emissions during the flow-back period following hydraulic fracturing, initial gas production rates following well completion, life-time gas production of wells, and the methane emitted during flow-back expressed as a percentage of the life-time production for five unconventional wells in the United States

	(A) Methane emitted during flow-back (10^3 m^3)[a]	(B) Methane emitted per day during flow-back (10^3 m^3 day^{-1})[b]	(C) Initial gas production at well completion (10^3 m^3 day^{-1})[c]	(D) Life-time production of well (10^6 m^3)[d]	(E) Methane emitted during flow-back as % of life-time production[e]
Haynesville (Louisiana, shale)	6,800	680	640	210	3.2
Barnett (Texas, shale)	370	41	37	35	1.1
Piceance (Colorado, tight sand)	710	79	57	55	1.3
Uinta (Utah, tight sand)	255	51	42	40	0.6
Den-Jules (Colorado, tight sand)	140	12	11	?	?

Flow-back is the return of hydraulic fracturing fluids to the surface immediately after fracturing and before well completion. For these wells, the flow-back period ranged from 5 to 12 days

[a]Haynesville: average from Eckhardt et al. (2009); Piceance: EPA (2007); Barnett: EPA (2004); Uinta: Samuels (2010); Denver-Julesburg: Bracken (2008)

[b]Calculated by dividing the total methane emitted during flow-back (column A) by the duration of flow-back. Flow-back durations were 9 days for Barnett (EPA 2004), 8 days for Piceance (EPA 2007), 5 days for Uinta (Samuels 2010), and 12 days for Denver-Julesburg (Bracken 2008); median value of 10 days for flow-back was assumed for Haynesville

[c]Haynesville: http://shale.typepad.com/haynesvilleshale/2009/07/chesapeake-energy-haynesville-shale-decline-curve.html1/7/2011 and http://oilshalegas.com/haynesvilleshalestocks.html; Barnett: http://oilshalegas.com/barnettshale.html; Piceance: Kruuskraa (2004) and Henke (2010); Uinta: http://www.epmag.com/archives/newsComments/6242.htm; Denver-Julesburg: http://www.businesswire.com/news/home/20100924005169/en/Synergy-Resources-Corporation-Reports-Initial-Production-Rates

[d]Based on averages for these basins. Haynesville: http://shale.typepad.com/haynesvilleshale/decline-curve/); Barnett: http://www.aapg.org/explorer/2002/07jul/barnett_shale.cfm and Wood et al. (2011); Piceance: Kruuskraa (2004); Uinta: http://www.epmag.com/archives/newsComments/6242.htm

[e]Calculated by dividing column (A) by column (D)

Table 2 Fugitive methane emissions associated with development of natural gas from conventional wells and from shale formations (expressed as the percentage of methane produced over the lifecycle of a well)

	Conventional gas	Shale gas
Emissions during well completion	0.01%	1.9%
Routine venting and equipment leaks at well site	0.3 to 1.9%	0.3 to 1.9%
Emissions during liquid unloading	0 to 0.26%	0 to 0.26%
Emissions during gas processing	0 to 0.19%	0 to 0.19%
Emissions during transport, storage, and distribution	1.4 to 3.6%	1.4 to 3.6%
Total emissions	1.7 to 6.0%	3.6 to 7.9%

See text for derivation of estimates and supporting information

well is emitted as methane during well completion (Table 2). Again, this estimate is uncertain but conservative.

Emissions are far lower for conventional natural gas wells during completion, since conventional wells have no flow-back and no drill out. An average of 1.04×10^3 m^3 of methane is released per well completed for conventional gas (EPA 2010), corresponding to 1.32×10^3 m^3 natural gas (assuming 78.8% methane content of the gas). In 2007, 19,819 conventional wells were completed in the US (EPA 2010), so we estimate a total national emission of 26×10^6 m^3 natural gas. The total national production of onshore conventional gas in 2007 was 384×10^9 m^3 (EIA 2010b). Therefore, we estimate the average fugitive emissions at well completion for conventional gas as 0.01% of the life-time production of a well (Table 2), three orders of magnitude less than for shale gas.

2 Routine venting and equipment leaks

After completion, some fugitive emissions continue at the well site over its lifetime. A typical well has 55 to 150 connections to equipment such as heaters, meters, dehydrators, compressors, and vapor-recovery apparatus. Many of these potentially leak, and many pressure relief valves are designed to purposefully vent gas. Emissions from pneumatic pumps and dehydrators are a major part of the leakage (GAO 2010). Once a well is completed and connected to a pipeline, the same technologies are used for both conventional and shale gas; we assume that these post-completion fugitive emissions are the same for shale and conventional gas. GAO (2010) concluded that 0.3% to 1.9% of the life-time production of a well is lost due to routine venting and equipment leaks (Table 2). Previous studies have estimated routine well-site fugitive emissions as approximately 0.5% or less (Hayhoe et al. 2002; Armendariz 2009) and 0.95% (Shires et al. 2009). Note that none of these estimates include accidents or emergency vents. Data on emissions during emergencies are not available and have never, as far as we can determine, been used in any estimate of emissions from natural gas production. Thus, our estimate of 0.3% to 1.9% leakage is conservative. As we discuss below, the 0.3% reflects use of best available technology.

Additional venting occurs during "liquid unloading." Conventional wells frequently require multiple liquid-unloading events as they mature to mitigate water intrusion as reservoir pressure drops. Though not as common, some unconventional wells may also require unloading. Empirical data from 4 gas basins indicate that 0.02

to 0.26% of total life-time production of a well is vented as methane during liquid unloading (GAO 2010). Since not all wells require unloading, we set the range at 0 to 0.26% (Table 2).

3 Processing losses

Some natural gas, whether conventional or from shale, is of sufficient quality to be "pipeline ready" without further processing. Other gas contains sufficient amounts of heavy hydrocarbons and impurities such as sulfur gases to require removal through processing before the gas is piped. Note that the quality of gas can vary even within a formation. For example, gas from the Marcellus shale in northeastern Pennsylvania needs little or no processing, while gas from southwestern Pennsylvania must be processed (NYDEC 2009). Some methane is emitted during this processing. The default EPA facility-level fugitive emission factor for gas processing indicates a loss of 0.19% of production (Shires et al. 2009). We therefore give a range of 0% (i.e. no processing, for wells that produce "pipeline ready" gas) to 0.19% of gas produced as our estimate of processing losses (Table 2). Actual measurements of processing plant emissions in Canada showed fourfold greater leakage than standard emission factors of the sort used by Shires et al. (2009) would indicate (Chambers 2004), so again, our estimates are very conservative.

4 Transport, storage, and distribution losses

Further fugitive emissions occur during transport, storage, and distribution of natural gas. Direct measurements of leakage from transmission are limited, but two studies give similar leakage rates in both the U.S. (as part of the 1996 EPA emission factor study; mean value of 0.53%; Harrison et al. 1996; Kirchgessner et al. 1997) and in Russia (0.7% mean estimate, with a range of 0.4% to 1.6%; Lelieveld et al. 2005). Direct estimates of distribution losses are even more limited, but the 1996 EPA study estimates losses at 0.35% of production (Harrison et al. 1996; Kirchgessner et al. 1997). Lelieveld et al. (2005) used the 1996 emission factors for natural gas storage and distribution together with their transmission estimates to suggest an overall average loss rate of 1.4% (range of 1.0% to 2.5%). We use this 1.4% leakage as the likely lower limit (Table 2). As noted above, the EPA 1996 emission estimates are based on limited data, and Revkin and Krauss (2009) reported "government scientists and industry officials caution that the real figure is almost certainly higher." Furthermore, the IPCC (2007) cautions that these "bottom-up" approaches for methane inventories often underestimate fluxes.

Another way to estimate pipeline leakage is to examine "lost and unaccounted for gas," e.g. the difference between the measured volume of gas at the wellhead and that actually purchased and used by consumers. At the global scale, this method has estimated pipeline leakage at 2.5% to 10% (Crutzen 1987; Cicerone and Oremland 1988; Hayhoe et al. 2002), although the higher value reflects poorly maintained pipelines in Russia during the Soviet collapse, and leakages in Russia are now far less (Lelieveld et al. 2005; Reshetnikov et al. 2000). Kirchgessner et al. (1997) argue against this approach, stating it is "subject to numerous errors including gas theft, variations in temperature and pressure, billing cycle differences, and meter inaccuracies." With the exception of theft, however, errors should be randomly distributed and should not bias the leakage estimate high or low. Few recent data on lost and unaccounted gas are publicly available, but statewide data for Texas averaged 2.3% in 2000 and 4.9% in 2007 (Percival 2010). In 2007, the State of Texas passed new legislation to regulate lost and unaccounted for gas; the legislation originally proposed a 5% hard cap which was dropped in the face of industry opposition (Liu 2008; Percival 2010). We take the mean of the 2000 and 2007 Texas data for missing and unaccounted gas (3.6%) as the upper limit of downstream losses (Table 2), assuming that the higher value for 2007 and lower value for 2000 may potentially reflect random variation in billing cycle differences. We believe this is a conservative upper limit, particularly given the industry resistance to a 5% hard cap.

Our conservative estimate of 1.4% to 3.6% leakage of gas during transmission, storage, and distribution is remarkably similar to the 2.5% "best estimate" used by Hayhoe et al. (2002). They considered the possible range as 0.2% and 10%.

5 Contribution of methane emissions to the GHG footprints of shale gas and conventional gas

Summing all estimated losses, we calculate that during the life cycle of an average shale-gas well, 3.6 to 7.9% of the total production of the well is emitted to the atmosphere as methane (Table 2). This is at least 30% more and perhaps more than twice as great as the life-cycle methane emissions we estimate for conventional gas, 1.7% to 6%. Methane is a far more potent GHG than is CO_2, but methane also has a tenfold shorter residence time in the atmosphere, so its effect on global warming attenuates more rapidly (IPCC 2007). Consequently, to compare the global warming potential of methane and CO_2 requires a specific time horizon. We follow Lelieveld et al. (2005) and present analyses for both 20-year and 100-year time horizons. Though the 100-year horizon is commonly used, we agree with Nisbet et al. (2000) that the 20-year horizon is critical, given the need to reduce global warming in coming decades (IPCC 2007). We use recently modeled values for the global warming potential of methane compared to CO_2: 105 and 33 on a mass-to-mass basis for 20 and 100 years, respectively, with an uncertainty of plus or minus 23% (Shindell et al. 2009). These are somewhat higher than those presented in the 4th assessment report of the IPCC (2007), but better account for the interaction of methane with aerosols. Note that carbon-trading markets use a lower global-warming potential yet of only 21 on the 100-year horizon, but this is based on the 2nd IPCC (1995) assessment, which is clearly out of date on this topic. See Electronic Supplemental Materials for the methodology for calculating the effect of methane on GHG in terms of CO_2 equivalents.

Methane dominates the GHG footprint for shale gas on the 20-year time horizon, contributing 1.4- to 3-times more than does direct CO_2 emission (Fig. 1a). At this time scale, the GHG footprint for shale gas is 22% to 43% greater than that for conventional gas. When viewed at a time 100 years after the emissions, methane emissions still contribute significantly to the GHG footprints, but the effect is diminished by the relatively short residence time of methane in the atmosphere. On this time frame, the GHG footprint for shale gas is 14% to 19% greater than that for conventional gas (Fig. 1b).

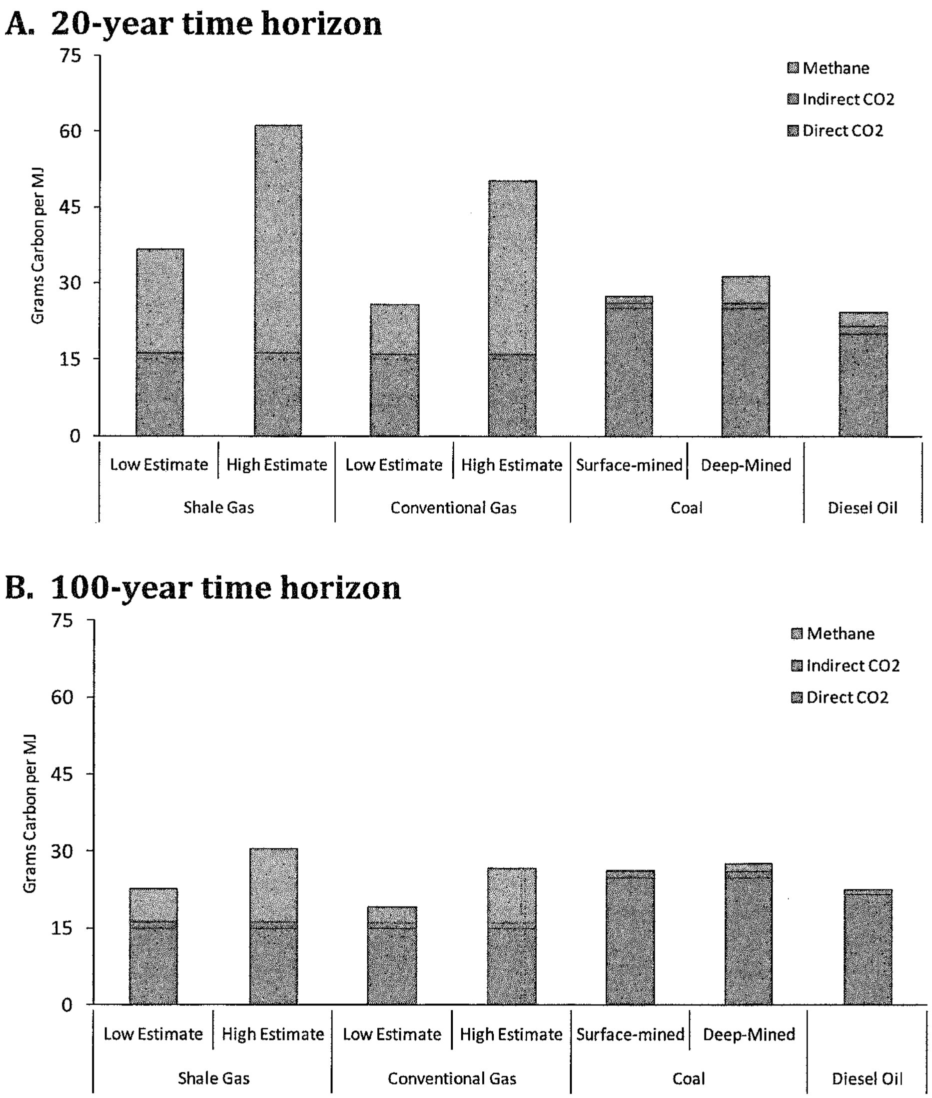

Fig. 1 Comparison of greenhouse gas emissions from shale gas with low and high estimates of fugitive methane emissions, conventional natural gas with low and high estimates of fugitive methane emissions, surface-mined coal, deep-mined coal, and diesel oil. **a** is for a 20-year time horizon, and **b** is for a 100-year time horizon. Estimates include direct emissions of CO_2 during combustion (*blue bars*), indirect emissions of CO_2 necessary to develop and use the energy source (*red bars*), and fugitive emissions of methane, converted to equivalent value of CO_2 as described in the text (*pink bars*). Emissions are normalized to the quantity of energy released at the time of combustion. The conversion of methane to CO_2 equivalents is based on global warming potentials from Shindell et al. (2009) that include both direct and indirect influences of methane on aerosols. Mean values from Shindell et al. (2009) are used here. Shindell et al. (2009) present an uncertainty in these mean values of plus or minus 23%, which is not included in this figure

6 Shale gas versus other fossil fuels

Considering the 20-year horizon, the GHG footprint for shale gas is at least 20% greater than and perhaps more than twice as great as that for coal when expressed per quantity of energy available during combustion (Fig. 1a; see Electronic Supplemental Materials for derivation of the estimates for diesel oil and coal). Over the 100-year frame, the GHG footprint is comparable to that for coal: the low-end shale-gas emissions are 18% lower than deep-mined coal, and the high-end shale-gas emissions are 15% greater than surface-mined coal emissions (Fig. 1b). For the 20 year horizon, the GHG footprint of shale gas is at least 50% greater than for oil, and perhaps 2.5-times greater. At the 100-year time scale, the footprint for shale gas is similar to or 35% greater than for oil.

We know of no other estimates for the GHG footprint of shale gas in the peer-reviewed literature. However, we can compare our estimates for conventional gas with three previous peer-reviewed studies on the GHG emissions of conventional natural gas and coal: Hayhoe et al. (2002), Lelieveld et al. (2005), and Jamarillo et al. (2007). All concluded that GHG emissions for conventional gas are less than for coal, when considering the contribution of methane over 100 years. In contrast, our analysis indicates that conventional gas has little or no advantage over coal even over the 100-year time period (Fig. 1b). Our estimates for conventional-gas methane emissions are in the range of those in Hayhoe et al. (2002) but are higher than those in Lelieveld et al. (2005) and Jamarillo et al. (2007) who used 1996 EPA emission factors now known to be too low (EPA 2010). To evaluate the effect of methane, all three of these studies also used global warming potentials now believed to be too low (Shindell et al. 2009). Still, Hayhoe et al. (2002) concluded that under many of the scenarios evaluated, a switch from coal to conventional natural gas could aggravate global warming on time scales of up to several decades. Even with the lower global warming potential value, Lelieveld et al. (2005) concluded that natural gas has a greater GHG footprint than oil if methane emissions exceeded 3.1% and worse than coal if the emissions exceeded 5.6% on the 20-year time scale. They used a methane global warming potential value for methane from IPCC (1995) that is only 57% of the new value from Shindell et al. (2009), suggesting that in fact methane emissions of only 2% to 3% make the GHG footprint of conventional gas worse than oil and coal. Our estimates for fugitive shale-gas emissions are 3.6 to 7.9%.

Our analysis does not consider the efficiency of final use. If fuels are used to generate electricity, natural gas gains some advantage over coal because of greater efficiencies of generation (see Electronic Supplemental Materials). However, this does not greatly affect our overall conclusion: the GHG footprint of shale gas approaches or exceeds coal even when used to generate electricity (Table in Electronic Supplemental Materials). Further, shale-gas is promoted for other uses, including as a heating and transportation fuel, where there is little evidence that efficiencies are superior to diesel oil.

7 Can methane emissions be reduced?

The EPA estimates that 'green' technologies can reduce gas-industry methane emissions by 40% (GAO 2010). For instance, liquid-unloading emissions can be greatly reduced with plunger lifts (EPA 2006; GAO 2010); industry reports a 99% venting reduction in the San Juan basin with the use of smart-automated plunger lifts (GAO 2010). Use of flash-tank separators or vapor recovery units can reduce dehydrator emissions by 90% (Fernandez et al. 2005). Note, however, that our lower range of estimates for 3 out of the 5 sources as shown in Table 2 already reflect the use of best technology: 0.3% lower-end estimate for routine venting and leaks at well sites (GAO 2010), 0% lower-end estimate for emissions during liquid unloading, and 0% during processing.

Methane emissions during the flow-back period in theory can be reduced by up to 90% through Reduced Emission Completions technologies, or REC (EPA 2010). However, REC technologies require that pipelines to the well are in place prior to completion, which is not always possible in emerging development areas. In any event, these technologies are currently not in wide use (EPA 2010).

If emissions during transmission, storage, and distribution are at the high end of our estimate (3.6%; Table 2), these could probably be reduced through use of better storage tanks and compressors and through improved monitoring for leaks. Industry has shown little interest in making the investments needed to reduce these emission sources, however (Percival 2010).

Better regulation can help push industry towards reduced emissions. In reconciling a wide range of emissions, the GAO (2010) noted that lower emissions in the Piceance basin in Colorado relative to the Uinta basin in Utah are largely due to a higher use of low-bleed pneumatics in the former due to stricter state regulations.

8 Conclusions and implications

The GHG footprint of shale gas is significantly larger than that from conventional gas, due to methane emissions with flow-back fluids and from drill out of wells during well completion. Routine production and downstream methane emissions are also large, but are the same for conventional and shale gas. Our estimates for these routine and downstream methane emission sources are within the range of those reported by most other peer-reviewed publications inventories (Hayhoe et al. 2002; Lelieveld et al. 2005). Despite this broad agreement, the uncertainty in the magnitude of fugitive emissions is large. Given the importance of methane in global warming, these emissions deserve far greater study than has occurred in the past. We urge both more direct measurements and refined accounting to better quantify lost and unaccounted for gas.

The large GHG footprint of shale gas undercuts the logic of its use as a bridging fuel over coming decades, if the goal is to reduce global warming. We do not intend that our study be used to justify the continued use of either oil or coal, but rather to demonstrate that substituting shale gas for these other fossil fuels may not have the desired effect of mitigating climate warming.

Finally, we note that carbon-trading markets at present under-value the greenhouse warming consequences of methane, by focusing on a 100-year time horizon and by using out-of-date global warming potentials for methane. This should be corrected, and the full GHG footprint of unconventional gas should be used in planning for alternative energy futures that adequately consider global climate change.

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MINISTRY OF ENVIRONMENT
MEETING INFORMATION NOTE

October 1, 2013
File: 280-20
CLIFF/tracking #:198720

PREPARED FOR: Honourable Mary Polak, Minister of Environment

DATE AND TIME OF MEETING: October 8th, 3:30-4:15 pm

ATTENDEES: Minister Mary Polak, Minister Rich Coleman, Coastal First Nations staff, Tim Lesiuk from Climate Action Secretariat

ISSUES: 1) Offset investments as an liquefied natural gas (LNG); Greenhouse gas (GHG) mitigation strategy 2) Renewable energy procurement 3) LNG benefit sharing

BACKGROUND:

The Coastal First Nations (CFN) is an alliance of First Nations on British Columbia's North and Central Coast and Haida Gwaii. The Coastal First Nations include Wuikinuxv Nation, Heiltsuk, Kitasoo/Xaixais, Nuxalk Nation, Gitga'at, Metlakatla, Old Massett, Skidegate, and Council of the Haida Nation. Several CFN nations are located near the proposed sites of BC LNG facilities.

The CFN and the Province have agreed to a Framework Agreement on Regional Liquefied Natural Gas Development which covers key regional issues related to LNG, including air pollution, greenhouse gas emissions, increased marine vessel shipping carbon offsets, regional renewable energy and regional economic benefits.

The CFN has requested a meeting to discuss offset purchases as a part of an LNG--GHG emission mitigation strategy, renewable energy procurement, and benefit sharing for CFN nations.

DISCUSSION:

Offset Purchases:

s.13, s.16, s.17

s.13, s.16

SUGGESTED RESPONSE:

s.13

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ADM – CAS	JM	Oct 4/13
ED – CAS	TL	Oct 3/13
Author - CAS	HP	Oct 2/13

MINISTRY OF ENVIRONMENT
INFORMATION NOTE

November 15, 2013
File: 280-20
CLIFF/tracking #:199160

PREPARED FOR: Honourable Mary Polak, Minister of Environment

DATE AND TIME OF MEETING: Friday, November 22, 2013 at 2:00 p.m. by Telepresence
ATTENDEES: from Climate Action Secretariat: James Mack, Head; Liz Lilly, Executive Director; Dennis Paradine, Manager

ISSUE: Impacts of Greenhouse Gas Accounting and Measurement Changes *(Meeting Title: Federal Changes to Global Warming Potential Emission Factors)*

BACKGROUND:

International greenhouse gas (GHG) accounting and measurement practices are changing as research and the understanding of science evolves. Three recent developments have implications for BC's greenhouse gas baseline and progress reporting:

1. The federal government has updated its global-warming-potential factors (GWPs), based on the values listed in the Intergovernmental Panel on Climate Change's Fourth Assessment Report, published in 2007. The main impact is that the GWP for methane has increased by nearly 20 per cent, from 21 to 25. The GWP for nitrous oxide decreases from 310 to 298. The new GWPs will be applied to 2013 GHG data to be reported by industry to the federal government in 2014. BC has been using the same GWPs as the federal government, and will need to follow suit in order to maintain consistency of data between Federal and Provincial accounts.

2. The United Nations Framework Convention on Climate Change (UNFCCC) forest carbon accounting framework has been updated and will be applied to forest management reporting to UNFCCC starting with the 2013 inventory year (reported in 2015). Application of this changed framework will significantly alter how BC can meet its legislated emission reduction targets.

3. Based upon journal papers and other documents from the United States, there is concern from some parties that 'fugitive leaks' from oil and gas facilities are higher than currently reported in BC. The Ministries of Environment (MOE) and Natural Gas Development (MNGD) have been working in partnership with the Canadian Association of Petroleum Producers (CAPP) to update to emission factors for one potential source of fugitive leaks, pneumatic devices or pumps (equipment used in the oil and gas sector to regulate gas flows).

DISCUSSION:

s.13, s.12, s.17

NEXT STEPS:

s.13, s.12

Attachment: Agenda for BC Oil and Gas Technical Greenhouse Gas Data Workshop

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Reviewed by	Initials	Date
DM	WS	20/11/13
DMO	-	-
ADM	JM	18/11/2013
Dir./Mgr.	LL	15/11/2013
Author	DP/KZ	15/11/2013

DRAFT AGENDA

DAY 1: THURSDAY, NOVEMBER 28, 2013 12:30 PM to 5:00 PM

11:30 AM – 12:30 PM	**Lunch (provided)**

12:30 PM – 12:45 PM	**Welcome, purpose of the workshop**

12:45 PM - 1:45 PM	**Keynote Address: Measurements of Methane Emissions at Natural Gas Production Sites in the US**

- Dr. David Allen, Department of Chemical Engineering, University of Texas at Austin

1: 45 PM - 2:30 PM	**BC's *Reporting Regulation, quantification methods and reported* oil and gas GHG emissions**

- Dennis Paradine, Manager, Climate Change Policy, Climate Action Secretariat, BC Ministry of Environment and Richard Caesar, Project Manager, Policy and Royalty Branch, BC Ministry of Natural Gas Development

2:30 PM - 3:00 PM	**Break and networking**

3:00 PM - 5:00 PM	**GHG emissions sources *(panel hosted by Dr. Allen)***

- Sources of greenhouse gas emissions in BC's oil and gas sector and how they are regulated (Kevin Parsonage, Supervisor, Field Engineering & Technical Investigations, BC Oil and Gas Commission) (25 min)
- Methodologies for the detection of methane and non-methane hydrocarbon emissions downwind from oil and gas operations (Ann-Lise Norman, Associate Professor, Department of Physics and Astronomy, University of Calgary (25 min)
- Greenhouse gas emissions from BC's gas sector: A scan of ENGO perspectives (Matt Horne, Associate Regional Director, British Columbia, Pembina Institute) (20 min)
- Some Dene Tha' perspectives relating to oil and gas activities in northeast BC (Matthew Munson, B.Sc., Director of Lands and Environment, Dene Tha' First Nation) (20 min)
- Questions/discussion (20 min)
- Summary of first day discussions; outline of day 2 agenda (10 min)

5:00 PM – 6:30 PM	**Social (in the Segal Building; refreshments and appetizers provided)**

MINISTRY OF ENVIRONMENT
MEETING INFORMATION NOTE

November 15, 2013
File: 280-20
CLIFF/tracking #: 199481

PREPARED FOR: Honourable Mary Polak, Minister of Environment

DATE AND TIME OF MEETING: November 25, 2013 at 10:15am

ATTENDEES: Ian Thompson, President, Western Canadian Biodiesel Association; Conferencing in: James Mack, Head, Climate Action Secretariat

ISSUE: The Western Canadian Biodiesel Association (WCBA) has requested to meet with the Minister to discuss the Renewable and Low Carbon Fuel Requirements Regulations and provide recommendations for strengthening the regulation.

BACKGROUND:

<u>Western Canadian Biodiesel Association</u>
In December, 2012, the Alberta Biodiesel Association, the BC Biodiesel Association, and biodiesel stakeholders in Saskatchewan and Manitoba incorporated the Western Canada Biodiesel Association. The WCBA is a non-profit organization established to promote the use of biodiesel through education, outreach, and advocacy, to collaborate with other stakeholders to advance the production of sustainable biofuels in Canada, and to support biodiesel manufacturing in compliance with Canadian General Standards Board and the American Society for Testing and Materials industry standards.

Ian Thompson has been the President of the WCBA since December, 2012, and is a Partner with the Waterfall Advisors Group (specializing in the Canadian bio-energy industry).

<u>Renewable and Low Carbon Fuels Requirements Regulation</u>
The Renewable and Low Carbon Fuel Requirements Regulation (RLCFRR) falls under the responsibility of the Ministry of Energy and Mines. The RLCFRR serves to reduce British Columbia's reliance on non-renewable fuels, helps reduce the environmental impact of transportation fuels, and contributes to a new, low-carbon economy. It enables the province to set benchmarks for the amount of renewable fuel in BC's transportation fuel blends, reduce the carbon intensity of transportation fuels, and meet its commitment to adopt a low-carbon fuel standard.

The RLCFRR reduces the carbon intensity of transportation fuels through two major requirements; (1) a *Renewable Fuel Requirement (*5% renewable content in gasoline and 4% renewable content in diesel; and (2) a *Low Carbon Fuel Requirement (*10% reduction in carbon intensity of transportation fuels, on a life cycle assessment, by 2020).

The use of renewable fuel in 2010 saved 419,000 tonnes of greenhouse gas emissions from being released into the environment, the equivalent of about 82,000 cars being removed from the road.

DISCUSSION:

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SUGGESTED RESPONSE:

s.13

Attachment: Information Bulletin RLCF-011 "Approved Version of GHGenius"

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DM		
DMO	VJ	Nov 21/13
ADM	JM	Nov 19/13
Dir./Mgr.	LL	15/11/18
Author	AM	15/11/15

DRAFT – NOT YET RELEASED

199481 Attachment
1_Information Bulletir

BRITISH COLUMBIA	Ministry of Energy and Mines *Issued: October 2013*	Renewable and Low Carbon Fuel Requirements Regulation **Approved Version of GHGenius** **Information Bulletin RLCF-011**

The Renewable and Low Carbon Fuel Requirements Regulation requires that the carbon intensities for the components of a fuel's lifecycle must be calculated using an "approved GHGenius".

Section 11.06 of the Regulation provides the Director with the authority to decide and approve the version of GHGenius used to calculate the carbon intensity of a fuel for a given compliance period.

For all fuels supplied in the compliance period July 1, 2013 to December 31, 2014, the approved GHGenius is GHGenius version 4.01.

GHGenius 4.03 has recently been released, and it contains significant improvements in the quality of data for the emissions from palm oil feedstock. Improved data from a U.S. EPA study of the palm oil industry as well as new data from the palm oil industry in Malaysia and Indonesia have caused significant changes in the carbon intensity of fuels made from undifferentiated palm oil. As a result, for all fuels supplied after December 31, 2014, the approved GHGenius will be GHGenius version 4.03 or later. The Director will approve the official version by July 1, 2014.

PLEASE NOTE: Any supplier who supplies fuel that has an approved carbon intensity posted on the Ministry's website must use the posted carbon intensity.

Need more information?

Please see the Renewable and Low Carbon Fuel website at: http://www.empr.gov.bc.ca/RET/RLCFRR or email us at lcfrr@gov.bc.ca

This information is for your convenience and guidance only, and does not replace or constitute a legal interpretation of the legislation. The *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act* and the Renewable and Low Carbon Fuel Requirements Regulation can be found on the Internet at: http://www.bclaws.ca

MINISTRY OF ENVIRONMENT
MEETING INFORMATION NOTE

November 14, 2013
File: 280-20
CLIFF/tracking #: 199206

PREPARED FOR: Honourable Mary Polak, Minister of Environment

DATE AND TIME OF MEETING: November 25, 11:00am

ATTENDEES: From Pembina Institute Josha MacNab, BC Regional Director and Matt Horne, Associate Director; Conferencing in: James Mack, Head, Climate Action Secretariat

ISSUES: Liquefied Natural Gas (LNG), Community Emission Reduction Opportunities, Particularly Buildings, and, BC's Carbon Tax.

BACKGROUND:

The Pembina Institute is a research, advocacy, and consulting organization. Their aim is to promote protection of Canada's environment, and transition to a clean energy future. Pembina is a key climate stakeholder and has an active role advising government on policy options as well as working with media on climate change issues.

DISCUSSION:

Topics for discussion may include:

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SUGGESTED RESPONSE:

s.13

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DMO	VJ	Nov 21/13
ADM	JM	Nov 18/13
Dir./Mgr.	LL	04/11/13
Author	HH	04/11/13

MINISTRY OF ENVIRONMENT
MEETING INFORMATION NOTE

July 29, 2013
File: 290-20
CLIFF/tracking #:196998

PREPARED FOR: Honourable Mary Polak, Minister of Environment

DATE AND TIME OF MEETING: September 9, 2013, 9:30 am

ATTENDEES: Paul Kariya, Clean Energy BC (see attached bio), Climate Action Secretariat representative

ISSUE(S): Clean Energy's role in liquefied natural gas and other northern development

BACKGROUND:

The Independent Power Producer (IPP) industry in BC was launched in 1989 when BC's Minister of Energy instructed BC Hydro to issue calls for proposals for private power. Currently, there are 70 IPPs operating in BC, which generate 12,600 GWh of electricity. The sector employs 1,800 full time employees and contributes $129 million to the province's GDP.

The mandate of the Clean Energy Association of British Columbia (CEBC), formerly known as the Independent Power Producers of British Columbia, is to develop a viable clean power industry in British Columbia that serves the public interest by providing cost-effective electricity through the efficient and environmentally responsible development of the Province's energy resources.

Paul Kariya of CEBC requested a meeting to discuss how clean energy can help the province achieve the goals listed in its jobs plan, particularly how it can foster northern development projects like the proposed liquefied natural gas (LNG) facilities. He had also requested further information about how BC will benchmark the cleanest LNG in the world. Clean Energy BC has met in the past with the previous Minister of Environment to discuss how clean electricity can be used to power the LNG industry at a comparable cost and lower emissions to using natural gas-produced electricity.

DISCUSSION:

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SUGGESTED RESPONSE:

s.13, s.12

Attachments: Appendix A: Paul Kariya Bio

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DM	WS	Sep 9/13
DMO	VJ	Aug 27/13
ADM	JM	Aug 26/13
ED	TL	Aug 2/13
Author	HP	Aug 1/13

Appendix A: Paul Kariya Bio

Paul Kariya is Executive Director of Clean Energy BC (formerly the Independent Power Producers Association of BC). Prior to this, he was Executive Director of Pacific Salmon Foundation.

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September 17, 2013
Cliff#: 198323

Meeting Bullets

PREPARED FOR: Honourable Mary Polak, Minister of Environment

MEETING: Merran Smith, Director, Tides Canada

DATE AND TIME OF MEETING: September 18, 2013 at 9:30am

BACKGROUND:

- British Columbia (BC) has identified the benefits provided by development of the natural gas sector, particularly those from the LNG sector. The full build out of BC LNG facilities could add $1 trillion cumulatively to BC GDP over 30 years. Already an estimated $1 billion has been spent on LNG infrastructure projects.
- BC has developed an LNG strategy with three pillars:
  - 1) keeping BC LNG firms competitive;
  - 2) maintaining leadership in climate policy and clean energy; and,
  - 3) keeping electricity rates affordable for BC families, communities and businesses.

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- Examples of the province's climate leadership initiatives include:
  - implementing North America's first revenue neutral carbon tax which contributed to an emission drop of 4.5% since 2007 while keeping provincial GDP slightly above the national average;
  - investing $1.8 billion research and development since 2001;
  - creating green venture capital funds like the Innovative Clean Energy (ICE) Fund;
  - setting a low-carbon fuel standard to promote bio fuel production;
  - achieving carbon neutrality within the public sector for the last three years, creating markets for green technologies, retrofits, and offsets; and,
  - facilitating lower-emission mining through the Northwest Transmission Line.

MINISTRY OF ENVIRONMENT
MEETING INFORMATION NOTE

August 29, 2013
File: 280-20
CLIFF/tracking #: 197652

PREPARED FOR: Honourable Mary Polak, Minister of Environment

DATE AND TIME OF MEETING: September 9, 2013 at 10:15 am

ATTENDEES: Nigel Protter and Tom Hackney, BC Sustainable Energy Association (BCSEA)

ISSUE(S): Introductory meeting with BCSEA regarding the Climate Action Plan, Greenhouse Gas (GHG) reduction targets, *Clean Energy Act*, Liquefied Natural Gas (LNG) Emissions, the Pacific Carbon Trust, and Enbridge pipeline.

BACKGROUND:

BCSEA is a non-profit association of citizens, professionals and practitioners working to promote the understanding, development and adoption of sustainable energy, energy efficiency and energy conservation in British Columbia. BCSEA participates in BC Utilities Commission reviews and stakeholder consultations on proposed energy policy.

Nigel Protter is Executive Director of BCSEA. Nigel has an MBA in innovation and sustainability and is a founder of businesses in ocean renewables and wave energy converter technology.

DISCUSSION AND SUGGESTED RESPONSE:

s.13, s.17

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DM	WS	Sept 3/13
DMO	VJ	Sept 3/13
ADM	JM	August 30/13
Dir./Mgr.	DP	August 29/13
Author	HHW	August 29/13

MINISTRY OF ENVIRONMENT
INFORMATION NOTE

September 3, 2013
File: 280-20
CLIFF #:197080

PREPARED FOR: Honourable Mary Polak, Minister of Environment

ISSUE: Upcoming publication of 2012 Industrial Greenhouse Gas Emissions Reports

BACKGROUND:

The *Greenhouse Gas Act* Reporting Regulation requires industrial operations to report annual greenhouse gas (GHG) emissions of 10,000 tonnes or more by March 31 of the following year. All reporting operations emitting 25,000 tonnes or more must also have reports verified by an accredited third party before submission. A reporting operation can encompass more than one individual facility in the case of electricity transmission and oil and gas extraction, processing and transmission activities.

The regulation was brought into force in 2009, with initial reports submitted for 2010 calendar year emissions. Data is collected for British Columbia via Environment Canada's One Window Reporting System thereby meeting legal requirements for reporting to both the provincial and federal government. Emission report summaries for 2010 and 2011 calendar year emissions have been published on the Ministry of Environment website.

The annual reports:

- Inform the public about significant sources of GHG emissions in British Columbia;
- Provide timely, accurate, quantitative information to support policy and program efforts to reduce GHG emissions; and,
- Inform public debate with quality data on emission sources, in particular relating to controversial issues such as fugitive emissions in natural gas production.

Ministry staff are preparing the public release of the 2012 emission report summaries.

DISCUSSION:

Highlights from the 2012 industrial greenhouse gas emissions reports include:

- There were 101 companies reporting with 123 reporting operations in BC;
- Industrial operations over 25,000 tonnes represent 30% of total provincial emissions (18.8 Mt CO_2e);
- Industrial emissions for all reporting operations were 0.5% lower in 2012 than 2011 (Table 1); and,
- Including emissions attributable to electricity imports (which are reported but not counted towards BC's greenhouse gas targets in accordance with international accounting procedures), total 2012 industrial greenhouse gas emissions were 4.1% lower than in 2011 (Table 1).

Table 1: BC Industrial Greenhouse Gas Emissions Summary (tonnes CO_2e)

Sector	2012	2011	% Change
Oil and Gas	10,140,000	10,513,000	-4
Cement and Lime	1,672,000	1,813,000	-8
Mining and Smelting	3,600,000	3,304,000	9
Electricity and Heat Generation	832,000	884,000	-6
Forest Products	1,738,000	1,693,000	3
Manufacturing and Refineries	861,000	768,000	12
Waste Treatment	427,000	385,000	11
BC Emissions Total	**19,270,000**	**19,360,000**	**- 0.5**
Electricity Imports	1,158,000	1,936,000	- 40
Reported Total	**20,428,000**	**21,296,000**	**- 4.1**

Companies and individual facilities with the largest greenhouse gas emissions in 2012 excluding wood biomass[1] and electricity imports are shown in Table 2 below.

Table 2: British Columbia's Largest Industrial Greenhouse Gas Emitters

Company	2012 CO_2e	Facility	2012 CO_2e
Spectra Energy Transmission	4.5 Mt	Fort Nelson Gas Plant, Spectra Energy Transmission	1.7 Mt
Teck Coal	1.6 Mt	Pine River Gas Plant, Spectra Energy Transmission	1.1 Mt
Canadian Natural Resources Limited	1.1 Mt	Kitimat Works, RioTinto Alcan	0.86 Mt

Electricity Imports

- Emissions were 1.2 Mt, or 40% less than in 2011, due to 2012 being a very high water year, meaning that less power needed to be brought into BC.
- Approximately 50% of imported electricity reported in 2012 was not used to serve BC Hydro customers and is instead immediately re-exported. Staff are considering modifying reporting procedures for future years to better reflect emissions associated with the actual consumption of imported electricity in BC.

Oil and Gas

- The 4% decrease in greenhouse gas emissions in the oil and gas sector is likely related to a 1.1% drop in overall production, an increase in the amount of low CO_2 gas extracted from the Montney Basin, and a decrease in the amount of higher CO_2 gas from conventional basins. The emissions intensity of production in the oil and gas sector has decreased by a further 3% in 2012 beyond the 8% drop seen from 2010 to 2011.

[1] Emissions from wood biomass listed in Schedule C of the regulation are currently excluded from facility emission totals as they have historically been considered 'carbon neutral'. This accounting treatment may change as international accounting procedures are revised. In 2012 wood biomass emissions were 14.6 Mt CO_2e.

Mining and Smelting

- The 9% increase in emissions in the mining and smelting sector is due in large part to increased production at a number of coal mines.
- Overall, the increases in emissions in the mining and smelting sector is compensated for by decreases in the oil and gas, cement, lime and electricity import sectors, resulting in a small decrease in total provincial industrial greenhouse gas emissions.

Verification Results

- For the 2012 emissions year, the Director will be publishing the results of the verification statements (this will be the first time this has been done). The purpose of this is to enhance public transparency and help ensure compliance.

NEXT STEPS:

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Attachment: Appendix A, 2012 Reporting Operation GHG Emissions

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DM	WS	Sept 16/13	
DMO	VJ	Sept 5/13	
ADM	JM	Sept 4/13	Sept 3/13
ED	LL	Sept 4/13	Sept 3/13
Author	DP	Aug 14/13	Sept 3/13

Appendix A: 2012 Reporting Operation GHG Emissions

Company	Facility	Facility Type	Tonnes CO_2 from Biomass	Total tonnes CO_2e excluding biomass
Aitken Creek Gas Storage ULC	Aitken Creek Gas Storage ULC	LFO	0	50470
Alliance Pipeline Ltd.	BC Pipeline System (LFO)	LFO	0	25262
	aggregated facilities <10,000 t	I_bc	0	1106
	Taylor Compressor Station	IF_a	0	24156
AltaGas Ltd.	ALA BC LFO	LFO	0	38694
	aggregated facilities <10,000 t	I_bc	0	3227
	Blair Creek Comp Stn d-058-F	IF_a	0	21552
	Younger NGL Extraction Plant	IF_a	0	13915
Apache Canada Ltd.	NEBC Operations & Drilling	LFO	0	88148
	aggregated facilities <10,000 t	I_bc	0	77226
	Noel 7729	IF_a	0	10922
ARC Resources	ARC BC LFO	LFO	0	119922
	aggregated facilities <10,000 t	I_bc	0	64635
	Dawson Comp Stn 01-34	IF_a	0	20652
	Dawson Sour Gas Plant 05-35	IF_a	0	16836
	Parkland Comp Stn 08-13	IF_a	0	17798
Artek Exploration Ltd.	Artek Inga 15-03-088-23W6M	LFO	0	19131
Aux Sable Canada L.P.	Aux Sable BC LFO	LFO	0	26734
	aggregated facilities <10,000 t	I_bc	0	120
	Septimus Sweet Gas Plant 12-27	IF_a	0	26615
Baytex Energy	LFO Facility	LFO	0	18453
	aggregated facilities <10,000 t	I_bc	0	18453
Bonavista Energy Corporation	Bonavista BC LFO	LFO	0	64624
	aggregated facilities <10,000 t	I_bc	0	30037
	Bonavista Blueberry D-50-C/94-A-13	IF_a	0	12130
	Nig Creek A-94-B/94-H-4	IF_a	0	12174
	Umback D-36	IF_a	0	10283
British Columbia Hydro and Power Authority	Burrard Generating Station	SFO	0	24427
	Fort Nelson Generating Station	SFO	0	128285
	Masset Diesel Generating Station	SFO	0	19285
	BC Hydro Transmission and Distribution System	LFO	0	46975
	aggregated facilities <10,000 t	I_bc	0	46975
Canadian Autoparts Toyota Inc.	Canadian Autoparts Toyota	SFO	0	18043
Canadian Forest Products Ltd	Canfor Taylor Pulp	SFO	0	64622
	Elko Sawmill	SFO	0	19028
	Plateau Sawmill	IF_a	0	7864
	Prince George Sawmill	IF_a	0	3870

Company	Facility	Facility Type	Tonnes CO_2 from Biomass	Total tonnes CO_2e excluding biomass
Canadian Natural Resources Limited	CNRL BC LFO	LFO	0	1066803
	aggregated facilities <10,000 t	I_bc	0	812856
	Babcock Comp Stn D-099-E	IF_a	0	11825
	Buckinghorse Comp Stn D-044-A	IF_a	0	10049
	Buick South Comp Stn D-078-I	IF_a	0	12367
	Cypress B-099-C Sour Gas Plant	IF_a	0	13024
	Graham Comp Stn C-076-K	IF_a	0	12344
	Jedney Comp Stn A-062-E	IF_a	0	13102
	July Lake Comp Stn A-071-G	IF_a	0	19374
	Ladyfern B-017-I Gas Plant	IF_a	0	23080
	Ladyfern Comp Stn B-088-H	IF_a	0	14399
	Murray River Comp Stn C-033-J	IF_a	0	33122
	S. Buick Oil Battery D-078-I	IF_a	0	11288
	Stoddart 02-34 Sour Gas Plant	IF_a	0	70323
	Velma Comp Stn B-088-D	IF_a	0	11179
Canexus Corporation	North Vancouver Chlor-alkali Facility	SFO	0	10244
Canfor Pulp Limited Partnership	Northwood Pulp Mill	SFO	1690844	113863
	Prince George Pulp and Paper and Intercontinental Pulp Mills	SFO	1652972	162666
Cariboo Pulp and Paper Company	Cariboo Pulp and Paper Company	SFO	1141999	105933
Catalyst Paper Corporation	Crofton Division	SFO	1373417	164472
	Port Alberni Division	SFO	397484	28851
	Powell River Division	SFO	701764	98021
Central Global Resources ULC	Central global (LFO)	LFO	0	2804
	aggregated facilities <10,000 t	I_bc	0	2804
CENTRAL HEAT DISTRIBUTION LIMITED	CENTRAL HEAT DISTRIBUTION LIMITED	SFO	0	96399
CertainTeed Gypsum Canada Inc	Vancouver Wallboard Plant	IF_a	0	24713
Chevron Canada Limited	Burnaby Refinery	SFO	0	509831
Chinook Energy (2010) Inc.	Boundary Lake (LFO)	LFO	0	47154
	aggregated facilities <10,000 t	I_bc	0	34909
	Boundary Lake 8-12	IF_a	0	12358
CIPA Lumber Co. Ltd.	CIPA Lumber Co. Ltd.	SFO	0	26987
City of Vancouver	Vancouver Landfill	SFO	0	34345
Coastland Wood Industries Ltd.	Coastland Wood Industries Ltd., Annacis Division	SFO	0	14653
Conifex Inc.	Conifex Inc. (SFO)	SFO	139210	16905
ConocoPhillips Canada Resources Corp.	ConocoPhillips Canada Linear Facility	LFO	0	404903
	aggregated facilities <10,000 t	I_bc	0	284308
	Brassey Comp Station D-013-F	IF_a	0	18042

Company	Facility	Facility Type	Tonnes CO_2 from Biomass	Total tonnes CO_2e excluding biomass
	Hiding Creek Comp Station B-053-A	IF_a	0	18798
	Hiding Creek Comp Station D-039-G	IF_a	0	19380
	Noel Sweet Gas Plant	IF_a	0	48331
	Ring Border Sweet Gas Plant	IF_a	0	16042
Crew Energy Inc.	Crew BC LFO	LFO	0	26399
Crew Energy Inc.	aggregated facilities <10,000 t	I_bc	0	26396
Devon Canada Corporation	Devon BC LFO	LFO	0	173957
	aggregated facilities <10,000 t	I_bc	0	110990
	DEVON ARL KOMIE C-100-G/094-O-08	IF_a	0	13170
	Martin Creek A-033	IF_a	0	10548
	Tommy Lakes C-019	IF_a	0	18611
	Wargen D-056	IF_a	0	20637
Domtar Inc.	Kamloops Mill (SFO)	SFO	1772560	114909
Dunkley Lumber Ltd.	Dunkley Lumber Ltd.	SFO	0	21466
Encana Corporation	Encana BC LFO	LFO	0	848604
	aggregated facilities <10,000 t	I_bc	0	320257
	Cabin Comp Stn a-052-J	IF_a	0	10811
	Cutbank Comp Stn A-038-I	IF_a	0	28170
	Cutbank Comp Stn A-062-I	IF_a	0	11195
	Cutbank Comp Stn B-100-B	IF_a	0	18921
	Cutbank Comp Stn c-029-A	IF_a	0	13315
	Cutbank Comp Stn d-073-B	IF_a	0	10899
	Dawson Creek Comp Stn 09-15	IF_a	0	34637
	Elleh Sweet Gas Plant	IF_a	0	23595
	Gunnell Comp Stn b-023-F	IF_a	0	19938
	Horn River Comp Stn c-067-K	IF_a	0	86198
	Hythe Comp Stn A-005-G	IF_a	0	48311
	Hythe Comp Stn a-029-H	IF_a	0	27017
	Hythe Comp Stn D-019-H	IF_a	0	30017
	Hythe Comp Stn D-033-I	IF_a	0	32051
	Kiwigana Comp Stn C-093-L	IF_a	0	19905
	Midway Comp Stn b-065-B	IF_a	0	11392
	Sierra Sour Gas Plant	IF_a	0	102397
Enerplus Corporation	Enerplus Linear Facility	LFO	0	52859
	aggregated facilities <10,000 t	I_bc	0	24367
	West Tommy Lakes Booster Station 1 C-028-K	IF_a	0	13264
	West Tommy Lakes Comp Station 3 A-029-I	IF_a	0	15227
EOG Resources Canada Inc.	EOG BC LFO	LFO	0	53117
	aggregated facilities <10,000 t	I_bc	0	17267
	Gote Comp Stn C-018-B	IF_a	0	11393

Company	Facility	Facility Type	Tonnes CO_2 from Biomass	Total tonnes CO_2e excluding biomass
	Maxhamish Comp Stn d-036-I	IF_a	0	24454
FMC of Canada Ltd	FMC of Canada Ltd	SFO	0	37980
FortisBC Energy (Vancouver Island) Inc.	FortisBC Energy Vancouver Island	LFO	0	45870
	aggregated facilities <10,000 t	I_bc	0	17918
	V1 Compressor Station, Eagle Mountain, Coquitlam	IF_a	0	27952
FortisBC Energy Inc.	FortisBC Energy Inc.	LFO	0	88466
	aggregated facilities <10,000 t	I_bc	0	88466
Gibraltar Mines Ltd.	Gibraltar Mine (SFO)	SFO	0	70662
Graymont Western Canada Inc.	Pavilion Plant	SFO	0	113219
Greater Vancouver Regional District	Annacis Island Wastewater Treatment Plant	SFO	0	22029
	Iona Island Wastewater Treatment Plant	SFO	0	14398
Greater Vancouver Sewerage and Drainage District	Metro Vancouver Waste-to-Energy Facility	SFO	0	310713
HARVEST OPERATIONS CORP.	Harvest BC Linear Facility Operations	LFO	0	23548
	aggregated facilities <10,000 t	I_bc	0	2098
	Hay Gas Plant	IF_a	0	21450
Houweling Nurseries Ltd.	Houweling Nurseries Ltd. - Delta	SFO	0	14027
Howe Sound Pulp & Paper Corporation	Howe Sound Pulp and Paper Mill	SFO	1427469	107565
Husky Oil Operations Limited	Prince George Refinery	SFO	0	135683
	Husky Oil Operations BC Linear Facilities Operation	LFO	0	125621
	aggregated facilities <10,000 t	I_bc	0	49400
	BIVOUAC B-099-H/094-I-08	IF_a	0	14270
	Sierra Gas Plant	IF_a	0	61946
Imperial Metals Corporation	Mount Polley Mine	SFO	0	41826
Imperial Oil Resources	Imperial Oil Resources BC Linear Facility Operation	LFO	0	56116
	aggregated facilities <10,000 t	I_bc	0	45576
	Boundary Lake Gas Plant (BC GP 0045)	IF_a	0	10541
Keyera Corp	Keyera BC LFO	LFO	0	37821
	aggregated facilities <10,000 t	I_bc	0	805
	Caribou Sour Gas Plant c-004-G	IF_a	0	37014
Kruger Products L.P.	Kruger Products L.P.	SFO	38732	27194
Lafarge Canada Inc.	Kamloops Plant	SFO	0	129541
	Richmond Cement Plant	SFO	0	763469
Lantic Inc. - Vancouver Refinery	Lantic Inc. - Vancouver Refinery	SFO	0	25724
Lehigh Hanson Materials Ltd.	Delta Plant	SFO	0	589549
LHOIST NORTH AMERICA OF CANADA INC.	Langley Plant	SFO	0	67291

Company	Facility	Facility Type	Tonnes CO_2 from Biomass	Total tonnes CO_2e excluding biomass
Lone Pine Resources Canada Ltd.	Lone Pine BC LFO	LFO	0	19601
	aggregated facilities <10,000 t	I_bc	0	19599
Mackenzie Pulp Mill Corporation	Mackenzie Pulp Mill	SFO	564301	110247
Maxim Power Corp	Hartland Landfill	SFO	0	11176
	Vancouver LandFill Delta	SFO	0	14545
Moly-Cop Canada	Moly-Cop Canada	SFO	0	16229
Murphy Oil Company Ltd	LFO	LFO	0	176914
	aggregated facilities <10,000 t	I_bc	0	19937
	5-1-77-17W6	IF_a	0	99513
	Tupper A-21-B/093-09-P	IF_a	0	57464
NAL Energy Ltd.	NAL BC Linear Facilities Operation (LFO)	LFO	0	22006
	aggregated facilities <10,000 t	I_bc	0	8406
	NAL Fireweed C-A-16-A/94-A-13	IF_a	0	13570
Nanaimo Forest Products Ltd.	Harmac Pacific Operations	SFO	1066283	78837
Neucel Specialty Cellulose	Neucel Specialty Cellulose (SFO)	SFO	364238	165011
New Gold	New Afton Mine	SFO	0	13224
Nexen Inc.	Nexen BC Operations (LFO)	LFO	0	91628
	aggregated facilities <10,000 t	I_bc	0	34687
	Etsho North Compressor Station	IF_a	0	46065
	Tsea D-07-I C/S	IF_a	0	13587
NuVista Energy Ltd.	NuVista BC LFO	LFO	0	62236
	aggregated facilities <10,000 t	I_bc	0	30398
	Black Conroy Comp Stn b-094-J	IF_a	0	12443
	Martin Creek Sour Gas Plant b-002-E	IF_a	0	19395
Pacific Northern Gas Ltd.	PNG (LFO)	LFO	0	22888
	aggregated facilities <10,000 t	I_bc	0	22894
Peace River Coal Inc.	Trend Mine (SFO)	SFO	0	107786
Pengrowth Energy Corporation	Pengrowth BC Linear Facilities Operation (LFO)	LFO	0	61010
	aggregated facilities <10,000 t	I_bc	0	51574
	Groundbirch Gas Plant	IF_a	0	11201
Penn West Petroleum Ltd	BCBT000 (PENN WEST LFO)	LFO	0	261323
	aggregated facilities <10,000 t	I_bc	0	53313
	BCBT00002487 (Firebird)	IF_a	0	11412
	BCBT00002917 (Wildboy Battery)	IF_a	0	42810
	BCGP00002917 (Wildboy Gas Plant)	IF_a	0	114835
PetroBakken Energy Ltd.	Petrobakken BC Linear Facility Operations	LFO	0	14683
	aggregated facilities <10,000 t	I_bc	0	14683
Polar Star Canadian Oil and Gas Inc.	Conroy LFO	LFO	0	22551
	aggregated facilities <10,000 t	I_bc	0	5001

Company	Facility	Facility Type	Tonnes CO_2 from Biomass	Total tonnes CO_2e excluding biomass
	Conroy D-48-C/94-H-12	IF_a	0	15679
	Conroy D-80-F/94-H-12	IF_a	0	1870
Progress Energy Canada Ltd.	Progress 2012 Linear Facilities Operation	LFO	0	383986
	aggregated facilities <10,000 t	I_bc	0	277964
	BLUEBERRY c-29-K/94-A-12	IF_a	0	15159
	BLUEBERRY d-87-D/94-A-13	IF_a	0	10982
	Bubbles C-079-A/094-G-08	IF_a	0	12606
	BUBBLES d-047-A/094-G-8	IF_a	0	14715
	JEDNEY NORTH b-76-C/94-G-8	IF_a	0	12216
	PROGRESS NE GUNDY A-058-H/094-B-16	IF_a	0	21197
	Progress Town South D-059-J/094-B-16	IF_a	0	17700
	West Gundy C-86-J/094-B-9	IF_a	0	10793
Quicksilver Resources Canada Inc.	Fortune Creek LFO	LFO	0	43422
	aggregated facilities <10,000 t	I_bc	0	582
	Fortune Creek Compressor Station	IF_a	0	42841
QUINSAM COAL COPORATION	QUINSAM COAL CORP	SFO	0	16473
Ramshorn Canada Investments limited	Ramshorn Canada LFO	LFO	0	22912
	aggregated facilities <10,000 t	I_bc	0	3514
	Tattoo Compressor Station	IF_a	0	19399
Rio Tinto Alcan	Kitimat Works	SFO	0	859120
Shell Canada Limited	Shell British Columbia LFO	LFO	0	224231
	aggregated facilities <10,000 t	I_bc	0	20206
	Brassey Gas Processing and Production IF-a	IF_a	0	22485
	Groundbirch Gas Processing and Production IF-a	IF_a	0	12456
	Montney Gas Processing and Production IF-a	IF_a	0	138166
	Sundown Gas Processing and Production IF-a	IF_a	0	11023
	Sunset Gas Processing and Production IF-a	IF_a	0	20216
Spectra Energy Midstream Corporation	BC Midstream (LFO)	LFO	0	278398
	Highway Gas Plant	IF_a	0	56548
	Jedney I Gas Plant	IF_a	0	54095
	Jedney II Gas Plant	IF_a	0	56854
	Peggo Plant	IF_a	0	19672
	Tooga Plant	IF_a	0	26324
	West Doe Plant	IF_a	0	64900
Spectra Energy Transmission	McMahon Cogen Plant	SFO	0	487230
	SET PLFS (LFO)	LFO	0	4004465
	aggregated facilities <10,000 t	I_bc	0	41124
	Booster Station 12 - Fort Nelson	IF_a	0	24926

Company	Facility	Facility Type	Tonnes CO_2 from Biomass	Total tonnes CO_2e excluding biomass
	Booster Station 19 - Cabin Lake	IF_a	0	43265
	Booster Station 3 - Kobes Creek	IF_a	0	24545
	Booster Station 6 - Bluehills	IF_a	0	26327
	Dawson Plant	IF_a	0	27394
	Fort Nelson Gas Plant	IF_a	0	1683922
	Kwoen Gas Plant	IF_a	0	15235
	McMahon Gas Plant	IF_a	0	342385
	Pine River Gas Plant	IF_a	0	1051898
	Station 1 - Taylor	IF_a	0	43892
	Transmission Mainline	IF_a	0	679552
Suncor Energy Inc.	Suncor BC Linear Facility Operation	LFO	0	168702
Suncor Energy Products Partnership	Burrard Products Terminal	SFO	0	12071
Talisman Energy Inc.	Talisman Energy	LFO	0	249334
	aggregated facilities <10,000 t	I_bc	0	107622
	Talisman Farrell Creek	IF_a	0	55307
	Talisman Ojay	IF_a	0	21105
	Talisman West Sukunka	IF_a	0	26368
Taqa North Ltd.	TAQA BC LFO	LFO	0	59224
	aggregated facilities <10,000 t	I_bc	0	21593
	TAQA CHINCHAGA C-32-H/94-H-8	IF_a	0	18502
	TAQA LAPRISE A-40-E/94-H-5	IF_a	0	19128
Teck Coal Limited	Coal Mountain Operations	SFO	0	173834
	Elkview Operations	SFO	0	355254
	Fording River Operations	SFO	0	475451
	Greenhills Operations	SFO	0	411293
	Line Creek Operations	SFO	0	159059
Teck Highland Valley Copper Partnership	Teck Highland Valley Copper Partnership	SFO	0	154903
Teck Metals Ltd, Trail Operations	Teck Metals Ltd, Trail Operations	SFO	3299	437863
Tembec	Chetwynd Operations	SFO	147402	18600
	Tembec Skookumchuck Operation	SFO	864000	63565
Terra Energy Corporation	Terra (LFO)	LFO	0	45334
	aggregated facilities <10,000 t	I_bc	0	45512
THOMPSON CREEK MINING LTD.	Endako Mine	SFO	0	32591
Tolko Industries Ltd.	Heffley Creek Division	SFO	26635	14766
	Lavington Planer Mill	SFO	0	17289
	Nicola Valley Division	SFO	0	13743
Tourmaline Oil Corp	Tourmaline LFO	LFO	0	80836
	aggregated facilities <10,000 t	I_bc	0	1626
	Dawson/Doe 1-32-80-15 W6	IF_a	0	35003

Company	Facility	Facility Type	Tonnes CO_2 from Biomass	Total tonnes CO_2e excluding biomass
	Sunrise 3-18-80-17 W6	IF_a	0	44386
TransCanada PipeLines Ltd.	TransCanada Pipeline, British Columbia System	LFO	0	226894
	aggregated facilities <10,000 t	I_bc	0	1850
	ANG Crowsnest	IF_a	0	118651
	ANG ELKO	IF_a	0	31002
	ANG MOYIE	IF_a	0	55034
Tree Island Industries Ltd	Tree Island Industries	SFO	0	11397
V.I. Power LP	Island Generation Inc	SFO	0	29745
Veresen Energy Infrastructure Inc.	Veresen BC linear Facility (LFO)	LFO	0	80126
	Steeprock Sour Gas Plant	IF_a	0	80126
Village Farms Canada L.P.	Village Farms - Delta I	SFO	0	22726
	Village Farms Canada - Delta II	SFO	0	9888
Walter Canadian Coal Partnership	Dillon / Brule Mine	SFO	0	115035
	Willow Creek Mine	SFO	0	74874
	Wolverine Group- Perry Creek Mine	SFO	0	100872
Wastech Services LTD.	Cache Creek Landfill	SFO	0	19806
West Coast Reduction Ltd.	West Coast Reduction Ltd.	SFO	0	22810
West Fraser Mills Ltd.	Quesnel River Pulp	SFO	0	53416
Weyerhaeuser Company Limited	iLevel By Weyerhaeuser Princeton Sawmill	SFO	0	20182
Windset Farms Inc.	Windset Greenhouses - Ladner	SFO	0	26563
Zellstoff Celgar Limited Partnership	Zellstoff Celgar Limited Partnership	SFO	1236613	95011

MINISTRY OF ENVIRONMENT
INFORMATION NOTE

August 29, 2013
File: 280-30
CLIFF/tracking #: 197610

PREPARED FOR: Honourable Mary Polak, Minister of Environment

DATE AND TIME OF MEETING: September 24 at 3:45 p.m.

ATTENDEES: MaryAnne Arcand, Chair & CEO, Carbon Offset Aggregation Cooperative; and James Mack, Head, Climate Action Secretariat

ISSUE: Carbon Offset Aggregation Cooperative (COAC) Diesel Reduction Program

BACKGROUND:

The Prince George-based Carbon Offset Aggregation Cooperative offers a program to assist companies operating heavy diesel trucks and equipment to reduce greenhouse gas emissions and generate carbon offsets. By using less fuel more efficiently, COAC members have fuel savings of up to 30% and generate carbon offsets. The COAC program enables owners to create, aggregate and sell, transfer, or trade carbon offsets. The proceeds of the sale of the offsets are returned to the member producer as a dividend, less a percentage for COAC's administration.

COAC received funding under the Province's Clean Transportation Initiatives to launch a program with truckers to reduce their fuel consumption. COAC also started the Forest Carbon Partnerships program that is financing replanting of trees using carbon credits using the Forest Carbon Offset Protocol the government released in 2011. In 2012, Environment Minister Terry Lake announced $2 million in funding for COAC. The purpose of the funding was to be seed money to assist COAC in providing more members with low-interest loans to retrofit their heavy duty diesel trucks and equipment to increase fuel efficiency, save money and reduce carbon emissions.

DISCUSSION:

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SUGGESTED RESPONSE:

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DMO	VJ	09/10/2013
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A/ED	JV	09/04/2013
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