Legislative Assembly of Alberta

The 28th Legislature
First Session

Standing Committee on Resource Stewardship

Natural Gas Production
Stakeholder Presentations

Monday, October 28, 2013
6:16 p.m.

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Standing Committee on Resource Stewardship

Participants

6:16 p.m. **Monday, October 28, 2013**

[Ms Kennedy-Glans in the chair]

The Chair: Welcome, everyone. I apologize for starting a little bit late here, especially for our guests from out of town. My name is Donna Kennedy-Glans. I'm chair of this committee and the MLA for Calgary-Varsity.

We can go around the room, and I would ask our guests as well to introduce themselves as we go around the table. I was going to begin with my vice-chair, but we'll finish up with him.

Ms Fenske.

Ms Fenske: Thank you. Jacquie Fenske, MLA, Fort Saskatchewan-Vegreville.

Mr. Casey: Ron Casey, MLA, Banff-Cochrane.

Mr. Webber: Len Webber, MLA, Calgary-Foothills.

Ms L. Johnson: Welcome. Linda Johnson, Calgary-Glenmore.

Mr. Bilous: Good evening. Deron Bilous, MLA, Edmonton-Beverly-Clareview.

Ms Kubinec: Good evening. MLA Maureen Kubinec, Barrhead-Morinville-Westlock.

Ms Koskie: I'm Sarah Koskie, a government relations adviser with EnCana.

Mr. Foreman: Kellen Foreman. I also work at EnCana.

Mr. Sendall: I'm Richard Sendall. I'm senior vice-president for strategy and government relations with MEG Energy. I'm here today representing the In Situ Oil Sands Alliance.

Mr. Walter: Good evening. I'm Fred Walter, also with MEG Energy and supporting the In Situ Oil Sands Alliance.

Mr. Barnes: Drew Barnes, MLA, Cypress-Medicine Hat.

Mr. Bikman: Gary Bikman, MLA, Cardston-Taber-Warner.

Mr. Hale: Jason Hale, MLA, Strathmore-Brooks.

Mr. Stier: Pat Stier, MLA, Livingstone-Macleod.

Dr. Swann: Good evening. David Swann, Calgary-Mountain View.

Ms Zhang: Nancy Zhang, legislative research officer.

Dr. Massolin: Good evening. Philip Massolin, manager of research services.

Mr. Tyrell: Chris Tyrell, committee clerk.

Mr. Anglin: Joe Anglin, MLA, Rimbey-Rocky Mountain House-Sundre.

The Chair: Who do we have on the phone tonight?

Mr. Lemke: Ken Lemke, MLA, Stony Plain.

Mr. Sandhu: Peter Sandhu, Edmonton-Manning.

The Chair: All right. Wonderful.

We apologize for eating in front of you, folks, but we just got out of the House, so it's kind of a necessity. We thank you for that tolerance.

The microphone consoles are operated by *Hansard*, so we don't need to touch them. Again, if you've got a BlackBerry or cellphone, just tuck it under the table. It'll probably have less interference. Just to remind everyone that everything is recorded by *Hansard* and is available.

I'm going to start with approval of the agenda. Would someone move that the agenda for the October 28, 2013, meeting of the Standing Committee on Resource Stewardship be adopted as circulated? I will let you do that, sir. Thank you.

Mr. Bikman: Just got to get my name on the record once this year.

The Chair: Mr. Bikman. Thank you. All in favour? Any objections? Motion carried.

Next we need to look at the minutes from the last meeting. If someone would move that the minutes of the October 23, 2013, meeting of the Standing Committee on Resource Stewardship be adopted as circulated. Mr. Webber?

Mr. Sandhu: Madam Chair, I'll do that.

The Chair: Oh, Mr. Sandhu. I'll let you do that instead. Thank you.

Mr. Sandhu: Thank you.

The Chair: All in favour? Any objections? Carried.

All right. Now the really important part of this meeting. We've been hearing from different stakeholders who are involved in some way, shape, or form with natural gas in Alberta. It's a very ambitious goal that we've set for our committee, to kind of look at the several levers and ways to better monetize the value of natural gas in this province, something which I'm sure you do on a daily basis. We have until 8 o'clock this evening because the House is not sitting, which is kind of a luxury for us – normally it's one hour – and we want to hear your perspective as long-standing gas producers in this province.

We will ask questions after your presentations, and we would give each team about 20 minutes to make a presentation. You've got a slide deck. Does everybody have a copy of the slide deck in front of them?

Mr. Lemke and Mr. Sandhu, do you have a copy of the slide decks?

Mr. Sandhu: I don't.

The Chair: Okay. Maybe we can get them to you.

Mr. Lemke: Yes, I do.

The Chair: All right.

I will turn it over to the team from EnCana. Thank you.

EnCana Corporation

Mr. Foreman: Well, first of all, thanks for the opportunity. We'll go through this presentation. I guess, Donna, as you mentioned, you're wanting to hear a little bit more about some of the levers, so near the end I think I'll focus a little bit on what things our industry needs and is looking for from government, from regulators, et cetera, and what, you know, our plans are in the market and what the opportunities are. I appreciate you letting us come talk to you.

I guess we've already gone through intros, but once again, I'm Kellen Foreman. I'm a group lead on the regulatory group at our company. This is Sarah.

Ms Koskie: Hello. I'm a government relations adviser for EnCana.

Mr. Foreman: We won't go through the details on this slide, but the summary of the presentation that we're going to go through is talking a little bit about unconventional and shale gas. That's kind of where the natural gas industry is going. I'll get into why unconventional and shale are really the future of natural gas all over North America, but for those of you who aren't familiar, it's a changing game in the natural gas world, so that's where things are going. I'll talk about markets, how that relates to LNG, and then get a bit into some of the social licence aspects of developing natural gas. At the end of it I'll get into some of the strategies we have around targeting liquids, rich natural gas plays, how that's going to impact LNG, et cetera.

Just to give you a little bit of perspective on EnCana, I'll spend some time on this slide. This slide is looking at the major plays that EnCana is focused on. Going forward, there are three major areas of unconventional gas that are the focus of our company and many other companies in Alberta. There's the Duvernay play, which is a very brand new play. It's a shale play, and we'll spend some time talking about that. As well, there's the Deep Basin, which internally we call Bighorn, and Peace River arch, which constitutes the Montney play. Those are really the three big unconventional natural gas plays right now in Alberta. I'll spend some time focusing on all of those and how they're going to play a role in the market in LNG, et cetera.

To differentiate the terms "conventional" versus "unconventional," over the past 50 years industry has really been focused on conventional. When you're looking at this cartoon – this is going back 300 million years – those beaches, the riverbeds, the deltas, et cetera, are where the conventional resources have always been found. They're usually made out of sandstone, et cetera, from these beaches, and the gas has big pockets to sit in and permeate through when we're chasing it. Those resources are much easier to capture when you drill wells and such. Over the last 50 years we've exploited a great amount of those resources.

The future, when you look at this picture, is in that deep marine. It's the bottom of the ocean there, and that's where a lot of this organic material has kind of settled. It sits in huge, thick, very vast, continuous reservoirs. So the resource has been there all along, but it's not until kind of the last five, six years that we've unlocked the potential and developed the technology to exploit some of those resources and capture those. The organic material is just too dense. The words we use are "permeable" and "porosity," but it's just too thick, and there are no paths for the gas to migrate through. Now that we have hydraulic fracturing and horizontal drilling, what we're chasing, really, is what's at the bottom of the ocean there. It's those big, thick, vast plays. They're very continuous and very big.

Looking at a picture of North America 300 million years ago, you can see where some of those plays lie: the Horn River, the Duvernay, the Bakken, and the Marcellus. They're a little bit off the land, and they're where all these organic sediments have kind of deposited at the bottom of the ocean. That's what we're chasing now, and that's really the future.

6:25

Here's just a quick snapshot, really, of our life cycle when we're developing a play. When we're going to look at a play – and I'll focus on these three plays because they're the big ones for natural gas in the province. Each of these plays is at a different stage in their life, and you can see on the very far left-hand side that we've tried to capture what percentage of the wells get drilled in each of those stages.

The purpose of this slide is to show that the Duvernay and the Montney, although there is some production coming from them, are at very, very early stages in their life right now. We're still in a pilot phase. There's huge potential. We've mapped out the resource. We know what's underground, but we're still in a situation where we're trying to make these things commercial. There are high costs, et cetera, to these things. You can see the Duvernay, where we're sitting at. You know, 1 to 2 per cent of the resource has been captured to date, so there's a huge potential there. We're still trying to figure out exactly how to do this best and make it commercial. The Montney is a little bit further ahead, but there's still a lot of work to be done. The Deep Basin is an unconventional play, but it's a little bit more sandstone. It's a little easier to capture that resource, and it's been developed over the last, you know, 15, 20 years, so we're a little bit further ahead in the Deep Basin.

I guess the message here is that the Duvernay and the Montney are two very huge resource potentials in Alberta. They're both very liquids-rich gas plays. I'll talk about the liquids-rich aspect in a bit. They're huge plays with lots of potential, and it's going to be very important in these early days to make sure that there are proper regulations, royalties, incentives, that there's an environment in which we can start chasing these things now and get them to the commercial phase so that they don't get pushed to the wayside when LNG and market situations get figured out.

I'll get through some of these slides pretty quickly. This is the kind of development that we do in these major plays. In the past we used to do a lot of vertical drilling, but pad drilling is really the future in natural gas, especially in these unconventional areas. You can see here that from one particular pad we can drill up to 16 different wells. All of these wells are up to two and a half kilometres of lateral length once they get into the zone of interest. What's unlocking this resource is, well, one, the horizontal wells, but, two, that it's really using hydraulic fracturing along that lateral length at the bottom there to unlock and create those pathways so that the natural gas and any liquids in there can flow into the wellbores. Without hydraulic fracturing these wells can't be drilled, and nothing will come into them. It's hydraulic fracturing that's cracking and opening up and creating those pathways, so that's the technology, really, that's unlocked these resources.

Here's just a quick snapshot, a top view of a drilling operation. This is in the Duvernay play, and this is just a top view of how big the lease really is. In this case it's about 250 metres by 250 metres. There's potential to drill up to 16 wells in that area. This is what it's going to look like during the drilling phase, and this is what that same lease is going to look like during the completion phase. So we could spend up to six months drilling. Drilling kind of hands the wells over to completions, and this is where that new technology of multistage hydraulic fracturing is taking place.

You can see that there are about 15 pumping trucks all kind of around that wellhead in the centre of the lease. Those are the trucks that we're using to do the hydraulic fracturing, to pump our fluid, which is 99 per cent water in this case here. We're pumping water for the most part and a little bit of sand into these wellbores to create those fractures and cracks. It's a very co-ordinated approach. This is an example of how much equipment we have on site and how condensed it can get. We try to keep our leases as absolutely small as possible, but they do have to be a certain size just so we can manoeuvre trucks around. It's a very co-ordinated approach, and we're doing our best on the environmental side in terms of surface impacts.

On the next slide here you can see that exact same lease, and this is what it looks like when the operation is done. So, yes, there's a little clearing in there, but there's not going to be a whole lot of equipment. For the natural gas side it's primarily just a couple of wellheads connected to a header in a pipeline, and that pipeline heads off to kind of a centralized battery. You can see on the right that there's a little road coming in. That's going to stay there for, I guess, the life of the wells, which could be up to 30 years. On the left you can see a pathway that was cleared for the pipeline. That's going to grow in and in most cases get replanted, so after a number of years you won't really see that pathway as much. But this is what the well is going to look like for the next 30 years.

I'll hand it over to Sarah, and she can talk a little bit about the social aspects of our development.

Ms Koskie: Sure. As you saw from the slides that Kellen just showed, they're highly active sites with a lot of trucks and traffic, so you know, to mitigate some of the concerns that the landowners and stakeholders in the area are undergoing, this is an example of what EnCana's program Courtesy Matters looks like, which is where we try to minimize the noise and the dust and the traffic and do things like making sure that we don't have any heavy trucks going to the leases when school buses are driving and that type of thing.

Industry is also working together. CAPP has put together some hydraulic fracturing practices, and all of industry has really signed on to these practices. They are mandating things like fracturing fluid disclosure, as you can see up there, and finding alternative water sources and baseline groundwater testing and those types of things.

An example of what EnCana is doing specifically on the CAPP hydraulic fracturing practices can be found with our DeBolt plant, which this next slide takes a look at. This is our saline water plant that we've developed in partnership with Apache up in Horn River in B.C. This plant uses saline water from an aquifer deep underground. We treat it, and then we use that water in our hydraulic fracturing operations up in Two Island Lake. We're to the point where about 98, 99 per cent of our hydraulic fracturing is with saline water as opposed to fresh. Industry is continuing to look for new water sources in all of our operations wherever we can.

There's also a lot of ongoing research into hydraulic fracturing. This is an example of one study that came out in 2011 that said that shale gas was significantly worse than coal in terms of GHG emissions. The follow-up consensus, which was proven by four different studies, is that shale gas emissions are actually 40 per cent lower than coal. Part of what industry is doing and what we really want to get out there is that there are a lot of studies being done, and we want to make sure the right information is getting out there to the public. So we continue to help to do that.

Another example of this is with drinking water contamination. There's a lot of concern that hydraulic fracturing is going to contaminate drinking water, but to date there haven't been any studies that have proven that drinking water has been contaminated with hydraulic fracturing. In fact, there have been some studies that have disproven it, which are listed on that slide.

Like I said, we continue to want to get that message out there and are working to help to broadcast those studies where we can.

Mr. Foreman: I'll take it over and talk a little bit about the markets and, I guess, with all the natural gas potential that we have here in Alberta, how that's going to be impacted. This is a bit of a slide looking at North America, and you can see TCPL, the TransCanada pipeline. You know, over the last five, six years the amount of gas going through that pipeline from western Canada over into kind of the Boston, New York areas has decreased by 50 per cent. That's not because the demand has necessarily decreased. It's because the technology of hydraulic fracturing has unlocked resources that they have in that area. If you've heard of the Marcellus shale, that's really a very thick and very pervasive shale that extends over that entire market, which is the biggest market in North America for natural gas. Now they really have their own supply.

There are a lot of issues there, concerns, et cetera, around hydraulic fracturing, but as they're working through those and proper regulations are being put in place and the Department of Energy in the States is working to make sure that things are done properly, they are bringing more and more gas on, and all that gas is offsetting western Canada. The message there is that, you know, they are and will be supplying their own natural gas in that New York area.

6:35

You know, as that happens, our market is decreasing. It's disappearing. The future that we see is LNG. Without LNG – I mean, in our central hub here in Edmonton, AECO, day by day the price is staying flat, and the amount of gas that's coming here is decreasing. It's just a reality. We need new markets, and LNG is going to be part of that.

You can see here along those same lines – let's talk about Asia for a second – that there's kind of the natural gas energy demand that's occurring in Asia. You can see just how much they're planning to ramp up. I guess India is included as well right here. You can see that China is the big player here, and they've just got huge natural gas demands. You know, they're looking to western Canada and to the entire world for this, but you can see by a lot of the joint ventures that have occurred with companies in western Canada such as ourselves that there's a huge need, and they see western Canada as part of the solution.

You can see in this slide here – I talked about it a couple of slides ago – about western Canadian natural gas. It is decreasing, and it will continue to decrease over the next 10 years, et cetera, until, hopefully, LNG comes through. You know, Alberta and B.C. are going to be a big part of that, but it's really LNG that's going to be holding the demand up. It's not going to be North American demand anymore; it's going to be Asian demand for our natural gas that's going to help keep this industry alive.

You can see here, you know, the major plays that have natural gas in B.C. and Alberta. You can see that the biggest ones right now that are economic are the Montney, that kind of straddles the border of B.C. and Alberta – they both have very big positions – but it's the Deep Basin and the Duvernay that also have a ton of potential. Really, the Duvernay, that you see there kind of hidden behind that red blob, has got a vast amount of resources, perhaps almost as much as half of the oil sands combined. It's very huge. Not to get too technical, but what we call the Duvernay is a source rock, so the hydrocarbons that are being produced from organic matter over time: a lot of them in Alberta are coming from the Duvernay. All of these conventional resources we've been chasing: well, it's hydrocarbons that came from the Duvernay and have migrated over time to fill up these other reservoirs. So the Duvernay is a huge potential. It's a source rock. It's got tons of liquids, lots of natural gas, and if we unlock this resource over the next five to six years, it has a huge potential to be a big supplier for natural gas and LNG.

As well, there is a ton of liquids in the Duvernay which are going to be important for the petrochemical industry. Not only that, but there's a lot of condensate in the Duvernay, and that's going to be a huge supplier for the oil sands. The demand for condensate in Alberta is huge. There are pipelines that are getting reversed to bring condensate into Alberta, so if we can get the Duvernay going, not only can it supply LNG with natural gas; it can supply the petrochemical industries with ethane and the oil sands guys with condensate. So it's got the capability of doing a lot, but we're not at the commercial phase yet. We're far from it, and we need to strategize together as a province, really, to make sure that we can get this thing to a commercial phase in time for LNG, et cetera.

I won't talk too much to this point. I guess we've talked about the Duvernay quite a bit already. You know, it's a huge liquids-rich play, and there's really a huge potential for LNG. It's been recognized by lots of Asian companies already. Our company has a joint venture with PetroChina. They want to be part of the full value chain of getting natural gas to China and to Asia. They've invested with us in very large amounts. They plan to invest up to a billion dollars a year for the next 20 years into this play given that we can make it commercial. So there are huge investments coming from China given that we can get this thing to a commercial phase and get it supplying natural gas for LNG.

I guess I've talked to a lot of these points. In our dealings with PetroChina – and a lot of these other Asian companies have been interested in western Canada – one of the big drivers for them is understanding that there's going to be a good regulatory system and a stable royalty regime. Those are two very big things that rang loud and clear with them, you know, that we have an environment where the government is for the most part very stable. They do support development and don't want development to just dry up and disappear. It's not a situation where the doors are going to get closed or anything. People rely on this industry in Alberta and its jobs, and there's going to be huge potential here. Those things ring very true for them, that we've got an environment that supports, I guess, our industry in the right way. Doing things responsibly, obviously, but hydrocarbon capture is encouraged here.

One of the pieces that I'll just talk about a little bit here is something that's very important to getting access to these resources: understanding all the other stakeholders that will be affected by the development. Caribou is one of those things that we're looking at very closely right now. Right in the heart of the best lands in the Duvernay there's a caribou range. Little Smoky and A La Peche caribou herds kind of overlap our development with the better lands in the Duvernay right now. It's a government-led program right now, but it's a multistakeholder process that's really looking – you know, we have NGOs, First Nations, the government, and industry all sitting at the table talking about how we can do development here and still maintain these herds. How do we have to do that? Do we have to take lands out of the picture for a little while or rotate development around it?

It's going to be another year or two before all of this gets resolved, but these are the things that have to be addressed early on. There's a lot of potential in the Duvernay and the Deep Basin and the Montney, but all of these things are going to be very important in getting development to that commercial phase, you know, where we're not negatively impacting things like caribou.

This is another piece. I've only got a couple more slides here, so I'll try and get through them pretty quick. Really, a big piece for our industry is working towards regulations that are focused on unconventional resources. When I say that, a lot of the regulations in the past have been very based on vertical drilling and conventional reservoirs. As we're moving to these vast unconventional plays, we're in a situation where a lot of the regulations aren't fit for purpose. By no means are they regulations that shouldn't be there or were developed wrong; they're just not fit for purpose.

You get into things just because of the shape of the well, et cetera, things like spacing and how many wells you can have. This type of development wasn't thought out, you know, 20 years ago when some of the regs were put in place, so there's a huge opportunity to mould and shape the regs now that fit, I guess, where development is going. Not necessarily to open the doors and cut red tape or anything. That's not the goal. It's really to make these regulations fit the type of development that it's moving towards.

I guess one example of that – I won't get into too many – would be on the water side, approvals for water. When we're looking at the amount of water we need, yes, it is large volume, but the way we're developing things now is that instead of doing lots of vertical wells, we're doing a few horizontal wells. So on a per-well basis the water volumes, et cetera, are much larger. But when you look at how much water we're using to capture that resource, it's no different than what we were doing in the past. We're just doing our completions and our hydraulic fracturing and our drilling differently. So it's important to make sure that the regs, that have been approvals we got in the past, fit for this horizontal world where we're doing multistage fracturing.

Here's just a brief snapshot looking at the Duvernay. These are some economics. I know this is kind of private to EnCana, but it's important to share. People understand, I know, that the Duvernay is a huge resource and that it's going to be there for a long time. But we're still at the pilot stage. We're not at a spot right now where it's commercial. Where we see it becoming commercial is, you know, five, six years from now when LNG is kind of hitting. So the timing with LNG works perfectly.

I have this graph up here, and each of those bars is three different colours. I just wanted to highlight the green bars and the grey bars. Those are royalty programs that are in place that apply to the Duvernay. You can see just how large those programs are for the Duvernay and how much of an economic impact they make. I have a rate of return on the left-hand side here, and you can see that half the rate of return we're getting out of these Duvernay wells is coming from the royalty program that this Duvernay fits into.

Without these programs this play may not exist. It may not go forward. These programs, you know, are very important for plays like the Duvernay. The good thing about them is the way they're written right now. They're very targeted, so what you're seeing here doesn't apply to the Montney; it doesn't apply to the Deep Basin. I think the government has done a very good job in looking at these plays, looking at the stage of development they're in, and putting programs in place that encourage this activity.

6:45

This is something that is very necessary and very required at the early stage of these plays, having that certainty going forward that we're going to have something in place that's going to encourage development. Without that, none of these wells get drilled, period, and there are going to be no royalties coming from the Duvernay.

I guess that's kind of the last slide. In summary, like I mentioned, there's a huge amount of unconventional resources here. Alberta hasn't tapped into them maybe as much as B.C., but it's there, and we're going to need a lot of help, I guess, on the royalty side and the regulatory side, making sure that what's in place fits. So that's kind of the message in terms of a strategy for helping out.

The Chair: Thank you very much. I assume that you took out the numbers on the rate-of-return column because it's proprietary.

Mr. Foreman: Yeah.

The Chair: Okay. It's so tempting to know what that is.

Ms L. Johnson: That would put you in a conflict of interest, Donna.

The Chair: Yeah.

Mr. Sendall and Mr. Walter, we'll hear from you, and then we'll have questions. Lots of people will be asking questions, and they may direct them, but in lots of cases it's to everybody because you have different perspectives.

In Situ Oil Sands Alliance

Mr. Sendall: Okay. Thank you for the opportunity to speak to the committee today. I'm here on behalf of the In Situ Oil Sands Alliance, of which MEG Energy is a member. We'll be coming at this topic, monetization of the value of natural gas, from a slightly different perspective. As oil sands producers we're consumers of natural gas but producers of oil sands and also power generation to the province of Alberta. We're going to go through a presentation that each of you should have in front of you, and we've also provided a copy of an energy policy paper that was written by the University of Calgary, which takes a detailed look at cogeneration benefits within Alberta.

The In Situ Oil Sands Alliance is the voice of a group of vibrant and forward-thinking oil sands companies. Our goal is to manage the responsible development of an industry that we can all be proud of. In Situ members are all independent, Alberta-based companies. Our members manage a combined 44 billion barrels of resource base. We use creativity and expertise to advance technology in the oil sands. This kind of innovation reduces our environmental impact, improves our efficiency, and lowers our costs. IOSA members include Athabasca Oil Corporation, Connacher Oil and Gas Ltd., Laricina Energy Ltd., MEG Energy Corp., and Osum Oil Sands Corporation.

We'll now begin with some context regarding Alberta's oil sands reserves. Canada has 173 billion barrels of oil reserves. It's the third-largest resource base in the world, behind Venezuela and Saudi Arabia. A hundred and sixty-eight billion barrels of this is located in Alberta's oil sands.

Of this oil sands resource, approximately 80 per cent will be recovered using in situ production techniques. These are resources that are too deep to be mined, generally deeper than 70 metres. Advanced technology is used to drill down into the resource to heat up the bitumen so it can be pumped to the surface. There is minimal land disturbance, and it does not produce tailings ponds. In situ oil sands development can be thought of as drillable oil sands.

There are a variety of methods used to access Alberta's deep underground resources, including cycle-steam stimulation and solvent injection; however, the most common recovery technology is steam-assisted gravity drainage, or SAGD. To start the SAGD process, horizontal wells are drilled into the reservoir and the resource deep below the surface. We also employ pad drilling to access the resource base. Steam is injected into the top well, also known as the steam injection well. The steam heats the bitumen, reducing its viscosity, allowing it to flow to the lower well, where the oil and the condensed water from the steam are pumped to the surface and then sent to the processing facility by pipeline.

At these facilities the oil is separated from the water, the oil is sold by pipeline, and the water is recycled back to the steam generators. In fact, 90 per cent of the water used for steam comes from recycled produced water. Any makeup water needed is secured from deep underground, nondrinkable water sources. Any reject water from the system is disposed back to these deep underground zones.

Steam generation is critical to the process. To generate the steam, we use natural gas. The steam required for SAGD presents Alberta with a unique opportunity to cogenerate both steam for the oil extraction and electricity at the same facility. The primary technology for steam generation in the oil sands is the once-through steam generator, also referred to as OTSGs. OTSGs are very large, specialized boilers for SAGD steam generation which utilize natural gas as the heating source, much like your traditional home hot water tank, but they are optimized to use recycled, nonpotable water.

The addition of cogeneration to the in situ process can provide significant advantages. We use clean-burning natural gas to generate two energy products, electrical power to supply site power needs, with any additional power generated exported to the Alberta grid, and steam from the cogeneration unit, used on-site for bitumen recovery.

As demonstrated on this slide, MEG Energy elected to install one 85 megawatt cogeneration unit in addition to four OTSGs to meet its total steam demand. The single cogeneration unit produces approximately the same amount of steam as the other four OTSGs, and it also provides the additional benefit of electricity generation. A 50-50 split of OTSGs and cogen steam production is viewed by MEG as an optimal design.

This schematic provides a more detailed explanation of the cogeneration process. By implementing cogeneration, we produce two products, steam and power, from one energy source, natural gas. Natural gas is used in the gas turbine to create electricity while the hot exhaust is captured in a heat-recovery steam generator and used to generate steam. The result is the efficient generation of steam for the oil production and power for site operations as well as Alberta grid supply. This reuse of hot exhaust is a key to the efficiency improvements gained in the cogeneration process.

Since SAGD operations can use the steam from cogeneration, it is also most efficient in the use of energy contained in the gas for steam generation, while also providing the lowest possible electrical greenhouse gas intensity of any other fossil fuel generated power.

There are three key benefits to cogeneration. It's reliable. Natural gas turbines are proven and reliable. As SAGD is a full-time, 24/7, 365-days-of-the-year operation, it results in the production of baseload steam. With cogeneration, baseload steam equals baseload electrical power to the Alberta grid. Cogeneration also offers low-cost power to Alberta's grid. Because SAGD requires continuous steam for its operation, the exported electricity is not price dependent and is usually bid at zero megawatts into the Alberta power pool. This has the effect of averaging down the power pool price, to the benefit of all Albertans. Cogen power is also green. As mentioned earlier, the effective use of natural gas to generate two products results in the lowest greenhouse gas electrical intensity possible using a fossil fuel.

6:55

So how does this all play out on the oil production side of the equation? Life cycle assessment is a process to assess the environmental impacts associated with all stages of a product's life cycle, from extraction to transportation to its final, ultimate utilization. You may be aware of pending low-carbon fuel standards regulations in the European Union and California. Both of these systems rely on life cycle analysis as a basis for developing that regulation.

This graph shows the life cycle emissions on a wells-to-wheels basis for common oil imports into the United States, Alberta's most important export market for oil. It is based on research conducted by Jacobs Consultancy for the Alberta Energy Research Institute. You'll notice a range of 96 to 114 grams of carbon dioxide equivalent per megajoule of energy consumed.

The SAGD production assessment is depicted on the right-hand side of this graph and labelled as in situ unconventional. SAGD production with a steam-oil ratio of three, which was used in the study by Jacobs as representative of SAGD production, has a comparable life cycle emission value to most common U.S. imports. The steam-oil ratio is a measure of thermal efficiency, how much steam is required to produce a barrel of bitumen. When you add cogeneration benefits and an improved steam-oil ratio of 2.4 – an example of a MEG Energy-produced barrel – this number falls well below the common U.S. oil imports. Cogeneration is therefore a critical technology to help reduce greenhouse gas emissions for the oil sands production and secure our industry's social licence to operate.

Cogen can also play a significant role in meeting Alberta's future power demands. The image on this slide shows AESO's 2012 long-term outlook for power demand in Alberta. AESO forecasts that power demand in Alberta will increase significantly through 2032. Additionally, Alberta will need to replace significant baseload coal-fired electricity as federal greenhouse gas regulations force retirement starting in 2019. This creates a gap between demand and supply within which cogen can play a significant role. CAPP's production forecast predicts 2.3 million barrels per day of in situ growth by 2030. Our estimates, based on these in situ operations deriving half of their steam from cogeneration, indicate the potential to produce approximately 4,800 megawatts of cogen capacity in this time period.

For reference, Alberta's current maximum generating capacity is approximately 13,000 megawatts, while the daily net generation is closer to 11,000 megawatts. Because cogeneration can displace baseload power generation, it results in significant greenhouse gas emission reductions, potentially 26 megatonnes by 2030. Now, to put this in perspective, keep in mind that Alberta's 2008 climate change strategy target called for a reduction of 37 megawatts of greenhouse gas emissions through green energy production by 2050. Cogen could be a significant component of that. So by deploying a cogen strategy in the oil sands, it can assist Alberta to gain its social licence to operate. It's an opportunity that is unique to Alberta.

We have noted a number of benefits of cogen. However, one that is of particular interest to this committee, as it explains ways to encourage the broader and higher value use of natural gas, is the potential to increase natural gas use. Using the CAPP forecast for in situ production growth, if all new in situ facilities derive half of their steam from cogeneration, gas use in the in situ oil sands could grow by an additional 3.7 bcf per day. That's 1.3 trillion cubic feet per year by 2030. This represents an approximate 25 per cent increase from current Alberta production, which is about 15 bcf per day. This will increase royalty revenue through the additional use of natural gas, and it helps to stabilize natural gas price and royalty generation from all gas production throughout the province.

Now, cogeneration installation at an in situ facility is a business choice. Current adoption of this technology is low, with approximately 1,200 megawatts of installed capacity. Some operators have elected to install small cogeneration units that are sized only for the on-site electrical demand; that is, they size for the power requirement rather than sizing it for the steam load. A significant opportunity exists as in situ production increases. We feel that low adoption is due in part to low recognition of the benefits of cogeneration within the provincial greenhouse gas regulations.

So how do we maximize this opportunity? IOSA members believe there is one environmental policy lever that could be adjusted to encourage greater adoption of cogeneration. Alberta was the first jurisdiction in North America to regulate greenhouse gas emissions in 2007 through the specified gas emitters regulation, commonly known as SGER. SGER requires all facilities that emit more than 100,000 tonnes of greenhouse gas emissions per year to reduce their emissions intensity by 12 per cent. Within the regulation SGER compares cogeneration operating intensities to one that approximates natural gas combined cycle electricity generation; hence, recognizing only approximately one-third of its true benefits.

To maximize cogeneration use in in situ oil sands, we believe that full recognition of the environmental benefit should occur. This would be accomplished by using the greenhouse gas value that the power displaces on the Alberta grid instead of a hypothetical value based on natural gas combined cycle electricity generation. This policy adjustment would level the playing field, establishing a carbon as carbon price and policy, it would improve the transparency and credibility of Alberta's regulatory system, and it would position the industry to be compliant with pending low-carbon fuel standard regulations in other jurisdictions. In short, it would encourage cogeneration increase in the province.

7:05

So how does all of this come together? Let me summarize my remarks from today. The growth of cogeneration associated with in situ production is a benefit for and is unique to Alberta. It materially increases gas demand up to 1.35 trillion cubic feet per year if all future in situ growth includes cogeneration. This increases royalty revenue to the province through additional gas demand. It helps stabilize the gas price, increasing the royalty revenue to the province on all gas produced.

The potential is there to generate 4,800 megawatts of green power, improving the environmental performance of Alberta's power generation fleet and putting Alberta well on its way to meeting its own greenhouse gas reduction targets. The electricity produced is reliable, baseload power produced at low cost to Albertans, helping to meet the province's growing needs for electricity and the replacement of retiring coal plants.

Finally, cogeneration helps to secure the social licence to operate by lowering the life cycle greenhouse gas emissions of Alberta's oil sands, all at no cost to government by simply recognizing the true benefit of cogen within the province's greenhouse gas regulation.

I want to thank you very much for your attention, and I look forward to taking your questions. I also want to mention that MEG Energy would be very happy to offer a site tour of our Christina Lake facilities for any committee members that are interested in doing so. Come see it for yourself.

The Chair: Thank you very much. We actually do field trips. They're very helpful. We've got one planned for December. Is that something you would extend, and whoever could go would just set it up?

Mr. Sendall: Yes. We would welcome that opportunity.

The Chair: Okay. Maybe if you could just send me or the clerk a note to that effect, we will make sure that it's logistically organized.

Mr. Sendall: Great. We will do that.

The Chair: Wow. There's a lot there. We create speakers lists, so I'm open to whoever wants to be on that list. Joe was asking questions even before you finished here, so we'll let Mr. Anglin start. Then if you've got a question, just put your hand up or get my attention. The two fellows on the phone: I'll call for questions at the conclusion of Mr. Anglin's questions, okay?

Mr. Anglin: Thank you. If you could just back up to slide 13, I would like you to elaborate, please, if you would, particularly on the bulleted paragraph where you're talking about recognizing the true environmental benefit and, in particular, talking about the value of power being displaced on the grid because I think that's significant. So if you wouldn't mind, could you elaborate more on what we're displacing here in this hypothetical value for combined cycle electricity? And if you want to use examples of the hypothetical, that would help also.

Mr. Sendall: Thank you. Alberta's average intensity of power on the grid currently has a value of .88 tonnes of carbon emissions per megawatt of power on the grid. Cogeneration produces power that's approximately a third of that value. So any power generated through cogeneration in an in situ setting does displace higher intensity power off the grid. The current regulation recognizes only a portion of that full benefit of the power you're displacing from the grid in that it acknowledges and gives you recognition versus natural gas combined cycle generation of that power. So what we're proposing here is that full recognition of the power displaced on the grid will encourage the further adoption of cogeneration in in situ oil sands.

Mr. Anglin: Would power purchase agreements be something that would also, in your view, help to promote this cogeneration? Is that something the industry has considered?

Mr. Sendall: Yeah. Power purchase agreements. Currently we do produce our power, and because we rely on the steam for the in situ generation of the oil, we operate 24/7, 365 days of the year. In order to get that power exported out onto the grid to keep our cogeneration operating, we bid into the system, into the pool price, at a very low price.

Mr. Anglin: I understand that. A lot of times you offer in for zero, and I picked that up. According to the AESO there's as much as 6,000 megawatts at any given time that can be offered in at zero.

What I'm really interested in to advance this type of technology is power purchase agreements for you to sell your electricity to industry. We have currently a few of those in the province, and it is something that is of debate, whether or not we should continue with those power purchase agreements. Most of our power purchase agreements are from the coal plants, coal generation. I'm just wondering: is that something that would help this industry expand?

Mr. Sendall: We are in favour of moving away from power purchase agreements. The system as it is now, yeah, we bid into the pool price.

Mr. Anglin: I assume that was a no, then.

The Chair: Okay. We'll bring this back to gas. You just love power purchase agreements, but we'll stop there.

Who else has a question?

Mr. Barnes: If I could, please, I'd like to ask both groups. I've been an MLA for about a year and half, and many, many times in the House I've heard the words "social licence," what it means for Alberta to earn this social licence. I'm very curious from both of your standpoints what it means to you and your companies to earn this social licence.

I represent Cypress-Medicine Hat, and my second question might be more for EnCana. We're maybe hit the hardest with the loss in the value of natural gas in terms of, you know, the work that used to be provided extricating this asset. We do, however, have a couple of firms – Methanex and Canadian Fertilizers come to mind – that are doing tremendously well because of the low price of natural gas. I'm curious as to what you think the opportunities in Alberta may be for other industries like that to flourish with our long-term, cheap natural gas.

Thank you.

Mr. Foreman: I heard two questions. Do you want to answer the first?

Ms Koskie: Sure. In terms of social licence what we're talking about is really making sure that the stakeholders and the people who live in the areas where we're operating understand what we're doing, are comfortable with the development happening in their area. We just really want to make sure that we have a dialogue with them so that if they are uncomfortable with something, they know someone in their community or a surrounding community that they can contact and discuss those issues with. That's one part of it.

Then the other part is really just educating the general public. In the digital world that we live in, information spreads so quickly. It's not all correct or factual information, so we want to make sure that the scientific information is getting out there and people really understand the industry and what's happening around them.

Mr. Sendall: Yeah. I can add to that. From our perspective we look at social licence from a broader base, in that there's a large faction there that simply wants to wean the world off of fossil fuels. Although that's an admirable goal for greenhouse gas emission targets, basically we want to get factual information out into the public so they understand the product and are educated on energy use in our society and the value of that to our society.

7:15

Ultimately, where this translates is gaining market access. Pipeline connections to our major market suppliers in the U.S. or getting oil out on the water off the west coast or east coast would not be the issues they are today if we had that social licence. So it's getting our reputation and the value of this industry, the need, and, really, the quality of life that comes from energy production and use and bringing that home to each individual constituent so that we are offered that appropriate ability to grow our business and access our markets.

Mr. Foreman: Okay. I guess the second piece I heard was: in the communities how can you take advantage of lower natural gas prices? In a way, I think it would be on a community-by-community basis. Other than, you know, Methanex, like you mentioned, fertilizer, there are small LNG plants. You can look at the transportation side as well, and I think there are opportunities there. They're all somewhat small pieces of the pie, and I think that on a smaller community basis there are going to be opportunities in and around the province, for sure, if there are corporations that want to be part of taking advantage.

I think the bigger win for Alberta per se might be in looking at the petrochemical side and cheap ethane prices that are going along with cheap natural gas prices. They're tracking exactly the same as each other, so for Alberta to win, I think it maybe needs to be looking more at the ethane price with petrochemical.

On the community side – you know, Methanex, fertilizers, small LNG plants – not for export but for use within communities there are opportunities there for sure. There's power generation that's done with diesel engines, et cetera, that could be converted over to natural gas, et cetera, in communities. I think there are opportunities there.

We're going to have low natural gas prices for a very long time. You know, we're looking at LNG, and it could bring things up to – let's call it \$5. We used to be at \$11, \$12 for natural gas. We're looking long term at trying to make these things economic at \$5. If there are opportunities out there for other companies or if there's dialogue going on, they can be pretty confident that natural gas prices are staying low for a very, very long time.

You know, we've got a group in our company called natural gas economy. They're looking at and pushing as many things as they can to drive demand for natural gas on those types of things. Transportation is a big one of them, converting buses over to natural gas, et cetera. I think there are opportunities, but it's very, very slow moving on that side of things. We've been pushing it for five years, and it's very slow moving trying to get things engaged.

The Chair: All right. I've got Dr. Swann and then Ms Fenske.

Mr. Lemke or Mr. Sandhu, do you want to be on the list? Okay.

Dr. Swann: Thanks very much for your presentation. I think factual information is critical. I think that for your credibility you also need to acknowledge that the EPA has identified groundwater impacts from fracking in the east U.S. That would be helpful.

The other thing, I guess, to say about some of the important work that's done by chem labs across the province is that they have identified a large proportion of older wells, presumably, that are leaking. We are emitting from older oil and gas resources significant amounts of methane, and we have to do better. I think we are doing better now with more recent drilling, but when they talk about a third of the wells they visit having some degree of leakage, I have concerns about whether we're meeting our social responsibility to the work that we're doing.

I guess I wanted to ask a question about the base of groundwater protection and the baseline groundwater testing that you alluded to in your remarks and where that's being done and what's happening to the results. My understanding is that the study that began in 2006 by the Alberta government has collected thousands of samples of baseline gas in water, and it's never been reported. So we don't actually know what's been happening to our groundwater over the last six years. If this was the only study – and I'm only aware of one study, that was begun in 2006 – then we don't really know what's happening to our groundwater at this stage. I would ask you to comment on that and ask you to encourage this government to get on with that study so that we can all know where it's been impacted and where it hasn't and have some confidence in talking to communities who are suspicious that this government is burying information.

I've provoked a lot of issues there, but feel free to comment on any of them.

The Chair: Yes. That's a technical question and a political question, so we're inviting them to be politicians as well.

Dr. Swann: It's all scientific. It's all based on good science.

Mr. Foreman: Sure. I think as a company that operates – by and large in the past we were one of the leaders in bringing CBM to the market, which is why that study kind of took off in 2006. Really, I wouldn't necessarily call it just a study. It was regulation that changed so that we had to do groundwater testing within a 600-metre radius. We've been doing that on every single shallow well that we drill in CBM. I'm assuming what you're referring to is more on the CBM side, the shallow drilling in central Alberta.

Dr. Swann: You indicated that you do baseline groundwater testing, so I'm asking you where you do it, then.

Mr. Foreman: Okay. We do it in all of our fields. It's regulated in central Alberta for CBM and shallow fracturing. There it's regulated to 600 metres. Our commitment through the hydraulic fracturing practices is looking at 250 metres away from our well bores to do baseline groundwater testing on any existing water wells that are there.

Dr. Swann: Regardless of the depth that you're drilling?

Mr. Foreman: Yeah, regardless of the depth. In our shale, in unconventional resources, yes.

Dr. Swann: Okay. Thanks. That's good to know. Thank you.

Mr. Foreman: So there is that commitment from CAPP, and all the producers should be signed off on that.

Dr. Swann: It's not regulation, but it's recommended.

Mr. Foreman: It's not regulation, but it's something that CAPP expects of its members.

In terms of going back to the study that was started in 2006, we've spent tens and tens of millions of dollars on doing all of this testing. All of that data is reported on and housed with the government. Has there been a lack of a report that's come out? I would completely agree. From our knowledge there have been zero instances of contamination of the groundwater. There is methane that is in groundwater naturally. All of our results – and I've been privy to everything. When you look at the gas, it's comparing biogenic and thermogenic. Not to get too technical, but we haven't seen any instances where, looking at fingerprinting analysis of the gas, there's been any bit of contamination or migration up. It's naturally occurring gas that we're seeing and not in every well, and it was there before we came.

Is there some methane? There is some methane. Are we seeing because of fracturing more methane? We haven't, and we haven't seen any study that's actually said that. I know that the ERCB, I guess before they became the AER, or the regulator, had done a lot of work with Alberta Environment. This was probably in 2009. They did a study there, and there was a report that came out. But I think maybe your expectation is for maybe a larger study on all this data that's come in. I know that about seven or eight months ago all that data became public. They finally got a database. If you go on the Alberta Environment website, there is a link to a database. You can access that.

Have they put a study out? No.

Dr. Swann: And what are we supposed to do with all that data as lay people?

Mr. Foreman: Well, what they've done – and I'm actually going to give you a name here so you can call him, too, because I make phone calls all the time. Steve Wallace at Alberta Environment is probably somebody that could answer that question very well for you. There is an expert panel on groundwater that was put together, and he partially led that. I haven't seen a report come out of that, and we've been calling and asking for that as well. They kicked that off about a year ago through Alberta Environment, and I'm waiting to see the report. They're coming out with recommendations, apparently, with the report on what the results have been with all this testing that's been done and if there have been any instances. I don't know what's in the report. I'm waiting for it, too. But if you want to give that individual a call, they might be able to answer that better.

7:25

Dr. Swann: He's with Alberta Energy, did you say?

Mr. Foreman: Well, it was Alberta Environment. I guess it still is.

The Chair: Could I suggest that you may, Dr. Swann, want to ask our researchers to follow up and then get back to the committee with that?

Dr. Swann: Oh, sure. Good.

The Chair: Ms Fenske and then Mr. Casey.

Ms Fenske: Thank you very much. It's going to be a three-parter, so I'll just ask the question to EnCana, please. We had Ferus here as presenters not too long ago, and you're working with them to build an LNG plant out in the Grande Prairie area, so if you could comment on how much of that capacity is for EnCana's internal use and how much you're planning to sell to outside customers. Are you transitioning your large trucks and oil rigs to natural gas? If so, why? If not, why not?

Mr. Foreman: I don't know if I can specifically answer what percentage.

Ms Fenske: I just wondered: sort of two-thirds, one-third? If you've got anything . . .

Mr. Foreman: Honestly, this would be a guess, so I probably shouldn't even say numbers. I can get back to you on that.

In terms of our company and transitioning, we're looking at every single drilling rig we have. We're in such a manufacturing-style process that we have the ability to keep the same rigs moving to our wells, so we're looking at every single rig to convert over to natural gas, with diesel as a backup in a way. On our fleets we're looking at every single pickup truck to be running on natural gas, you know, within a number of years. Our service providers that do a lot of the work for us: we're pushing all of them to convert to natural gas as well. Are we there? No, but our goal is, one, for cost, but two, for a number of reasons we're looking at every single truck and rig we use to be using natural gas in the future as much as we can. Are we going to get there? No. There are a lot of companies that work for us that just won't have the ability. But where it's possible, we're pushing all of our service companies and drilling rigs and completions equipment to be running on natural gas, or LNG.

Ms Fenske: Thank you.

Mr. Casey: The slide that you had up on rate of return: just a question around not the specific stuff but, I guess, partly around the economics of it. I'm a little bit confused by the whole thing simply because we have vast resources. We know we have vast stores, but the more we extract, the lower the price goes. As around the world that occurs, we know the big consumers are going to be China, India, Pakistan, and so on and so forth, yet they're also out there with their own resources and their own natural gas close at hand. In the long-term vision of your company where do you see this going? The cost to bring all of this on is astronomical. Is the LNG export piece really the piece that is going to, in your mind, be the game changer here? To a layman it doesn't make any sense. We have all this reserve, and the more we pull out, the lower the price goes. It doesn't work to anyone's benefit except, of course, consumers. We're all loving that, but it doesn't do your company much good.

Mr. Foreman: I mean, go back five years, and the horizontal multistage fracturing is – you know, we sunk our own industry by unlocking all these resources, really, which is the truth. You can't refute that. We've unlocked a 1,500-year supply in B.C. They have a 1,500-year supply of natural gas. We in Alberta probably have a few hundred years' supply just for ourselves, so we've got more than we need, for sure, and that's what sunk the price. Definitely. The demand from the U.S. is down because they have their own supply now. LNG is it for us, to tell you the truth. We're not going to be able to operate – you can look at any natural gas company's financial statements; they can't continue to operate in this environment unless something changes.

There are two things that are going to happen. One, we're going to transition more towards liquids – ethane, propane, pentane, butane, and condensate – because there is still a market, a healthier market, in North America for those. Two, the natural gas has to go to LNG. Period. There's just no other option. If LNG doesn't occur and in big volumes that offset the prices and the markets in the U.S., natural gas companies in western Canada won't exist. Period. That's a reality. They're going to rely on LNG.

Mr. Casey: Just a really short follow-up.

The Chair: Go ahead. We have time.

Mr. Casey: So if LNG is the future, where do you see those markets expanding? If they're not currently there today, where do you see that new market?

Mr. Foreman: Where the LNG market is going to be overseas?

Mr. Casey: Yes.

Mr. Foreman: All of those companies that have been doing joint ventures with a lot of these players are doing it because of the LNG possibility. They're not doing it because they're investing in a natural gas company; they're trying to invest in the full-value chain so that when they're paying a higher price for the LNG hitting that market, they've been part of the entire process all the way along. They understand that there's going to be a higher demand for gas here because they do need that LNG.

Ms Koskie: Just to add to what Kellen was saying, we haven't had the ability to send any natural gas resources to Asia up to this point. The proposed LNG facilities in B.C., should any of them go ahead, will open up the markets and allow us to get the gas over there. So to this point the gas has really been stranded within

Canada and the U.S. because that's how we have the capacity to ship it. Now, if these companies are able to go ahead with the LNG plants, then we can get the gas out of North America and over to Asia. That's how the market would open up a little bit for us. The demand there is rising exponentially.

The Chair: Mr. Bikman.

Mr. Bikman: Thank you. Just an observation. I'd like to question, in particular, to verify if what I'm saying is correct. You really didn't shoot yourselves in the foot because the technology was going to be developed by somebody. You had to get onboard or you'd lose your share of the market, and if that was a way to produce gas cheaper, then you were obligated to your own shareholders to do it. It's not costing the Alberta government anything except for the fact that the world prices – and this is a global market – are down, so the value is lower. I think that's something that didn't seem to come through in Mr. Casey's question.

Also, because we are in a global market, you're looking at natural gas domestically in the mid-$3 range – correct? – and you just mentioned that you're talking about $5 LNG going to China. You've already got investors, again not the government, that are prepared to put up, in the case of Phoenix, a billion a year for 20 years, so that's going to produce more royalties for Alberta. Wasn't that part of your message?

Mr. Foreman: Absolutely.

Mr. Bikman: So I don't know what the concern seemed to be from that earlier comment.

If we don't get into that market, somebody will because the demand is there. We as legislators, the more that we can do to facilitate that and encourage neighbouring jurisdictions to go along with us so that we can get pipelines built, the better it's going to be for all Albertans. Correct or not?

Mr. Foreman: Absolutely correct.

Mr. Bikman: I heard you correctly?

Mr. Foreman: Yeah.

Mr. Bikman: I heard previous presenters correctly? That seems to be the message, that we've got to get that market.

Mr. Foreman: Absolutely. North America probably has a bigger resource of natural gas that's in these shale and unconventional reservoirs, much larger than you're seeing all around the world. What we have here has sunk our natural gas market. You look at Europe and you look at Asia, and they still have very high prices.

Mr. Bikman: So if we don't step in to meet that demand – we can't sit back and think that we're working in a vacuum here. The Americans are certainly trying to get all of that to market.

Mr. Foreman: Yeah. We have a natural advantage as well. They have to go around through the Gulf. We have a natural advantage of where our resources are to the ocean. Honestly, it's going to be a race to the market, and if people start setting up these plants in other places, contracts are going to fall into place, and we're going to lose our spot in the world race.

7:35

Mr. Bikman: So as legislators representing Albertans we're going to be shooting ourselves in the foot if we don't do all that we can to encourage this development in a socially acceptable way.

Mr. Foreman: I completely agree.

Mr. Sendall: If I may add to that, I also want to make sure that we don't lose sight of the fact that we as Albertans have a unique and natural advantage in the oil sands resource that is here, a growing supply, a growing energy demand through that for natural gas growth right here in the basin. It's all connected by pipe now. Transportation cost from source to end demand is all connected and inexpensive within this basin as opposed to expensive transportation options to take it offshore.

Mr. Bikman: A lot of the infrastructure is already in place, right?

Mr. Sendall: Exactly.

Mr. Bikman: You've got a trained workforce, and you've got a jurisdiction that's governed by rule of law as opposed to some other areas of the world that aren't. We have lots going for us.

The Chair: Okay. On my list I've got Mr. Webber, Mr. Barnes, Mr. Anglin, and Dr. Swann. I've got some questions, too. I'll just throw myself on the list.

Mr. Webber: All right. Madam Chair, thank you. This will be quick.

The Chair: We've got time.

Mr. Webber: It's a question that I'm going to direct to our IOSA friends here. It's a question that you would likely get from a grade 2 class, and I'm a little embarrassed asking it, especially on *Hansard*, but I'm going to anyway. It's in regard to the recovery of the oil sands and the oil. You indicated that 80 per cent of the reserves are done through in situ. Why can you not use the in situ technology in order to get at the shallower reserves rather than having to mine? The technology, obviously, is not there. Can you just maybe talk a little bit about that?

Mr. Sendall: I think fundamentally what is needed to extract the resource using technology like SAGD, where you're injecting steam into the resource, is a thick, highly permeable resource with the absence of impediments to that steam being able to percolate up through that resource to heat the oil and allow it to flow to the lower well. Also, you need a caprock containment on that resource, and as you get shallower in the Earth's crust, often that caprock is nonexistent.

Mr. Webber: Okay. That's the reason. All right. I'm embarrassed for asking it. Thank you.

Mr. Sendall: That's fine.

The Chair: Thank you for your honesty.
Mr. Barnes.

Mr. Barnes: Thank you, Madam Chair. I have a question for each of the groups, please. First, to the EnCana group, I think we heard from an earlier presenter that there was quite a bit of supply risk, that in Asia they made a start to discover their own natural gas, and we may get in a race to get over there and discover that the market starts to get met over there by themselves in five or 10 years. In light of what Gary Bikman was just saying with our current infrastructure, can we do this without any royalty changes or any changes in help from the Alberta government to get our liquefied natural gas here?

Mr. Foreman: I would say that from Alberta's perspective and from B.C.'s perspective – you guys have both done a very good job in terms of the royalty structure, in terms of setting up an environment that encourages natural gas development. I don't think those are necessarily the biggest drivers on getting it there. It's really pushing the development of the plants as opposed to the upstream.

We've got good programs in place. If we can maintain them and keep a steady environment there, it's going to feed LNG. We need some drivers that push the end LNG plants a little bit more. You know, there are a lot of things being talked about on the B.C. side, whether that's an excise tax, et cetera, and issues with the pipelines, and I think those are the things that are holding back LNG.

When it gets decided to go ahead, I think we're in a good position with our resources and with our regulatory and royalty structures already. If we can maintain those and keep those in place, I think we're in a good spot. It's really that we need something to be pushing the LNG plants a little harder. There are people that want to invest, but they want to make sure that, you know, the right structure is in place, and that still has to be thought through a little bit for building those plants, whether that's on the tax side, et cetera.

I think that's where more fear lies in getting this thing off. It's not the upstream, necessarily. We've got that resource. It's getting a plant built and what we can do to, you know, push that aspect of it.

Mr. Barnes: Okay. Does natural gas have a cost-recovery setup like the oil sands, where you pay fewer royalties until your costs are recovered?

Mr. Foreman: There's only one place in western Canada where that structure is in place, and it's in the Horn River. It's called net profit in B.C. It's only one little place, and only five companies are part of it. It doesn't sound like in B.C. they're going to expand that. No, there's not a cost-recovery piece per se where, you know: here are the actual costs, and we have cheap royalties until those costs are recovered. But those programs that are in place – there are programs to reduce royalties up front. They aren't tied to our capital cost necessarily like in the oil sands, like that program. Those are administratively tough programs, and I can't see anyone wanting to entertain that on the upstream side for natural gas.

Mr. Barnes: Okay. Then the part on China and India and Pakistan developing their own natural gas oil reserves: is there much likelihood of that happening in the near term?

Mr. Foreman: I'm probably not the best person to talk to on that, but I haven't heard maybe as much as you guys have just alluded to. I haven't heard that they've got the resources to meet their needs at all. I haven't heard that.

Mr. Barnes: Okay. Thank you.

To In Situ: is In Situ subject to the cost recovery before their royalties check in as well?

Mr. Sendall: The royalty scheme for in situ production and the oil sands in general is one in which we have a lower royalty rate until we reach a payout and then go into a postpayout royalty regime at a higher rate.

Mr. Barnes: Okay. Thank you. Does in situ generally recover quicker than the mining process? Can you talk about that, please?

Mr. Sendall: I don't have much experience on the mining side. The capital intensity of mining, coupled with upgrading, is normally higher. I think they're on par for a payout trigger, myself. But I don't specifically know the mining side.

Mr. Barnes: Okay. Thank you very much.

The Chair: I have Mr. Anglin, Dr. Swann, and then myself.

Mr. Anglin: Thank you, Madam Chair. I think Mr. Bikman covered most of what I wanted to ask, but I just wanted to be very quick with EnCana. If I understood you correctly, according to your business model there's a huge risk. You need to access this Asian market, and if you don't, your whole business model will be at risk. Is my interpretation correct?

Mr. Foreman: Natural gas is never going to dry up, but chasing natural gas only – we'll call them dry wells, where they don't have a lot of liquids associated with them. You're already seeing it in our company and in every other company. Like, in the Duvernay and the Montney we're chasing plays. There's a lot of natural gas there, but what's making them economic is the fact that they have condensate and liquids. There's still a market there. We're not drilling dry gas anymore. If you look in B.C. at our Horn River, if you look in central Alberta with our CBM, we're just not doing it anymore because there's no value right now.

Mr. Anglin: So your business model is really to get to that Asian market with liquid natural gas?

Mr. Foreman: Our business model right now is to stay alive with liquids.

Mr. Anglin: I think you answered it. I think I've got it.

Mr. Foreman: But there won't be a natural gas industry like there was or there is even today without LNG. It's going to slowly disappear, and we'll shift our business to more oil or liquids. We'll have to. So we need LNG.

The Chair: Dr. Swann.

Dr. Swann: Thank you, Madam Chair. I was impressed with your comment that you're using 98 per cent saline, or deep water, and only 1 or 2 per cent fresh water. That's very impressive.

Mr. Foreman: To be specific, that's in one area in B.C. where we've set up a plant, but it's a model that we're working to put into the bigger, larger plays.

Dr. Swann: Can you tell us about water use, then, in Alberta?

Mr. Foreman: Right now water use in Alberta is from fresh aquifers primarily. In all the plays, especially if you look at a play like the Montney or the Duvernay, they're large enough for a company like us that we can start setting up central facility hubs and start recycling water. Right now, if I had to throw a number out there, I'd say we use close to maybe 10 to 15 per cent recycled water in our operations, but it's primarily fresh water.

7:45

As we start to understand the resource, understand the future development plans, we're going to be setting these plants up. Already just across the border in B.C. we're setting up a plant in the Montney that's going to use saline sources and recycled water. So we're going to do the same thing we did in the Horn River in the Montney in B.C., and that's going to be ported. It's just a timing thing with the phase of development, but it's going to be in the Duvernay. We've already got plans to look at sources. It's just a matter of finding those saline sources.

There's going to be such a large demand for water that no company is going to be able to do it just off fresh. We need that certainty that we're going to have a water source, so saline, just from a commercial standpoint, is going to be a big part of the picture, and from our company's standpoint, you know, we're looking as hard as we can to find saline sources that we can access. It's expensive, but you need the certainty. We're moving towards it right now. We just have the one area. The other one is being built as we speak. It will be in Alberta, in our properties, you know, in five to six years, I would say.

Dr. Swann: Can you comment on the SAGD side of water use?

Mr. Sendall: Yes. For the SAGD operations in the southern Athabasca region, in which MEG operates, all commercial operations use nondrinkable and saline sources for their water needs. There's no potable water used in those commercial developments.

Dr. Swann: Why is that? Is it not quite a bit more expensive for you, I guess, to do that?

Mr. Sendall: It is a regulation within our approvals that does have us recycle 90 per cent of our water. Also, when we go through environmental impact assessments of our projects, we do assess the resource in the area, and that generally takes us to a non-potable, nondrinkable water source for our water needs.

Dr. Swann: Do you pay a price for surface water, for fresh water, either of you?

Mr. Sendall: We don't use it.

Dr. Swann: You don't use it at all?

Mr. Sendall: We don't use surface water in the process.

Dr. Swann: Potable water?

Mr. Sendall: Yeah. Potable water or surface water.

Dr. Swann: Is there a price for using it?

Mr. Foreman: Yes. I don't know exactly what it is.

Dr. Swann: It would be a lot cheaper than drilling down 5,000 feet for saline, though, wouldn't it?

Mr. Foreman: True. There is a small price. Generally, where we're getting our water from, yeah, there is a price. I want to say $96 a cube, but I think that's more of a full chain, what it's costing us, or something. There's a small price.

Dr. Swann: Thank you.

The Chair: I've got two questions, one for each of you. I find it really interesting. We're trying to look at the question of: how do we monetize Alberta's natural gas? Of course, it's a bigger conversation in Alberta. But one of you has your presentation geared to accessing LNG export, and the other presentation is kind of geared to how to value-add and utilize the resource here in-province. Perhaps the recommendation at the end of the day is some combination of all of those options, but if I could probe you both a little bit further in your company responses.

On the LNG side, we've heard from a lot of presenters. We heard from TransCanada last week, and most of the pipe that's being built – and you're familiar with that pipe because you've been attached to it before – is in B.C. It's an intra-B.C. pipeline, and it doesn't tie into Alberta. We're Alberta politicians, so we really care about Albertans realizing the value of Alberta's natural gas. I'm going to throw that question out to you, but I'll frame the other question for MEG.

You're talking about utilizing the gas in-province, and the comments about the direction to us to consider putting better value, clearer value on GHG are a really useful recommendation. I'm also wondering if you could advise us on: what do you need to see as a company with gas infrastructure to strip off liquids? You must be taking all the liquids off before you use that gas for cogeneration purposes, but then what are you doing with it? Our system – facilities and regulations environment for natural gas – inside this province: is it a block, or does it work? Those are my two questions.

I'll start with EnCana.

Mr. Foreman: In terms of how Alberta can work with B.C.: is that kind of your question?

The Chair: No. We kind of know how to do that. You're drilling for gas here in Alberta, and you're drilling for gas in British Columbia. From the Alberta side of that border, I guess, how do you plan on getting that gas into an LNG export market, or are you focused on B.C. gas?

Mr. Foreman: No, not at all. You know, B.C. has a large play in the Horn River and the Montney, but they're not going to be the full picture. I think that internally our fundamentals group, when they're looking at this, are looking at the price of AECO. There are pipelines that already exist big time between Alberta and B.C., and some of those will be changing direction. That's going to happen, and when that happens, the supply at AECO is going to go down, which will bring the price up.

You know, there are already existing pipelines. If B.C. is supplying a large portion of LNG, maybe there's less gas coming into Alberta from B.C., and maybe some of the plays will have access. I think that's all going to have to shake out looking down the line. From our company perspective, by no means is B.C. gas going to be the only supplier. You look at Horn River in B.C., and it's dry gas with lots of CO_2. It's so far from market that right now it's not a focus at all.

The Duvernay with liquids and the Montney in Alberta with liquids: there's value there, so that's what we want to ramp up our production on. We're going to find a way to get it into B.C. There are pipelines back and forth. We'll find a way. I'm really not concerned about that aspect. It's making sure that we do have a facility on the coast.

The Chair: Thank you.

Mr. Sendall: Yes. The question is: when we use our gas, what do we do with the liquids contained in that gas? Basically, as an in situ developer producing steam, we buy the purchased gas off the pipeline. It is a dry gas for dry gas and distribution specs. We buy it off the pipeline as dry gas. There are no liquids in it for us to extract from that. If the origin of the gas was a gas production well that also produced liquids, that would all be taken out very near to the production site before it actually enters into the sales gas pipeline that we purchase gas from. We do not do our own liquid separation of gas that we purchase.

The Chair: So the system works for what you're trying to achieve. That's what I'm taking away.

Mr. Sendall: Yes.

The Chair: Thank you.

All right. Well, we're at just before 8. I think we'll conclude with that if everybody has had their questions asked and answered.

Thank you very much to the four of you for coming and presenting. We know that you're not here and that you had to come into town, and we appreciate that very, very much.

If you've got comments that you want to offer up to this group after you get back to your offices and ponder our questions further or see something that we're talking about on this committee, please feel free to make that information available to us. We're very interested. Thank you.

We're going to spend about five minutes here finishing up some housekeeping stuff, but you certainly don't have to endure that.

Mr. Sendall: Thank you for the opportunity.

The Chair: We had a research request at our last meeting. Ms Fenske had asked for a map of where there might be potential for heavy-haul corridors in Alberta.

Ms Zhang, I think you were going to provide us some information on that.

Ms Zhang: Thank you, Madam Chair. Just a quick update. We contacted Alberta Transportation about that question, and they responded that they haven't given much consideration to heavy-haul routes in Alberta.

The Chair: Okay. Do we have any further research requests coming from today's meeting?

Dr. Swann: That one on the baseline groundwater report. Millions of dollars have been spent, and there's still nothing. Keith Wallace, is it?

The Chair: Steve.

Dr. Swann: Steve Wallace? Thanks.

7:55

The Chair: Yes, Dr. Massolin.

Dr. Massolin: Madam Chair, we will certainly endeavour to get that report. As well, I just want to report to the committee that there's one outstanding research request which is a bit of a tougher nut to crack, in terms of the microgeneration. We're still working on that, and we'll get back to the committee.

Thank you.

The Chair: Thank you.

Any other business?

Our next meeting is next Monday night, 6:15 to 7:15, and we're having Sasol present on their gas-to-liquids technology.

So thank you, and thank you again to Mr. Tyrell for putting this together. You do a good job. We appreciate it.

Mr. Anglin: Hugs all around.

The Chair: Okay. We won't go into *Kumbaya*.

Would somebody like to move a motion to adjourn? Mr. Bilous. All in favour? Any objections? Motion carried.

Good night, everyone.

[The committee adjourned at 7:56 p.m.]

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