# Yukon Legislative Assembly

Issue 1 33rd Legislature

## SELECT COMMITTEE REGARDING THE RISKS AND BENEFITS OF HYDRAULIC FRACTURING

**Public Proceedings: Evidence**

**Friday, January 31, 2014 — 8:30 a.m.**

Chair: Patti McLeod

# SELECT COMMITTEE
# REGARDING THE RISKS AND BENEFITS OF HYDRAULIC FRACTURING

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| **Chair:** | Patti McLeod |
| **Vice-Chair:** | Lois Moorcroft |
| **Members:** | Hon. Currie Dixon<br>Darius Elias<br>Sandy Silver<br>Jim Tredger |
| **Clerk of Committees:** | Allison Lloyd |
| **Witnesses:** | Gilles Wendling, Hydrogeologist<br>Paul Jeakins, Commissioner and CEO, B.C. Oil and Gas Commission<br>Kevin Parsonage, Supervisor, Field Engineering and Technical Investigations, B.C. Oil and Gas Commission<br>Adam Goehner, Senior Advisor, Environmental Engineer, Pembina Institute<br>H. Wayne Hamal, Chief Operating Officer, EFLA Energy, Inc.<br>Blaine Joseph, Operations Manager, EFLO Energy, Inc.<br>Richard Wyman, President, Northern Cross (Yukon) Limited<br>Don Stachiw, VP Exploration, Northern Cross (Yukon) Limited<br>Alex Ferguson, VP Policy and Environment, Canadian Association of Petroleum Producers<br>Aaron M. Miller, Manager, Northern Canada, Canadian Association of Petroleum Producers |

**EVIDENCE**
**Whitehorse, Yukon**
**Friday, January 31, 2014 — 8:30 a.m.**

**Chair:** Good morning. I will now call to order these proceedings of the Yukon Legislative Assembly's Select Committee Regarding the Risks and Benefits of Hydraulic Fracturing.

Allow me to introduce the members of the Committee. I am Patti McLeod, Chair of the Committee and member of the Legislative Assembly for Watson Lake. To my left is Lois Moorcroft, who is the Committee's Vice-Chair and Member for Copperbelt South. To Ms. Moorcroft's left is Sandy Silver, the Member for Klondike. Behind me is Darius Elias, the Member for Vuntut Gwitchin. To Mr. Elias' left is Jim Tredger, the Member for Mayo-Tatchun, and finally to Mr. Tredger's left is the Hon. Currie Dixon, the Member for Copperbelt North and Minister of Environment and Economic Development.

On May 6, 2013, the Yukon Legislative Assembly adopted Motion No. 433, thereby establishing the Select Committee Regarding the Risks and Benefits of Hydraulic Fracturing. The Committee's purpose or mandate is set out in the motion and it specifies that the Committee is to develop a science-based understanding of hydraulic fracturing and also allow for an informed public dialogue. To this end, we shall hear several presentations over the next two days concerning both the potential risks and benefits of hydraulic fracturing.

I'd like to welcome the visitors in the public gallery and our first presenter, Dr. Gilles Wendling. Dr. Wendling is a hydrogeologist who has been involved in the assessment of drinking water supplies and in the protection of ground-water resources.

Following Dr. Wendling's presentation, we'll take a short recess before proceeding with questions. If visitors in the public gallery would like to submit questions, forms and pencils are available at the entrance to the gallery and the page will collect the written questions forms at the end of Dr. Wendling's presentation.

After asking a few questions each, members of our Committee will randomly select written questions from those that have been submitted by visitors in the gallery. Time will not guarantee all public questions will be asked and answered, but we will do our very best with the time allotted. I would ask that questions and answers be kept brief and to the point so that we may deal with as many as possible.

Please note that these proceedings are being recorded and transcribed. If your question is selected, the information you fill out on the form may be read into the public record.

I'd like to remind all Committee members and Dr. Wendling to wait until they are recognized by the Chair before speaking. This will keep the discussion more orderly and allow those listening on the radio or over the Internet to know who is speaking. I would also ask that visitors in the gallery respect the rules of the Legislative Assembly. Visitors are not allowed to disrupt or interfere in the proceedings. Please refrain from making noise, including comments and applause, and mute any electronic devices.

We will now proceed with Dr. Wendling's presentation.

**Mr. Wendling:** Honourable Chair and dear members of the select committee, I really appreciate and I thank you for having me here today. I also want to thank the local First Nations for having us on their territory.

I'm going to talk about unconventional gas access to shale gas plays and the issue of hydraulic fracturing and the potential impacts on watersheds and groundwater.

Specifically, we will start with a few basic principles on access to shale gas and then we'll describe some concepts relative to groundwater. We'll talk about the issue of the sealing of shale gas wells. We'll then discuss surface water and groundwater interaction. We'll talk about monitoring and we'll finalize the presentation with conclusions and comments.

So first I want to tell you that we are not alone. This issue — hydraulic fracturing — is considered in many, many countries in the world and some countries have adopted moratoriums, some countries are doing hydraulic fracturing and some countries are thinking seriously about it. There are some very good reports that have been produced. I'm just presenting two of them here. One has been produced by Germany. They have completed a one-year risk assessment that included the comments from several groups with different expertise and the whole study was funded and paid by Exxon. There is another report following the studies completed in South Africa and I will be very pleased to give you access to these reports and give you copies of these reports, should you like it.

So first, a basic and very important concept is that shale gas is economical if you don't have to put pumps in wells to remove the gas from the shale gas plays. So the shale gas plays are zoned in the subsurface where the gas is under pressure. So, by leaving the wells to bleed the gas to the surface allows the removal of that gas in an economical fashion.

An example of zones where gas has been identified in the subsurface at high pressure — we are located here near Dawson Creek, which is south of the Peace River in the northern part of B.C. This is in an area where I have completed some investigations. The red indicates a zone in the subsurface where shale gas is present in high pressure in the Montney Plain, and this is the watershed of the Kiskatinaw River, which is used as a source of water for the drinking water supply for the City of Dawson Creek. So Dawson Creek was and is very concerned about the potential impact of the oil and gas industry on their drinking water supply.

The next slide is going to be a view of the subsurface along cross-section CC'.

So first we have distance on the X axis — zero kilometres, 10 kilometres, 50 kilometres, 75 kilometres — so you see the length of the cross-section. On the Y axis, I have elevation. Sea level is right here — zero metres — and I have

1,000 metres below ground level below sea level, 2,000 and 3,000 metres.

My topography — my land elevation is roughly at about 800 metres elevation. So there is a ratio of 1:10 in exaggeration in order to show the plays; otherwise, my illustration would just cover the very bottom part of my slide. Just realize that I'm expanding, in a way, the dimensions.

I have several colours on my slides. The yellow indicates horizons, plays, at depths where gas has been identified so they're mostly cold, dry plays.

There are other zones — other horizons, bedrock horizons — that have been encountered when drilling took place. The blue indicates that these horizons contain water. The green colour indicates zones in the subsurface — and they can be very thick — where both gas and water are present.

So first I want to pass the message that we have a mix of fluids in the subsurface and water can be encountered at very deep depths.

As I mentioned, the access to shale gas relies on the fact that the gas is under pressure. If you drill a well and you let, let's say, water move up into the well, this is the level it would reach — 700 metres above sea level. So you have a high equivalent water column corresponding to the pressure present in the gas play.

Other zones, as I mentioned, are present and they also have their own pressure. The Baldonnel is a water-bearing zone, and the pressure in the Baldonnel is indicated by this line here — at about a 600-metre elevation, slightly below ground level. The Cadotte is a very thin bedrock zone, which contains both gas and water. The pressure in the Cadotte is indicated by this red line, here — roughly at an elevation of 400. So you can see that there are many zones. Some contain gas. Some contain water. Some contain both gas and water. They are at different pressures.

Once a proponent has identified a gas play, their interest is to optimize the removal of that gas. As the layers are relatively thin, you can optimize the access to that zone by drilling horizontally. You have long pieces of pipe that connect to your play, and then, as the play is very dense, very compact and has a very low permeability, the intent of hydraulic fracturing is to create millions of micro-fractures that allow the gas to move to zones that are fractured and that are more permeable and to go toward the main stem of the well and have that gas be pushed under its own pressure up to the surface. That is the whole intent of hydraulic fracturing.

Also, when they hyrdrofrack, they inject what's called a "proppant". It is a mixture of water and sand, and the sand grains allow, when the fractures have been created, the fractures to be kept open. Then there are a series of chemicals that are used to enhance the removal of the gas and prevent the growth of slime due to bacterial activity that would slowly clog the well.

Once a zone has been identified, the intent is to maximize the access to that zone. You don't just go and frack along one length. You will frack along many lengths in order to create a blanket in the subsurface that will become very permeable and then will be able to allow the gas to move from a large area.

Due to this concept of passive movement of the gas under its own pressure, shale gas wells have a short lifespan. They will be very effective at the beginning when the pressure is high but, as soon as the pressure starts dropping, the production will decrease. This graph indicates the rate of production — 1,000 cubic feet per day, 2,000, 3,000, 6,000 — versus time, in months — 12 months, one year, two years, three years. You can see in the Horn River Basin, which is one of the key basins in B.C., that at the beginning, the well can be quite productive, almost close to 6,000 cubic feet per day. After one year, it is about 3,000, and look after three years, it's close to 1,000. So you can see the significant drop of the production versus time.

Of course, the industry will focus their first activities in the most productive zones, where the pressure is the highest. The first series of wells will be the best ones, and then the next generation of wells will have to tap into zones where the pressure is less. So, if they have committed to a certain level of production, they will need more wells in the second generation in order to meet the demand.

Think about the third generation and the fourth generation of wells — the wells have a very short lifespan. The more we go, the more wells we need to drill and the less productive the wells are, and so you get on a treadmill, which gets faster and faster and faster.

Let's talk about groundwater. Here I have a series of aquifers: aquifer 1, aquifer 2, aquifer 3. This is typical of what you find in nature. You can find aquifers — what is an aquifer? An aquifer is a zone in the subsurface where all the voids are filled with water. The voids can be the void between sand particles and gravel particles; they can be the voids offered by fractures in bedrock. Aquifers are characterized by the fact that they are saturated with water and also the water is under a certain level of pressure.

For aquifer 1, if we drill a well and if we let water rise in the well, it will reach a certain level. It will reach an equilibrium. That equilibrium will be representative of the pressure of the aquifer at that very location. This is what we call the elevation of the water table at that location. Here, aquifer 1 daylights to surface and we have a spring right here. We know the pressure of the water here, and we know the pressure of the water here. We can draw a line, and that will be indicative of the elevation of the water table for aquifer 1. The slope of the line indicates the direction of the groundwater in the aquifer. In our case, we have a high pressure here and a lower pressure here — like the downward trend of the water table — so groundwater is moving from left to right.

For aquifer 2, we have a different set of parameters, so at this location, look, the water level actually rises above ground level. This is called an artesian well. Water will flow at the top of the casing right here.

This aquifer daylights here in a flatter part of the land, and we have a wetland right here. This is the water table for aquifer 2. Why do we have a wetland? It is because we have groundwater daylighting and providing moisture to the vegetation right here.

Aquifer 3 is a deeper aquifer and it gives water to a river right here. So at the end of the summer, you can see that the groundwater coming from this aquifer would be critical to the sustainability of the system.

Then we have a target zone that can be one kilometre deep, two kilometres deep, three kilometres deep. This target zone is under very high pressure. Let’s assume we drill a well down to that zone to get access to the fluid there. The well is brand new; it has been very well completed and there is a very good seal along it — so there is no contact between this target zone and the various aquifers because of the good seal. Let’s assume that this well is 30 years old or 40 years old. The seal has degraded. It is not 100-percent sealed any more, so you will have voids. You will have cavities along the well which create pathways for the fluid under high pressure here. Fluids always move from the high-pressure zone to a low-pressure zone. In that case, the pressure being higher at that location, the trend for the fluid will be to move upward. It will discharge to zones of lower pressure.

If the fluid is of lower quality — it is known and accepted that liquids that can freeze at deeper depths — two kilometres, three kilometres deep — are most often very saline and they can contain arsenic and other metals. Why is that? Because they are older fluids and they have had more time to exchange with the environment and so this is why they are more loaded with metals, et cetera. So what may happen in that situation is that the discharge of these fluids of lower quality may affect the quality of my groundwater in these various aquifers and it may have a final impact on the springs, the wetlands and the river. It will take time, but it may happen.

On this slide, I have various aquifers: aquifer 1, aquifer 2, aquifer 3 — same thing, a sandwich of aquifers and aquitards. Aquitards are zones with very low permeability, so they would be considered as a barrier between aquifers. Every medium is permeable, but you have a wide range of permeability. So if a medium is a thousand times or ten thousand times more permeable than another medium, the less permeable medium will be considered impermeable because of the contrast in permeability.

So, aquifer 1 is recharged on the ridge right here. We have rain and snow, so meterological water reaches the water table. The water table is indicated by a slope here. Groundwater will move through aquifer 1 in that direction and look, we have a little river here and this river is connected to the aquifer. There is an intimate connection between surface water and groundwater here.

We have aquifer 2 at the lower pressure. This is the water table for aquifer 2. Let’s assume that we create pathways; let’s assume that we have straws connecting aquifer 1 and aquifer 2. If water is allowed to move through these pathways, it would move downward, because the pressure is higher here than here. That may take time but, over time, you will have an equilibrium — a new equilibrium that is going to be reached with the upper aquifer losing its pressure, so you will have a drop of the water table. On the contrary, for aquifer 2, we’ll have a mounding of the water table because it will receive water.

Look here: due to the drop of the water table, we have here a disconnect that is occurring between our river and the aquifer. So now the river won’t receive groundwater anymore from aquifer 1. Let’s assume now that aquifer 1 gets connected to aquifer 3, which is much deeper, and the pressure in aquifer 3 is quite high, as indicated by the water table right here. Low pressure system, high pressure system, conduits — we’ll have movement of the groundwater.

In that situation, due to the high pressure here and the lower pressure here, we’ll have an upward movement of liquids from aquifer 3 to aquifer 1. The water quality here may be different from the water quality here. We may modify the water quality at shallow depths due to this contact with the aquifer at deeper depths. So, I just wanted to present those basic physical concepts, because they drive how groundwater moves in the subsurface.

The industry has been active in oil and gas for many years, so we have a good knowledge of drilling, a good knowledge of sealing and we have many regulations to make it as safe as possible. As shown by this illustration from the German study, it shows that when you want to reach greater depths, you have to work telescopic, so you start with the launch diameter at surface. The launch diameter greater than 50 centimetres — you can see the scale with the hand here. Then you will install your first casing; then you are going to fill the void between the casing and the receiving bedrock to prevent any pathways from the surface to deeper depths. Then you keep going down, you install your second casing, you will grout the space between the large casing and the small casing, et cetera, and you go down. Typically you work with the three diameters, as indicated on that illustration.

So there are many regulations, but I think there are limitations too, and we are going to discuss that. This is an old slide that I got many years ago from the Alberta Energy Board, so I just went through that illustration to acknowledge that even the regulating agencies accept that there are weaknesses in seals of wells. There are many locations along the inside of the casing, outside of the casing, through the concrete or grout seal at the boundary of the seal, and the receiving environment — there are many locations, many potential weaknesses — microfractures in the cement, fractures due to shrinking of the cement, fractures due to corrosion of the casing. So fluids will find ways. There will be pathways created with fluids. It can be done quickly if the well is poorly completed or it can happen after one year, five years, 10 years or 20 years, depending on all the geochemical reactions that can take place at that depth.

It is an extremely important topic, so it’s a topic which is presently being scrutinized. The Environmental Protection Agency in the States — during this process of reviewing the state of the knowledge — there was a series of presentations that was presented last year. You can go on-line on the EPA website and download all the slides of the presentations.

My next few slides are from these presentations. I selected some from Bill Carey, who works with the Los Alamos National Laboratory. He presents in his presentation how wellbore integrity can be achieved. What are the tools? You need to select the right ground, you need to select the right mix of cement and then you will choose a type of steel that won't corrode or corrode as little as possible.

However, he acknowledges that wells do leak and why they leak during installation and pre-production. For example, he mentioned the shrinkage of cement — we know that cement shrinks — so there will be fractures that will be due to the shrinkage of the cement. Post-production — disruption of cement-formation bond, fracture formation within cement, corrosion of steel casing. The subsurface is very active. As I mentioned, there are many types of bacteria in the subsurface and those bacteria will create geo-chemical reactions that will one day affect the cement and the steel.

Anthony Ingraffea and his team also looked at issues of wellbore integrity and failure mechanisms. You may be familiar with that slide that shows how wells are losing their capacity to fully contain the pressure over time, and this is based on data collected in the Gulf of Mexico, because a lot of drilling has taken place and they started, like, in the 60s, so we have started gathering information.

So when wells are relatively young — one year, two years old — a small percentage of the wells do not fully control the pressure but, as the wells age — you see the age of the well: four years, eight years, 20 years, 30 years. So you can see that, when the wells reach the 10-year-old age, 30 percent of them do not fully control the pressure and you can see the increasing trend. So over half of the wells do leak over time, according to that statistic.

For recent activities taking place in the eastern side of the States, Ingraffea and his team looked at the statistics, looked at the data. In 2010, six percent of the wells showed failure. Failure is a leaky well. In 2011, about seven percent; 2012, nine percent. So you see, there is always a percentage of wells that don't make it, that do leak.

Myself, I had the chance to be involved with a project in Alberta. At the time I reviewed their statistics, so every year they inspect certain numbers of wells and they rate them. In 2005, for the wells being inspected, 469 wells were inspected by their staff. Over 80 percent passed and 18.5 percent didn't pass — they were not in compliance; through the years 2006 to 2009 — so always around 15 percent or 20 percent of the wells were not completed according to the regulations. They had witnesses; they leaked.

The text here specifically refers to 10 casing failures that occurred at the enhanced heavy oil recovery operations in northeast Alberta, resulting in crossflow from the producing zone — so the deeper zone under pressure — into another formation. So there was movement of fluid between a zone that was known to zones much less known or unknown — so a loss of fluid, a migration of fluid — uncontrolled.

Back to the presentations available on EPA website, Matt Freeman from the Berkeley lab — they are working on modelling scenarios. So we have a vertical section of a well, the horizontal section with the fractured zones where hydrofracking is taking place, and they are considering the potential connection between fractured zones and an existing fault in the subsurface. So what will happen in the migration of fluids between this deeper part of the subsurface and the shallower part where we have an aquifer right here — so just to give you an example of how it looks when you create a numerical model — so you create the shell layer and then this is the vertical fracture and you have the aquifer with water wells. You model that, you input data into your model, you run it and you look at the results.

Through my review of the information presented, the key conclusions to date are that they are still working on it. They are going through the modelling right now. They say more studies are required. The EPA, on their website, says that they're going to release their report in 2014. I think it will be a very important report.

Are 100 percent of the wells sealed, and will that be forever? Why is it such an important question? Because surface water and groundwater are intimately connected.

I have an aquifer right here. This is its water table. There is a little well, with the pressure in the well. Groundwater is moving from left to right due to the water table. It discharges right here, where we have a river. The river will have a fluctuating level, depending on the time of the year. But during the dry period of the year, the river level will be low and will typically be lower than the water table. The aquifer will be providing water, groundwater, to that river. The aquifer will be the main provider of the water. That's extremely important.

Why is it important? Because it will maintain the baseflow. Also, groundwater is always at a constant temperature — typically eight degrees, nine degrees or 10 degrees, depending on where you are. It will be warmer than the glacial temperatures so it will prevent the full freezing of rivers.

The proportion of the groundwater discharging to the river will be a function of the elevation of the water table. The higher the water table, the more groundwater will move, and if you start dropping the water table, you will reduce the quantity, the flux, of groundwater discharging to your river.

Now let's go back to our cross-section and consider that we are 30 years down the road, 40 years down the road. A bunch of wells will have been drilled. The pressure will have dropped so all the currents that you see here won't be there any more — gone. The pressure is gone. We'll have created wells — a certain percentage of them not being properly sealed any more. So we'll have pathways between formations, each formation originally having its own pressure, but due to the pathways and due to the difference of pressure, we'll have a new equilibrium that is going to be reached. What is this equilibrium going to look like? I don't know. I don't know if you know, but tell me.

Zooming in on one potential scenario just to clarify what I was just saying, let's assume that we are in a zone where many wells have been drilled. This is a zone also where we have existing natural fractures in the subsurface.

Let's focus on the Cadotte, which is one of the top, deep bedrock zones that contain water. So there is water in the Cadotte. It's under a certain pressure. We know it's much lower than the ground level, so let's say approximately 500 metres below ground level. So we have a system containing water — like an aquifer — with a low pressure. We have at surface a bunch of surficial aquifers, which are five-metres deep, 10-metres deep. They are connected to the springs, the rivers and the wetlands. This is my aquifer and this is the pressure in my aquifer if I have a well — high-pressure system, low-pressure system, a bunch of wells. Let's assume that in 30 years, 10 percent of them fail — 15 percent of them are not sealed any more. We now have pathways where liquid can move from a high-pressure system, from a low-pressure system. In which direction is it going to move? It is going to move downward. What is going to happen to the water table here? Is it going to drop by one millimetre, 10 centimetres, one metre, five metres? I don't know. Do you know?

Why is it important? Is my water table going to drop by a metre, by five metres? What is the level of my invert here? If I have a little shallow lake — we have many ponds, like in northern B.C. and in the flatter areas of the country. We have very a shallow system, so it's very complex — the connection between the groundwater and the surface water is extremely complex. If we start playing with or messing with the water table here, we have to be aware of the potential consequences of that.

So I was fortunate to work with the modelling team from the University of Quebec in Chicoutimi and we created this scenario where have this surficial aquifer, we have a frack zone and then we have wells, and we have also native existing fractures in the subsurface. What is going to happen over time if we put them in contact, assuming that 10 percent to 20 percent are poorly sealed?

We did the modelling. It was presented in a paper called "*Modeling the impacts of shale gas extraction on groundwater and surface water resources"*. It was presented last fall in Montreal at GeoMontreal. The conclusion of our modelling is that the drawdown can range between .6 and .9 metres after three to five years — roughly up to a metre of drop of the water table. In the Horn River Basin, we have, as I mentioned, many ponds, small lakes — 50 metres in radius, 100 metres in radius, 500 metres in radius. They are very shallow. The majority of them are less than a metre deep. So, if you start playing with the water table, dropping the water table by .9 metres, how many of these ponds are going to disappear?

The effects will be permanent and irreversible once the fractures have been reactivated due to fracturing; once the frack zone or the fractures have been kept open by sand particles, they will be permeable. We are going to permanently modify the subsurface. We may create big deep drains. Okay? It would be impossible to fix. It's done. You can't push the refresh button or "Oops, we made a mistake. Let's go back 30 years."

It could be devastating for watersheds and their ecosystems due to the interconnection between groundwater and surface water. What we see at surface is surface water. We don't see the groundwater, but it's there. It's very active; it's very dynamic; it plays a key role.

We don't say that we have found great results. There may be many weaknesses in our modelling and in what we have done, but we need to have a debate. We need to have many teams doing similar types of models. We know it's happening in Berkeley. We also want the industry to do that; to come with their results so we can share notes. Is it an issue? Should we be worried about it? Or no, the risks are very small? We need to know and we need to know before there are 1,000 wells or 5,000 wells or 10,000 wells in the ground. It would be too late.

Are there deep natural pathways in the subsurface? I was involved in a study about 10 years ago, when I was requested to provide an understanding about the source of the Liard Hot Springs. Why do we have water daylighting at 60 degrees celsius?

So we did this study and we confirmed that the water that was daylighting in the Liard Hot Springs — so we have a little cartoon showing the valley with the hot springs and there are ridges on both sides and this is the depth in kilometres — one kilometre above ground, sea level, minus one kilometre, et cetera. Through our research, we were able to confirm that we were dealing with rainwater and snow, which was a source of the hot spring, and the water — looking at the geochemistry of the water, the fingerprints of the water — we got the expertise from Steve Grasby who is the expert in hot springs in Canada. He told us that this water had reached a temperature of 120 degrees. Then we looked — where do we find such a temperature in the subsurface? So, looking at the thermal gradient in the bedrock, we were able to estimate that at 3.4 kilometres we had this temperature of 120 degrees celsius. Based on our little research, we figured out that the water was precipitating on the ridge, following some fractures in the subsurface and going to a depth of 3.4 kilometres before finding its way back to surface and daylighting at the Liard Hot Springs. For me it was a real discovery, almost a shock. I said, "Oh my gosh, water can move quite deep in the subsurface." Right?

I think one of the key positions of the industry when they consider deep fracking and reaching the shale plays of three kilometres, four kilometres, they say, "Okay, it's completely disconnected. What is happening at the surface and what is happening at the depth are two different worlds — two different universes. You don't have to worry about it." Should we worry about it? Are we sure they are fully disconnected everywhere?

You have hot springs in the Yukon, indicated by the red dots here. I have also indicated the location of the shale plays proposed for activities if you decide to move forward. Zooming in on the lower part of the Yukon, you have the

Whitehorse Trough with some hot springs and you have the Laird Basin with some hot springs. So how is groundwater moving in the subsurface in this region? Zooming in the Whitehorse Trough, you have the springs. I also wanted to show the location of the faults. Faults are big fractures in the rock due to historical movement due to tectonic plates and pressures applied through bedrock over the last million years. So these faults are indicated by big lines here. You can imagine big fractures going very deep into the subsurface, so we don't have one or two of them here. I haven't counted them but there are quite a few. We have hot springs, we have big faults. So if you overlay hundreds or thousands of dots corresponding to shale gas wells, how will they interact? Can we have shale gas wells very safe in their own world, disconnected from nature?

Let's talk about monitoring. What do we know about surface water and groundwater? You can go on-line. There is the Yukon Water website which presents your present knowledge of surface water and groundwater. So there are approximately one thousand locations in the territory where data is being collected on surface water — temperature, flow rates, et cetera. At some of the dots, you have many, many locations — many sites — where surface water is being monitored. So you see roughly the distribution and the location where information is available on surface water.

For groundwater, there are seven monitoring stations being monitored by the territorial agency. So it's a big territory, but very few locations where we look at groundwater and check groundwater. I overlaid the shale gas plays and the groundwater monitoring stations. There is only play where we have one location around Whitehorse where we have information. We are extremely ignorant about groundwater. We don't know where our aquifers are. Even the shallow aquifers — we don't know where they are. We don't know how big they are. We don't know how deep they are. We don't know the water table elevation. We don't even know in which direction the groundwater moves. We don't know; we haven't collected the information.

What we should know: I think we should know first what's coming. If industry says, "We are interested in partnering with you, we're interested in developing the activities here," we need to know the full build-out plan, not 10 wells at a time. Do you want 500 wells, 1,000 wells, 5,000 wells in this area? It's important to know the final picture. Right now we work with a system of applications where only a small number of wells are considered per application — 10 wells here, 15 wells here. "Is it okay?" "Maybe, sure you can." But once they have moved in and 200 wells have been drilled, 500 wells have been drilled, there is a lot of infrastructure that is being built with that — the roads and the pipeline. For them it's — 30 percent of the investment is there, but they want 100 percent in order to have a full return. So the pressure will be extremely high to say, "Okay, no. After 50 wells, that's enough; we can't go any further."

In terms of field build-out plans, the designers and the owners of the leases in Houston or in Kuala Lumpur, in Beijing — they know the final build-out plan. They have billions at stake. They want their return. So when they say, "Oh, we don't know, sorry. Come back in a year or come back in two years," put the pressure on — "No, we want the information now."

This is the situation in northeast B.C. So we have Fort St. John hidden behind the dots here; we have Dawson Creek. Each dot is one well. Over 31,000 holes in the ground in northeast B.C. and B.C. is going full-speed ahead. There will be many, many dots filling the voids here.

Putting things into perspective, we have Yukon with no black dots and we have B.C. with the Fort Nelson First Nation territory here. You see all the big black dots here, all the small black dots? This is a well. We have over 4,000 wells in the northeast part of B.C. So how — if you say yes to hydrofracking — what is the Yukon going to look like 30 years from now?

For every wellsite, I think we need to define how water moves around that wellsite. So this is a drilling pad, which is a series of wells. There will be people working and living around, so they will need drinking water, so we have a drinking water well. They will also generate flowback water that will generate waste. That waste, that liquid waste, will need to be disposed of. Right now it is being disposed of in old wells. We have shallow aquifers, deeper aquifers, with their groundwater discharging to surface water — to a creek, in my illustration. So I think for every site or every region we need to understand that. We need to build that picture, not a little cartoon, but based on facts, based on information that we will collect. We need to know the shallow aquifers; we need to know the deeper aquifers.

We also need to better —

**Chair:** Excuse me, please. Dr. Wendling. We are running short of time. I wonder if you could wrap up in about a minute.

**Mr. Wendling:** I will finish very shortly.

So we also need to know what's happening with the various zones that contain water at depths — at 500 metres, one kilometre, 1.5 kilometres. We need to understand that and then we need to put the two together. This is at scale, this is my system at shallow depth — 100 metres, 200 metres, 300 metres depth — and then we go down two, 2.5, three kilometres, we frack. We have a disposal well. What is going to happen to the story of water around that site? What will happen to the creek that is down the road? We need to know.

With groundwater, things can be delayed. We won't see it two weeks later or a month later. It will be a year later, five years later, 10 years later. So it needs to be assessed. It needs to be modelled so we can project in time and look at the effects long term, even 100 years, 200 years. We need to know what's going to happen. We need to know what we're going to leave to our kids and grandkids.

Cumulative effects — I just talked about the subsurface and the shallow water. What about the roads, the pads, the pipelines? Cumulative effects are extremely complex to assess, but it needs to be addressed before we start.

We have many wells in western Canada — over half a million wells — so when you look at the potential of these wells to start leaking — and if you look at 10 percent of the wells, 50,000 wells will actually be path wells — they will be straws connecting systems at various depths in the subsurface.

You have permafrost. This is a very complex system. When you drill a well, you will drill through permafrost. You will have it in operation for four years or more. You have very warm gases at depths. What will happen along the casing of the well? Will the permafrost start melting? You are going to start creating a new pathway. What's going to happen with the shallow surface water pounding here? Is it going to move downward along that and then you're going to lose your surface water? I don't know, but we need to know.

You are dealing with a very sensitive environment. You know that; you live here. So are 100 percent of the wells sealed? Will they be sealed forever? Are we sure about it? What is going to happen to water if this is not the case?

Thank you very much.

**Chair:** Thank you, Dr. Wendling. The Committee is going to take a brief recess now. We'll reconvene at 9:35. The questions should be picked up by the page at this time. Thank you.

*Recess*

**Chair:** Order please. We are going to now proceed with questions for Dr. Wendling. As mentioned earlier, I would like to remind the members to wait until you are recognized by the Chair and your microphone is on before speaking.

I am going to start with a question from myself, Patti McLeod. Dr. Wendling, are you aware of any confirmed problems with the Kiskatinaw River watershed and the Montney play?

**Mr. Wendling:** The Kiskatinaw River has suffered from some extreme low flows. In 2011 in particular, they had to go into a drastic stage of water conservation because of the extreme low flow of the Kiskatinaw River.

**Chair:** Was that determined to be a natural state of the watershed or was it directly attributed to the Montney play?

**Mr. Wendling:** The Kiskatinaw River watershed is suffering from an extreme lack of data and data gathering, and the work that we have done included the involvement of UNBC to set some monitoring stations along the river to start monitoring the flow of the tributaries, et cetera. So, to answer your question, no, we were not able to come up with a strong conclusion that this is related to the gas extraction because of lack of information and lack of baseline, but the question is still up in the air.

**Ms. Moorcroft:** Thank you for your presentation, Dr. Wendling, and welcome to those people in the gallery and listening to the public proceedings on the radio and on television.

I want to acknowledge that we're on the traditional territory of the Kwanlin Dun First Nation and Ta'an Kwäch'än Council. My question flows from the words of respected Tagish and Tlingit elder Mrs. Angela Sidney, who said her peoples were part of the land, part of the water. Water is vital for life.

Based on what we know now, can we guarantee that the water will always be safe in the short term and in the long term if hydraulic fracturing takes place? And perhaps, in responding to that, you could address the issue of what information about water should be collected and for how long to have adequate baseline data to determine the effects of hydraulic fracturing.

**Mr. Wendling:** To answer your question, are we safe and will we always be safe? Should we allow hydraulic fracturing? As you have probably understood from my presentation, I think that the risks are high.

I believe that the movement of water in nature is extremely complex and we are just scratching the surface. We live in a beautiful land, but in a land where very little data has been gathered. We are almost starting from zero.

I believe it is extremely important to develop a proper network of locations and monitoring stations, both for surface water and groundwater, in order to start our knowledge and improve our knowledge. I think it's a long-term process, and not only being concerned about hydraulic fracturing, but also, if you look at the other activities — mining and other activities and other activities that may pop up five years from now, 10 years from now, 20 years from now — I don't know in 20 years what will be the new industry that will need access to water or that may have impacts on watersheds. I think for us and for the future generations, it's extremely important that we be responsible and stewards of this extremely important resource that is water. I don't think there is anybody in the room today who doesn't recognize the importance and the fact that life depends on the water.

**Ms. Moorcroft:** There are different studies from different jurisdictions. Not a lot of baseline water data has been gathered prior to development in many jurisdictions, and so I'd like to follow up with asking you, in your professional opinion, have any jurisdictions done adequate baseline water data gathering?

**Mr. Wendling:** I think, unfortunately, in Canada we are suffering from a lack of general water strategy. There is no water strategy coming from the federal government, so each province and most local governments are responsible for coming up with the definition of water strategies and plans. I acknowledge that one of the limitations is funding. It takes money to install gating stations on rivers, to install monitoring wells. So, I realize that but I think we need to make choices and we need to assign and dedicate adequate funding to start and build those key monitoring networks that will benefit us now for decision-making now — and the more data collected over time, the better position we'll have to make wise decisions.

In terms of other jurisdictions, I think we are still — when you talk of —

**Chair:** Excuse me, Dr. Wendling. We'll have to move on from that question.

**Mr. Silver:** Thank you, Madam Chair. Thanks to everybody for taking time out of their busy schedules today to be with us here today in the gallery and on the radio.

I think the most impressive part of your presentation was this shift of equilibrium that you just spoke of. What are the potential ecological ramifications of this, other than the disturbance of the water table, and what publications currently study these effects? The second part of that is, are there any publications on the shift of the water table specifically in aggressive, unconventional gas plays like in northern B.C. and Alberta?

**Mr. Wendling:** Unfortunately, very little work is being conducted. So I am pleased to stay in touch with the select committee and provide you with information that I have now and the information that will come and keep you aware of developments. It's a very hot topic, but there are very, very few publications on the subject here in Canada and even in the States.

**Mr. Silver:** Dr. Wendling, could you explain to the Committee and those listening who are the Council of Canadian Academies? How important is the Council of Canadian Academies' report on fracturing for our debate? I believe the report is ready. Would you know of why there would be any delays of this publication?

**Mr. Wendling:** There is an initiative presently conducted by the Council of Canadian Academies and so they are in the process. I believe that the reporting is coming in the next few months about the status of the knowledge in Canada. So there are teams back east, there are teams in Alberta and there are teams in B.C working on the subject. As I mentioned, a lot of work in progress but, right now, very little publication. You can see also in the States it's a very important issue; it's a very public issue. But as you can see, they are also in the data-gathering mode and they are doing their homework and trying to beat time, because time is pressing.

**Mr. Silver:** I'm going to pass on so we can get some more gallery questions.

**Hon. Mr. Dixon:** Dr. Wendling, is the degradation of either the steel or cement casings involved in the well an inevitability or is it something that can be mitigated through engineering and proper construction?

**Mr. Wendling:** I believe that we are dealing with really long lengths of pipe — kilometres. So making sure that every metre is properly sealed will require a lot of energy, time and tools to do that. So I think we know that there are limitations due to the concrete, due to the steel and due to the interaction of the various elements present in the subsurface, so I think it's a fact that wells will leak.

I understand that that needs to be better addressed and are there any mitigative measures that can be put into place? Yes, there are some. I think, ideally, wells should be monitored — I'm just throwing out some numbers here — maybe every two or three years; check their sealing capacity and, if they are observed to be leaking, then we could do some additional grouting, we could drill next to the wells to inject clouds of grout, but that would be very costly.

So who is going to pay for that? Will there be money set aside for the next five years, 10, 20, 50 and 100 years from now? If wells are observed to be leaking, who is going to fix them and who is going to pay for that fixing?

**Hon. Mr. Dixon:** The comparison with British Columbia is a little difficult because of the scale of development. Do you feel that we have a unique opportunity here given the fact that we are starting at basically zero to manage the scale of development, and how much does that scale of development impact some of the concerns that you have expressed today?

**Mr. Wendling:** I would say yes, in a measure, you are lucky that there are not too many holes in the ground. Yes, I think for you it's very important to foresee the various scenarios — how it could unfold and the scale at which it could unfold. I think this is critical. Would the industry be happy with 50 wells in the Whitehorse Trough and 100 wells in the Liard Basin or for them it's a no-go? What they want is 2,000 wells here and 5,000 wells here. They have an economic plan. I think you need to have an open discussion with industry on that. You need to understand what I mentioned. What is the built-out picture, right? Then I think it's critical to ask to have a proper baseline defined before we start. Because once the wells are drilled and say, "Okay, are there any impacts? Yes or no?" If you don't have the information, pre-building, there is no way you can compare. If methane shows up in your water, they say, "Oh, that's natural. That's a natural pathway. It was like that before we fracked." If you can't prove it, you can't prove it's a no. So you need to know before what the quality of your water is in the streams. You need to know before the water level in the aquifers. We won't be able 20 years from now to quantify a drop in the water table if we don't know what it is today.

**Mr. Tredger:** Thank you Dr. Wendling for the presentation. I would also like to thank the citizens of Yukon for their interest in hydraulic fracturing.

Dr. Wendling, you mentioned that you worked in the Dawson Creek area of northeastern B.C. and some 31,000 wells were drilled in the area, yet you used stats on wellbore integrity from the Gulf of Mexico and from northeastern Alberta. Are the wells in northeastern B.C. being adequately monitored for wellbore integrity over time? Are those results available to landowners, to First Nations, and to scientists so they can study them? Given that 10 to 20 percent of the wells fail in other areas, what happens in northeastern B.C. and what is the likelihood of groundwater already or eventually becoming contaminated by leaking wells?

**Mr. Wendling:** To my knowledge, that would be under the jurisdiction of the B.C. Oil and Gas Commission. Based on communication that I had with the OGC about two years ago on the subject, they were not collecting that type of information. They may be today, so I think it would be very worthwhile for you to check that. To my knowledge, such follow-up and assessment of well integrity is not being conducted and is not being reported.

The second part of your question relates to that — we are still in the dark regarding the real effects because of the lack of monitoring of conditions pre-drilling and even the lack of monitoring right now. There is very little information.

To my knowledge, the monitoring of the plays present at 500 meters, 1 kilometre, 1.5 kilometres are not being monitored. I am not aware, in B.C., of any monitoring of wells specifically following up the pressure of the groundwater in these zones. It costs money to drill these wells, the money is spent on drilling deep wells, accessing the gas plays and fracking the gas plays. The money is not spent on monitoring groundwater.

**Mr. Tredger:** I'll pass, so we can get to the gallery.

**Mr. Elias:** Thank you, Madam Chair, and thank you, Dr. Wendling, for accepting our invitation to come here and have a dialogue with us and with Yukoners. Thank you to those Yukoners out there who are listening and I hope some students are listening as well.

My question is about wellbore integrity and the migration of formation fluids to surface. In your presentation, you mentioned ways that formation fluids that can get to surface and contaminate groundwater. What do you say to industry when they say that they have ultrasonic imaging tools that can map a 360-degree picture of the wellbore right from surface to the end using cement bond logs — also drilling shallow hydro-geological wells and using isotope analysis at various stages to help fingerprint, if formation water comes to the surface, that this company A or company B — because we know what fluids that you have put in the underground have come to surface, it's a fingerprint.

What do you say to industry that says, "We have this under control and that we have no record of formation water coming to surface?"

**Mr. Wendling:** Your first question refers to how we can monitor the integrity of wells using available technology. Yes, we can log wells; we can measure the density of the material of the ground around casings, but any technology has limitations.

Also, you will have a good understanding of the status of your well at a given time. What is happening five metres, 10 metres away, 20 metres away from your well? That knowledge decreases drastically as you move away from your well.

In terms of the assessment of the effects of fracking, it's really a function of the tool that you have to measure the potential impact. If you don't have a dense network of monitoring wells located 50 metres, 100 metres or 300 metres away from your well — or one kilometre away from your well at a depth of 500 metres, one kilometre or 1.5 kilometres — we can say that if you don't have those tools to measure and to observe any impacts, then there is no impact. So I think this is really a complex situation we are in and for the industry, as I mentioned, it's very expensive to deploy very complex networks of monitoring systems. We need them.

There are some jurisdictions — like in Quebec, in particular — they are requesting that a network of monitoring be installed and that data be collected prior to the operation's start, in order to create this baseline and start building this knowledge. So I think the lack of information is key in saying we don't observe anything because we don't look for the problem. Do you see my point?

**Chair:** Thank you, Mr. Elias. Your time has elapsed.

We are going to proceed with some questions from the public gallery. This is a random pick. Question from Marguerite Roberts: "Fracking all of these wells will require huge volumes of water, more than can be imagined. What is the risk to surface water and groundwater systems undergoing such high depletion rates?"

**Mr. Wendling:** That is a very good question and a very important question. Why? Because a lot of water is required when building roads, drilling wells and fracking. So the capacity of nature to provide that water is very limited, so once again we need to properly assess what nature can provide in order to deliver that water during operations and during fracking. We need to better assess the vulnerability if you want to have some activities in the winter when the ground is very hard and when it is easy to mobilize heavy equipment. This is also the time of the year when the flow in the rivers is the lowest and is very vulnerable to any extraction.

Having a good knowledge of existing water budgets, available quantity of water that could be provided to the industry and then almost the full life cycle of that water — they are going to take the water; they are going to inject it. What is going to come to that water? Then there will be some flowback water; there will be some waste that is going to be generated. What is going to happen to this waste?

Right now I understand there are some activities in the Northwest Territories and they are trucking the waste water down to B.C. — thousands of kilometres, trucks going down the road carrying liquid waste. Does it make sense? I'm throwing the question to you.

**Ms. Moorcroft:** This question is from Matt Hutchison from the Yukon Geological Survey: The Gulf of Mexico is one of the most extreme drilling environments in the world, both deep water and structurally complex, and well-leak statistics potentially reflect this. It is not appropriate to use and compare those data from conventional wells here to the surface drilling environment in the Yukon. Please comment.

**Mr. Wendling:** I think this is one type of statistic that we have, so I think we can get some information from what has happened in the Gulf of Mexico due to the quantity of wells and the history they have there — the Deepwater Horizon well was a good example of how things can go wrong and how huge the impact can be on the environment.

Going back to comparing what is happening to the Gulf of Mexico to what's happening in the eastern United States or to Alberta or B.C., I think each place will have its own characteristics. It's important to gather statistics on the operations and the problems and the lack of sealing of wells in each jurisdiction. But as I mentioned, it needs to be done in

B.C. right now. We are not really focusing much on that. I think in order to compare, you need information. So we need to gather information and we are lacking that type of information.

**Mr. Silver:** This question comes from Marguerite Roberts.

What is your knowledge on the integrity of deep-injection wells? What happens to the liquid stored there? Will they eventually bubble up and contaminate groundwater?

**Mr. Wendling:** It is not being monitored. In B.C., you can operate disposal wells. The only information required is the volume of liquid waste being disposed in the disposal wells and the pressure at which you inject these liquids. What happens at the bottom of the hole if the hole is operating as designed? There are no deep monitoring wells checking what's happening with that injected, disposed fluid and the fate of that fluid. Is that fluid staying at depths? Is it connecting to existing fractures? Is it discharging 10 kilometres down the road somewhere? We don't know. It is not being assessed. It is not being monitored.

**Hon. Mr. Dixon:** This question is from Matt Hutchison of the Yukon Geological Survey.

Please clarify the specific risks of fracking on groundwater — the concepts you present — well integrity, water table movement, water aquifer contamination — are all equally applicable to conventional vertical production.

So I guess the question is: what is new about fracking that's not similar with conventional —

**Mr. Wendling:** I think I'm going to put myself in a waiting mode. I'm really looking to the EPA reports. I'm looking to the Canadian Academies' report that will provide a picture and a data picture of what we know the risks we are facing and also what we don't know and the big void of information and unknowns that we have. I don't have the answer.

**Mr. Tredger:** A question from Marguerite Roberts: if the groundwater and/or aquifers become contaminated, how would they be cleaned up?

**Mr. Wendling:** It will require a lot of time and a lot of money. Aquifer contamination has been observed and water supply systems had to find alternative solutions to provide water to the population. It ended up with millions in cost, either to find other alternative solutions to install pipe to get access to another water source. So aquifers are very sensitive. They are vulnerable. They are very complex. They are not always easy to access.

So, once you have contaminated an aquifer, it will be extremely complex to remediate it. It will take a lot of time and a lot of energy and a lot of money.

**Mr. Elias:** This question is from Robin Gilson. The question is: Given the large number of wells yet to be drilled in northeastern B.C., explain why there is a high risk of groundwater eventually becoming contaminated by leaking wells and the contaminated flowback water. What are the migration dangers for this?

**Mr. Wendling:** When you start dealing with deep fluids, you are dealing with fluids that are of poor quality, and if you start mixing liquids of very poor quality with fresh water, then you will degrade the quality of the fresh water and you will impact the quality of the shallow aquifers that contain the fresh water.

I'm sorry — I missed the second part of the question.

**Ms. Moorcroft:** This next question is from Don Roberts. In your opinion, given the large number of wells yet to be drilled in northeastern B.C., explain why there is a high risk of groundwater eventually becoming contaminated by leaking wells. How long do you expect it to take for cumulative impacts to become apparent?

**Mr. Wendling:** I think it's really the question I mentioned. It is sensitive, and if we have a certain percentage of the wells that do fail and do leak, the larger the number of wells you're dealing with — if you're dealing with 1,000, 5,000, 10,000 wells — you drastically increase the risk of having migration and having contacts between poor quality water or injected frack water to aquifers. So I think that the larger the numbers, the higher the risks.

**Mr. Silver:** I am going to have to pick another question. This is from Davina Harker, but it is the exact same question about the integrity of deep water injection wells.

This one is from Matt Hutchison from the Yukon Geological Survey. Please clarify how water migrates into impermeable rocks alter fracking to act as a drain: (a) the rocks are impermeable; and (b) the fracture zone is typically an order of magnitude less in thickness relative to the total thickness of the shale play. Please comment.

**Mr. Wendling:** I think there are some faults. There are some natural fractures present in the subsurface, so that has to be taken into consideration.

We also know that fracking creates, I would say, small earthquakes of lower magnitudes, so there is a high level of energy being released during fracking. How that will impact existing weaknesses in the subsurface still needs to be properly assessed. How are the voids in the bedrock going to be modified due to this shaking of the subsurface?

Once again, I think we need more modelling, we need more tools to generate the scenarios that we are facing, and we need those tools properly calibrated and properly compared between various teams developing those tools to come up with the best result, with the best level of knowledge. We are still in the midst of that. I think we shouldn't just deny — "Oh, the risk is very low," and not look at the issue. I think if we identify there is a little risk, we need to better define that risk and then we can say, "This is acceptable. There is a five-percent level of risk or 85-percent level of risk," and then it should become a social debate. We can't control everything, we can't know everything, but we need to reach a high level of knowledge before making critical decisions.

**Hon. Mr. Dixon:** This question is from Rob Lewis from Whitehorse and there is a bit of repetition here, so perhaps if you have anything new to add: What do you know about the integrity of deep injection wells? What happens to the liquid stored there?

Again, if you have anything new to add.

**Mr. Wendling:** Once again, I think it's a very important question because also an important part of the answer is that the wells used for disposal of liquid waste are the old ones. In B.C. we're dealing with disposal wells that are 40 years old, 50 years old. So what has happened in terms of degradation of the parts of the well over the last 50 years? If we don't monitor it, we don't know, so I think once again we are dealing with a big black box down there at 1.5 kilometres.

What is the integrity of that black box? Is the black box functioning as we think it is functioning?

**Mr. Tredger:** Again, this is similar to a previous question.

Fracking all these wells will require huge volumes of water. What is the risk to surface water, groundwater systems undergoing such high depletion rates? What affect will it have on the groundwater level?

**Mr. Wendling:** I think once again we have to imagine that our rivers will lose 10 percent, 20 percent, 50 percent of their low flow. Is this an acceptable situation? Will fish habitat, fish and people suffer from that? If stretches of small tributaries are going to become dry, is it something that we accept? If we say okay, that's the cost, that's the price to pay — sure, we are going to sacrifice some pieces of our watersheds because this is going to happen. So if people say, "Yes, sure, I agree with that," then let's do it. If we think no, we don't want rivers to run dry, then we have to take all the measures to prevent them from running dry.

**Mr. Elias:** Apparently we have run out of questions from the gallery, and I don't have any questions.

**Chair:** The page is going to collect a few more questions. We have six minutes left for this section of our meeting here today.

**Mr. Silver:** Dr. Wendling, is it your opinion that these deep-water disposal wells are the best method for disposal of these contaminated frack fluids?

**Mr. Wendling:** Right now this is a solution that is being used because it is economical. The treatment of liquid waste is not required before disposal, so there is no additional cost associated with treatment. There could be a solution of requiring the industry to treat the liquid waste to an acceptable level before it is discharged back to the environment — whatever the fate, the final destination, of that waste is. That would be the safest position for the environment. There is a cost to that.

**Ms. Moorcroft:** Thank you, Dr. Wendling. My next question relates to permafrost. We've heard about the interconnectedness of ground and surface waters. We know that there's not a lot of data about groundwater in the Yukon. In active exploratory drilling occurring in an area of the Yukon that has a large amount of permafrost, what studies and modelling have been done for drilling in permafrost areas?

**Mr. Wendling:** I am not aware of any. That does not mean that none have been done. But I think that permafrost is very complex, the movement and presence of groundwater in permafrost is extremely complex and the disturbance of permafrost due to drilling or infrastructure — road building, pad building — I think needs to be properly understood and addressed before seeing some impacts that could be quite negative.

**Chair:** I'm going to ask Mr. Elias to ask one final public question.

**Mr. Elias:** It doesn't say who this is from but it says: will the water at 120 degrees underground around the hotspring up in the north cause more climate warming if they drill one or many wells that deep?

I guess they are talking about in and around the hotsprings there and its relations to climate change.

**Mr. Wendling:** Hot springs for me are — I brought the issue just to show how complex groundwater can move in the subsurface and how water from surface can at some locations find a pathway to very deep depths to reach high temperature and then finding pathways back up to surface to daylight, and this is what we see when we see hotsprings. I understand that there are many locations not reported as hotsprings in the Yukon, but where warmer water is being observed, where snow melts earlier in the season. That really reflects the complexity of the groundwater movement in the subsurface.

I think this is fascinating and this is important and we need to be more aware and more knowledgeable about the movement of water at surface and subsurface. I really want to thank you for your attention. I thank you for the people sitting with us today and I want to thank you for having the opportunity to share what I know about groundwater today. Thank you.

**Chair:** Thank you, Dr. Wendling, and thank you to the public. Committee will be recessing for 15 minutes before we continue with our next presentation. It will be with the B.C. Oil and Gas Commission.

So that's a 10:30 start, thank you.

*Recess*

**Chair:** I want to welcome you back to the proceedings of the Yukon Legislative Assembly's Select Committee Regarding the Risks and Benefits of Hydraulic Fracturing.

For those joining us for this presentation, allow me to introduce the members of the Committee. I am Patti McLeod, the Chair of the Committee and member of the Legislative Assembly for Watson Lake. To my left is Lois Moorcroft, who is the Committee's Vice-Chair and Member for Copperbelt South. To Ms. Moorcroft's left is Sandy Silver, the Member for Klondike. Behind me is Darius Elias, the Member for Vuntut Gwitchin. To Mr. Elias' left is Jim Tredger, the Member for Mayo-Tatchun, and, finally, to Mr. Tredger's left is the Hon. Currie Dixon, the Member for Copperbelt North and Minister of Environment and Economic Development.

The Committee's mandate is set out in Motion No. 433, which specifies that the Committee is to develop a science-based understanding of hydraulic fracturing and also allow for an informed public dialogue. To this end, we will hear several presentations over the next two days concerning both the potential risks and benefits of hydraulic fracturing.

I'd like to welcome the visitors in the public gallery and our next presenters, Paul Jeakins and Kevin Parsonage from the B.C. Oil and Gas Commission. Mr. Jeakins and Mr. Parsonage will be sharing with us the commission's experience with regulating hydraulic fracturing in British Columbia.

First, Mr. Jeakins will be providing a general overview and then Mr. Parsonage will be presenting a more technical review of the B.C. Oil and Gas Commission's work.

Following the presentations, we will again take a short recess before proceeding with questions. If visitors in the public gallery would like to submit questions, forms and pencils are available at the entrance to the gallery, and the page will collect the written question forms five minutes prior to the end of the presentation. That's a slight change from this morning.

After asking a few questions each, members of our Committee will randomly select written questions from those that have been submitted by visitors in the gallery. Time, of course, will not guarantee all public questions will be asked and answered, but we'll do our best with the time allotted. Again, I would ask that questions and answers be kept brief and to the point so that we can deal with as many as possible. Please note that these proceedings are being recorded and transcribed. If your question is selected, the information you fill out on the form may be read into the public record.

I'd like to remind all Committee members and the presenters to wait until they are recognized by the Chair before speaking in order to activate the microphones. I would also ask that visitors in the gallery respect the rules of the Legislative Assembly. Visitors are not allowed to disrupt or interfere in the proceedings. Please refrain from making noise, including comments and applause, and mute any electronic devices.

We are now going to proceed with Mr. Jeakins' presentation.

**Mr. Jeakins:** Thank you very much, Madam Chair. I'll just get into our presentation here pretty quick. I have about 30 minutes and Kevin has about 20 minutes just to go over some of the technical aspects.

I'd like to thank the Yukon government for inviting us up here. It certainly is an honour to come up and discuss some of the things that we've gone through and the learnings we've gone through over the last few years in the development of an unconventional shale gas play. We'll get into some specifics about hydraulic fracturing as well, but we also have some broad overview topics we can get into.

So just a bit of the overview: Kevin is our supervisor for field engineering and technical investigation and I am the commissioner of the OGC. The commission has approximately 220 staff in six different offices throughout the province. I have been with the commission since 2005; Kevin has been there since 2006. We have certainly grown in our expertise over the last seven years within the commission in anticipation of the issues related to some of the things that you're hearing and talking about over the next couple of days.

So we will hit the highlights of what we're doing. Certainly there is a lot more expertise within the commission itself and a lot more information on our website, so if you have any issues or questions after we're finished, certainly there is a lot of information there.

The key for the commission has been continual improvement as things change and certainly as you will see in our presentation, things have dramatically changed in B.C. over the last few years. We certainly regulate oil and gas on behalf of all British Columbians. We are a provincial agency, so it's not just in the northeast, where most of the activity is taking place. We certainly aren't claiming perfection in how we're doing things now. We are continually changing and updating our processes and hopefully you'll see some of that as we go through it.

Just so you know, a dramatic shift in B.C. happened just fairly recently. The current industry-developed approach to developing shale plays is to use hydraulic fracturing. Five years ago, only 15 percent of our wells that were drilled in B.C. were actually targeting unconventional sources and that has now shifted to 90 percent. So we still have production from our conventional wells happening in B.C., but the shift in the industry has been to the unconventional and that has been hydraulic fracturing. So that was a dramatic shift for our province. Certainly similar to what Yukon is going through, we made every effort to learn from other jurisdictions that had already gone through this. A lot of what you'll see is based on our learnings as well as what we learned from other jurisdictions.

I've seen from other presentations here that you have already gone into some detail on the technical aspects of hydraulic fracturing and Kevin is going to get into a bit of that in terms of how we regulate that, but I'm not going to get into a great long technical discussion on how hydraulic fracturing works. There are better experts than me, I think, who are able to do that for you.

So we'll get into sort of how we reacted to the shift to hydraulic fracturing in the province. It is one way of extracting gas. Many of our regulations take into account other different ways to extract gas. Our regulations, you'll see, aren't just hydraulic fracturing-specific; they actually do talk to other extraction methods.

In terms of where our gas is in B.C. — our unconventional basins — we have four of them. As you can see there, there's the Liard Basin, Horn River Basin, Cordova Embayment in the northern part of the province and then the Montney Formation down around Fort St. John and Dawson Creek. A little later on in the presentation, I'll go into some detail about each of those basins. But that's where industry is operating right now mainly. Again, like I said, we have production from areas — unconventional areas outside of those — but for the most part our activity is now centred there. You can see there from those numbers — and again our website has a lot more information on that — but B.C. has a lot of gas in those four basins and we're certainly looking to develop those gas plays.

Our offices are also highlighted on the map there. I'm based out of Victoria. We have an engineering group based out of Kelowna. In our main office — most of the staff are up in Fort St. John. We have satellite offices in Dawson Creek and Fort Nelson, and we've just opened up some offices in northwest B.C. in anticipation of the liquefied natural gas. We have staff now operating out of Smithers and Terrace, and that is just recent, in the last month or so.

The B.C. Oil and Gas Commission was created in 1998. It grew mainly out of the ministry of energy and mines at that time, and petroleum resources. It brought together a number of different agencies in 1998. It has been a growing process for the commission in the 15 or 16 years since we have been around. I think we have solidified now, but it did take a number of years to get the cultures from the different agencies together.

As I said earlier, we regulate — we don't advocate for the oil and gas industry. You will see that in our presentation and I will get into a little bit of detail as to how we do that.

When the commission was set up in 1998, it was with the thought that it would be a single-window regulator, and that has been unique in Canada and it is also a full life-cycle regulator. That does provide us with unique expertise on each of those components. The single-window approach is being adopted now in Alberta. It's more efficient in terms of permitting for the single sector, and I think that has helped B.C. to be very nimble over the past little while in terms of reacting to natural gas development.

We don't develop the policy for the province, for provincial-level issues or values. We work very closely with the other government agencies on that, whether it's the Ministry of Environment, the Ministry of Natural Gas Development, or Forests, Lands and Natural Resource Operations.

We do have some ability to set some policy for our technical regulations, and again Kevin will get into that.

If it makes sense for us to regulate a value specifically for the oil and gas sector, that is something we talk about with the other government agencies, and then we will do our own internal analysis as to whether we take that on or not. We have changed over the last few years to take on a few more things.

In terms of the full life cycle, I will get into some of the detail of this a little bit later, but we would certainly be here quite a long time if we wanted to get into the full detail of this.

Pre-application starts with one of our regulations. It's a consultation/notification regulation — I'll get into that in a second. Then the application would come through the commission. We do First Nation consultation on behalf of the Crown as part of that application process. We do our own review and assessment of the application. We make a decision. If it is to go forward with a permit, we'll put terms and conditions on that and industry will start its processes, and then we'll get into our inspections and compliance, if necessary. Then, like I said, full life cycle means that we also work at site reclamation and restoration within the commission.

As far as First Nation consultation goes, as I said, we do that on behalf of the Crown. We fully expect that companies will work with First Nations in advance of the application coming in to us. In the Treaty 8 area of the province — so that's most of the northeast where most of the activity is taking place right now — we do have some interim agreements with the First Nations and we have some full consultation process agreements in place. They provide capacity funding for First Nations. They also do establish some timelines that we work with as a guidepost to having the application reviewed by the First Nation, but if there is more time needed to discuss mitigation, changes, comments or anything like that, we certainly will take that time. We have overlap with First Nations communities throughout the Treaty 8 area, so in some cases we'll be consulting with three First Nation communities on one application at a time. It is a fairly robust group that we've got within the commission. I'll get into a little more detail on that later.

In terms of landowner consultation/notification, as I said, we have a regulation specific for that. It is a requirement that the company consult or notify as defined by regulation in advance of the application coming to the commission.

The company will interact with the defined landowners or communities, or First Nations if it's about the reserve. They have 21 days for a potential recipient to respond to the applicant. The applicant will then respond back to the recipient. All of that information has to get bundled up and then sent over to the commission. Then the company will submit their full application with all of that information.

Now, within the legislation, a landowner can actually appeal to the Oil and Gas Appeal Tribunal set up to the *Oil and Gas Activities Act* if they feel that we didn't consider their application, or their comments, appropriately. We've had a number of appeals go through the commission and through OGAT in the last little while.

As far as the single window/full life cycle approach goes, it does give our staff a holistic kind of view. We interact quite well vertically and horizontally within the commission and with other government agencies. It really does look at the full aspects or issues related to oil and gas, whether they are environmental, social, technical or geological. We seek as much input as we can on those topics. As you can imagine, the interpretation of how to manage each of those things is fairly varied depending on who we are talking with. The law and regulations do spell out most of the policy, but there is always room for interpretation — or there is some need for interpretation — at the local level and the individual application level. We certainly do look at that at that level as well.

As I said, we went out and sought input into our processes. We've been certainly learning internationally as well as nationally throughout Canada. We have worked with a number of the provinces in Canada.

We work with the United States' regulators on a regular basis. We've gone to Europe. Europe has come over to see how we do things. The same with South America. Colombia has come to B.C. a couple of times and we've gone there to share some of our experiences. Australia and New Zealand — we certainly have looked at how they have made changes in their legislation and entertained some of their staff over in B.C. as well.

Historically we've focused on an individual application, whether that's a well, a pipeline or a facility. We still certainly dive into detail with permit conditions at the application level, at the permit level. But many of the values that we work with need to be managed on a broader scale — I'm going to get into that in a little bit of detail — so that's whether we're dealing with more than one First Nation, whether we're dealing with more than one company, whether we're considering ecosystem values as they function over much larger areas.

One of the things that we wanted to do is look at the direction that we take. Sorry, you can't see that too clearly. But at the top there is the strategic direction: what is the policy of the government, what are the laws, what are the inputs that we get at a broader scale. The strategic direction we get is mainly from government. We provide input into that. We have land use plans up in the northeast of the province. Certainly that provides some strategic direction. One of the things that we wanted to do at the commission is open up the tactical discussions, so a level below that strategic direction — so certainly a smaller land base area, a shorter time frame — and that's something I'll get into a little bit of detail in a minute.

Then at the operational level, that's the permitting level.

We have worked closely with the other agencies. We've started talking to First Nations about that tactical approach, so we're opening up the conversation to more than just one permit at a time.

Our initial response to that — and this is the Liard Basin, just outlined there for you — has been our area-based analysis. So that is our recent tactical tool to look at larger areas for issues.

Like I said, there are land and resource management plans in place that guide some of this, but the area-based analysis goes into more detail and gathers together all of the data. B.C. has just a wealth of data and certainly needed to bring that into one spot so we could use it to manage better. This is not a land use plan. It is not with all the other government agencies. This is something the commission is doing and it is to better manage the oil and gas sector, so it is not a land use plan. We're just basically gathering all the data, all the provincial policy, any of the laws, the analyses that we've done. We've come up with this map and an associated report with it. Just so you see what's going on there, the red areas there are no-go areas, so the area around the lake there is a Class A park.

Some of the other red areas are as a result of some of the other pieces of legislation, whether those are riparian reserve zones or other wildlife habitat areas. Some of the areas around the river there actually were from input from First Nations and we're seeking more input from First Nations as we roll this out across the province. We started with this area in the Liard Basin, so that's the most northwesterly basin that we have, but now we are opening it up to the rest of the northeast. We were just going to move basin by basin, but as we started to move into one of the other basins, the guys just said, "Well, we don't we just do the whole thing because it's the same level of interpretation. We've got to gather all the data anyway; we might as well gather it once." So that is something that we're working on.

The yellow areas there are areas of best practice, so companies are allowed to apply in there, but there may be some specific practices that we expect, or First Nations expect or, in the case of the more southerly Montney play, than maybe some of the communities would expect.

So we look there, we develop as many best practices as we can. That yellow area is going to change for different issues, whether that is for values for moose or water, caribou or First Nations issues. Again, that's an Oil and Gas Commission-centric analysis tool. We take in as much information as we can, but it is for our decision-makers to make better decisions at the operational level, so we really do want to open this tactical conversation up more than just reacting to one permit at a time. Then the green area there is just to follow our robust law.

One of the other tactical tools that we developed and put in place in just the last year and a bit — so this didn't exist a little over a year ago — was our NorthEast Water Tool. Again, we had a lot of data and information that we wanted to bring together, make publicly available, again, for use by our staff, other government agency staff and the industry. So what we did is we pulled all that information together, worked with the Ministry of Environment, with the Ministry of Forests, Lands and Natural Resource Operations, and university researchers to bring all of the information together, whether that was individual data sources for water or whether it was modelling — whatever analysis was out there — and we came up with some management strategies for our statutory decision-makers.

This is on our website. It's managed by us with input from the other government agencies. We've modelled out water by watershed throughout the entire northeast. So you can go on there and you can click on any of the water permits or water licenses and see which company has authority for that water and how much they have authority to use throughout the entire northeast. Again, it's for us to use, companies to use, and it is publicly available so anyone can go and have a look at what we're doing in managing for water.

Just so you know, in terms of specifics about water use right now, again, the water use pattern has certainly changed in B.C. as we move to hydraulic fracturing, and that was a dramatic shift for us. Part of that was short-term water permits through the B.C. Oil and Gas Commission worked. It was for one individual well that was conventionally drilled. So the change to how we deal with water has gone on in the last five or six years. The water use patterns are dramatically different by basin as well, so it depends on what basin you are in.

In addition, we have enhanced our water-tracking procedures to respond to that change. We now report publicly on water use on a quarterly basis, and that is all up on our website. Of that 7.05 million cubic metres of water used for fracking, approximately 75 percent is from freshwater sources at this point, through water licences or short-term water permits. That accounts for a fraction of the percent of the mean annual water runoff in northeastern B.C. river basins for 2012, so we do that analysis as well.

Obviously protection of drinking water, protection of water quality, quantity and natural flow is important across the province. We have specific regulatory requirements that we can get into if you have questions on that. We use the best available input data research and analysis to make decisions on this. We track it internally so that we can see what the pattern is of water use by basin and by company. Certainly when we see that we had drought in 2010 and 2012, we anticipated that was going to be a problem, monitored it and our hydrologists then made recommendations to cease all water use under permit to us. So for those years, we shut down use for a number of months for the oil and gas companies.

As I said, we're trying to get as transparent on as many topics as we can, so if you go to our website, you're going to see an increasing amount of information on all the work we do on behalf of British Columbians. We want to be able to show them the information we use as part of decision-making as well as a summary of all activities that are going on in the province. One of the other sites that we developed as we saw what was going in other jurisdictions was called "FracFocus" and it's on www.fracfocus.ca. That's basically where we made the disclosure of hydraulic fracturing fluid components by well mandatory. We were the first jurisdiction in B.C. — sorry, in Canada — to do that. So right now you can go on that website and look up any company, any well, and you can see what hydraulic fracturing fluid they're using and how much they're using for that particular well. For us, that's just a first step. Now we're taking that information and we're certainly analyzing it and deciding what the next steps are. So we've tracked all this information. We have it and it's all publicly available.

One of the other things we did a couple of years ago is we worked with the University of British Columbia and we said we wanted to survey what British Columbians thought about hydrocarbon development in their province. So we worked with a professor that had done this type of work before. We asked a whole host of questions and it is on-line. The full survey is on-line and the analysis of it is on-line. It was all done through UBC. We looked at trade-offs and what people thought about trade-offs. One of the interesting things we did is ask, who do you trust? What is the trustworthiness? As you can see there, oddly enough, for the university study, the top trustworthiness group is a university. So you see the bottom end there, you see politicians and government officials and where people are actually trusting as well: experts, ENGOs, Internet and their friends and then all the way down.

We took that quite seriously. We took that information to heart and said, "Okay, well, how do we make sure that we are managing well on behalf of British Columbians?" So we went out and we started to work with universities in earnest. We had been obviously doing work with universities, but it was more ad hoc. So we reached out to UNBC and University of British Columbia. We had already done some work with UVic. We developed an ongoing partnership with them. We have some short-term studies with them and some long-term studies with them, but I think this is an important component of what we do.

Just in terms of some of the projects that we've got going on, some are of a technical nature — evaluation of gas migration in unconventional wells. That's important for looking at casings. It's important for looking at where gas is moving as a result of hydraulic fracturing.

Some of the other things that we looked at are induced seismicity. We have a three-year program with the university. They helped do peer review of some of the reports. Kevin will get into some of the induced seismicity issues that we've been dealing with. Air quality impacts — we are also working with universities on that as a result of natural gas development. That research, along with other information that we get and other data we get, is certainly informing the regulatory process that we have in B.C. That's been recent in the last couple of years as well, although we have done work, as I said, with universities on more of an ad hoc basis.

In terms of the expertise in-house at the OGC, we have every expert you would think we'd have for a single-window/full-cycle regulator: engineers, geologists, hydrologists, agrologists, biologists — every "-ologist" you would want.

Natural resource specialists — we have inspectors that go out there and do our inspections; we have First Nation and landowner liaisons, the odd lawyer and then our support groups. So we have a wide variety of expertise on staff and certainly they interact with each other on a regular basis.

In terms of monitoring hydraulic fracturing, as I said, we look to the water quality, quantity — we also look to soil. We are looking to impacts to soil and monitoring that. I mentioned induced seismicity that Kevin is going to get into in some detail. He is also going to talk about waste fluid injection and that is a big issue for the province as well. What do you do with this fluid once it's not used anymore? We obviously encourage companies to recycle, but just the scale of operations isn't allowing the level of recycling that I think we'll see when they've got more activity in the province.

Beyond the technical aspects that a company interacts with us on, we also are looking at the quality of life issues that are related to moving to hydraulic fracturing, or unconventional development. Some of those things are vehicle traffic — there is a lot more traffic for a given well pad now, there is a lot more potential noise on it for a longer term and visual effects are something that we're looking at as well.

So, we're using our experts — university researchers, input from area residents, local governments, First Nations and the industry and other government agencies to come up with what data we need to look at for that. We're looking to put some of this through our area-based analysis, so we can bring all that information into one spot and then really look at what quality of life benefits or values we should be looking at as part of the development of unconventional sources in B.C.

Again, I'm just going to get into some of the details of the basins — just a reminder of where they are in the province — in the northeast part there — and what they are. You can see that a lot of our activity right now — while we do have three basins in the very northern part of the province, most of the activity is occurring in the Montney down in the southern part of the northeast.

Certainly in that area we've got more residents, more First Nations communities and quite a bit of agricultural lands. So 73 percent of our activity right now is centred in the Montney and you can see the percentages for the other basins at this point. We don't see that changing over the next little while.

In terms of the geology, we have lots of geologists on staff and reservoir engineers who are constantly gathering all the information they possibly can from the industry as they prove out their resources, so we've got all sorts of subsurface mapping for all of the plays and all of the basins. What makes the Montney more attractive than the other basins is that there is a lot more liquids associated with the gas, so you can see we've got that mapped out there and that certainly makes it more economical during the low gas prices that we've been experiencing for the last little while. As well, there is less water needed in the Montney — and I'll show you that in a second — than in the northern basins. There is more infrastructure in place, so there are a lot more facilities and a lot more pipelines that are already in place in that area, so it just makes it more expensive in the other plays right now.

In terms of some of the parameters of some of the things that are of interest that we track and monitor, you can see the depth there for the Montney. There are different zones or plays that they're trying to hit, so anywhere from 1,800 metres from surface to 3,200 metres in depth. One of the big things we were seeing is that downward trend for $H_2S$ or hydrogen sulphide. There is a lot more in some of our conventional plays, and a lot less — dramatically less — in our unconventional plays. Then one of the other things that we're looking at is the amount of carbon dioxide, as you can see there.

For the most part it is less than one percent in the Montney, but we have seen it go up to five percent. In terms of what we are seeing in surface development, we are seeing upwards of 20 wells per pad. The well pads used to be 1.4 hectares in a conventional, so there was a single well that was 120 meters by 120 meters for the pad. As they have now moved to more wells on an individual pad, we have seen that go up to anywhere from 4.5, 5.5 or 6 hectares for an individual pad. Obviously they are accessing more gas through those individual well pads with more wells on that pad.

You can see that they are going up to 3,000 meters for a horizontal length, and then the average is around 1,600 meters. They are constantly pushing that out, so they are going to be accessing more and more of the resource from those individual well pads.

As I said, we are tracking the amount of water by fracture stage and by well, and Kevin will get into a little bit more of that. I am putting a lot on you so hopefully you are going to get into a little bit more of that.

In terms of the northern basins, the Liard, the Horn and the Cordova, there is not nearly the amount of activity in the Liard and the Cordova, and there is certainly a bit more in the Horn. But if you fly over the Horn River Basin right now, you will fly a long way where you don't see a lot of activity. It is clustered along a number of roadways throughout there. Certainly First Nations and other area residents use the basins, but they aren't permanent residents. Other than where you see Fort Nelson there, there is no real permanent residency throughout any of those northern basins.

For this area, we did a footprint analysis, just to see what the footprint of oil and gas is in that area. We did it for the full land and resource management plan area, so that does include all three of the basins. It is about 9,000,000 or 10,000,000 hectares of that part of the province. Of the footprint for oil and gas, about 1.5 percent of the area is currently taken up by pipelines, seismic areas, well pads and facilities.

Like I said, there's not as much activity up in that area, and we're moving to develop a footprint analysis for the entire northeast and so we're working on that now as well.

In terms of what the Horn River geology looks like — I thought I'd show a cartoon instead of just a table for this — you can see that the depth of the target formation there is approximately 2,000 metres — two kilometres — below the surface. This is a truer shale so it's a lot tighter than what's in the Montney, so you need more energy to actually fracture the rock. They're using a lot more water in the Horn River Basin that we've seen. Companies are coming up with water strategies in that area that are different from what is going on in the Montney. A couple of the companies got together and they developed the Debolt area where they're pulling saline water out. I think it's about 800 metres below the surface where they're pulling that out and they have a processing facility up in the Horn River Basin using Debolt water there so that they reduce their fresh water needs.

In terms of the carbon dioxide in the $H_2S$ — again, very low $H_2S$ up in the Horn River Basin, but what we've seen is a lot more carbon dioxide. This is a dry gas up in that area, so no liquids or minimal liquids. We're now analyzing what that carbon dioxide development means. What is that going to do for greenhouse gases in the area and how are companies responding to that. That's something we're analyzing and looking at as companies are getting going in that area.

Again, very similar to the Montney. We've seen quite a number of well pads with more than 16, but on average, there are 16 wells per pad, horizontal links very similar to the Montney — 3,100 metres was the longest we've seen with an average of 1,500 metres — and then again, all the water issues that we've looked at.

Our legislation — and I should have spelled that out — is the *Oil and Gas Activities Act* that guides and is our main piece of legislation, and then associated regulations with that. We do take policy from the other government agencies related to our mandate for oil and gas. Through the consultation process we get input from First Nations and others affected by activities. We have memorandums of understanding with I think pretty much every other government agency in B.C. We've got MOUs with NEB and Alberta Energy Regulator as well. We and our staff really do believe our commitment is to be a credible regulator on behalf of the entire province.

The act was enacted in 2010. We started looking at the development of the *Oil and Gas Activities Act* in about 2003-04. It took us a number of years to really do a fulsome consultation on that. It was passed in 2008 and then we spent from 2008 to 2010 working on the regulations and, again, seeking a lot of input into that. So it's a fairly modern legislative framework, and it was being developed at the same time that the province was moving from its conventional to unconventional, so we were able to pull in a lot of innovation as a result of looking at what other jurisdictions were doing — so very similar to what you're doing. Something that we would recommend is to really get a good handle on what your resource looks like and then build an updated legislative framework around that. We didn't do that on purpose. It just happened to shift as we were developing legislation, so it was lucky for the province that we were able to do that and have a modern piece of legislation that does respond to the unconventional approaches.

Part of it, interestingly enough, is that other government agencies can audit us in terms of our mandate in responding to environmental issues or how we are processing for natural gas as well.

That's built into the act itself. They haven't audited us yet, but we are looking forward to it if they want to. We have a lot of processes showing what we are doing, and we're not afraid to be held accountable to it.

In terms of the regulations underneath the act itself, there are two types of regulations. We have technical regulations that are actually developed by the commission through its board of directors. Then we have the Cabinet level or the Lieutenant Governor level regulations as well. The technical regulations that we oversee are the geophysical, drilling and production, pipeline and liquefied natural gas facility regulation, consultation and notification, and then the fee, levy and security, which is where we get our funding from.

In terms of the Cabinet regulations — what you would expect — so provincial regulations, whether that's the environmental protection, administrative penalties — a lot of those regulations are all set through Cabinet. That provides us with a little bit more nimbleness, I think, through the technical stuff to make some changes. Certainly with new legislation, we didn't expect that we would get 100 percent right. We're making changes right now, especially as the province is going through looking at liquefied natural gas. We're developing a liquefied natural gas regulation that's more accommodating for the larger facilities. We are looking at what consolidating of some of our other regulations into a hydraulic fracturing regulation would look like. Again, as we're going to go through discussions on what we're seeing in terms of induced seismicity or groundwater interaction, we maybe want to update that, so we're looking at that over the next year as well. That provides us the opportunity to continue to be nimble and continually improving.

Under the single-window approach, within the *Oil and Gas Activities Act*, we have specified authorities from other pieces of legislation that are actually embedded right in the middle of OGAA, so whether that's the *Land Act* — we have *Land Act* authorities for a variety of issues; we have *Water Act* authorities as well; we have the *Forest Act* and then a couple of others through the *Heritage Conservation Act* and *Environment Management Act*. So that provides us that single window as well as that full-life cycle approach and so I think that makes it a little easier on us and the other agencies.

Our goal, again, is to work with government, industry, First Nations, area residents and local governments in the development of the natural gas play up there. That is something that we take very seriously, and again, we'd be more than willing to hear from Yukon's experience as well, as you proceed. We'll take questions in a bit. I'll hand this over to Kevin once I get him set up here.

**Chair:** Thank you, Mr. Jeakins. Mr. Parsonage will have about 15 minutes.

**Mr. Parsonage:** Thank you for the opportunity to present. My presentation will focus a little more on the technical aspects of hydraulic fracturing and how we regulate and manage those and some of the issues that have arisen and how we've dealt with them.

The first step, really, is well construction. Having well integrity is key to ensuring that fracturing can be conducted safely. So this here is a picture of a typical wellbore. The first step is to install conductor casing — it's just a shallow casing at surface that prevents soil from sloughing into the hole during drilling and it also allows shallow gas flows to be managed safely. Following installation of the conductor casing, the surface hole is drilled, so that is drilled down below the base of any usable water for domestic purposes, and surface casing is set and cemented to surface. That allows all the shallow aquifers to be isolated from the well.

Following cementing of the surface casing, the surface casing is pressure tested and then drilling continues. Depending on the area being drilled, intermediate casing may or may not be installed. Essentially if there is a drilling hazard — such as high-pressure zones, low-pressure zones — that need to be isolated from the well to allow drilling, intermediate casing will be set. Regulations require that to be cemented at least 200 metres into the surface casing and then following that, the well will be drilled to total depth and production casing will be installed. Again, it must be cemented at least 200 metres into the previous casing string. So this leaves a continuous casing in cement from the depth of the well to surface.

Following that, we move on to completion operations, which with shale gas development typically involves hydraulic fracturing. So essentially what fracturing allows is the gas to get from the formation into the wellbore.

Here's a diagram of a typical well that you would see in B.C. Usually around 2,000 metres depth is the zone to be fractured and then there are multiple zones above that, including thick layers of ductile shales that prevent the fracture from migrating upward.

In B.C. most of our fracturing is very deep. We do have regulations that any fracturing above a depth of 600 metres must be specifically approved by permit, so this ensures that even though there isn't any shallow fracturing happening at this time, if there ever was, we would be able to assess the risk to groundwater at that time and ensure that it is done safely.

Materials involved in hydraulic fracturing: there is the base fluid, which in shale gas typically is water; the proppant, which is usually sand; fluid additives such as acid, scale inhibitors, friction-reduction, biocides, and then there is the pumping equipment at surface.

This here is a picture of a typical wellsite during a hydraulic fracturing operation. Just to put it into perspective, if this was a conventional well, there would be maybe about a quarter of the equipment that there is on-site here, so in the centre of this picture you can see the pumper trucks. Just to the right of that there are the sand trucks, the blenders, chemical injection, and to the right of that are the fluid storage tanks, and then just to the left of the pumper trucks in the middle of the picture you can see the wellhead with all the piping hooked up to it and then down in the bottom left-hand corner, the white and red vehicles are well test separators, so that's where when the fluid flows from the well, it goes through the test separator where gas, liquid, hydrocarbons and water are separated out. The liquids are sent to tank and then the gas is either flared or sent down the pipeline, if one is available.

So some of the challenges that we've experienced with hydraulic fracturing of shale gas: induced seismicity, as Paul has already mentioned; water management and specifically waste-water management; sand erosion during production of the well — this is erosion of the piping; interwellbore communication with fractures communicating with existing wells; and flaring and venting emissions.

So induced seismicity was first noted when some anomalous seismic events were noted on the NRCan regional seismic monitoring grid. Because there is some suspicion that it may be associated with oil and gas development, we initiated an extensive review and investigation to determine what was causing them and whether they were linked to oil and gas activity. So as a result of that investigation, it was found that the seismic activity was related to oil and gas activity. They are very small events. Only one of them was of a size that might have been felt at surface.

As a result of that, we've implemented a number of changes.

We've increased our ability to monitor seismic activity in the northeast by improving the monitoring grid. We have attempted to map areas that are at risk of induced seismicity. This is a specific type of faulting that puts an area at risk of seismic activity. Not every area is at risk.

We've added permit conditions to wells in the Horn River Basin, so that if seismic activity exceeds a tolerable threshold — which right now is set at four — then activity would need to be shut down. As part of the mapping exercise, we're avoiding placing water disposal wells in high-risk areas. The reason for this is because of the large volumes of water that can be injected through disposal wells. We don't want to be putting those into areas that are at risk.

Waste water management: obviously all the water that's injected underground over the life of a well, the majority of that water comes back to surface. When it comes back to surface, it's contaminated with whatever is in the formation, so typically salts and some hydrocarbons.

In B.C., we don't allow that water to be discharged to surface. It needs to be stored and then either reused or disposed into a disposal well. At this time, we have about 35 percent of the produced water recycled for other uses, and the remainder is disposed. Of course that requires storage of this water on the site, so we permit fracturing fluid storage sites. As you can see in this picture, those are a couple of lined excavations. We have a number of stringent conditions around how these sites are constructed and managed.

Some of the key aspects are: no hydrocarbons are allowed, only the water after the hydrocarbons have been separated; the sites must have dual synthetic liners with leak detection and with subdrains; and wildlife protection measures must be installed, so fencing to keep out big game and netting to prevent migratory birds from accessing these ponds.

So this is just a picture of a water disposal hub. One of the advantages with shale gas and multi-well pads is that now there is very predictable development, so this allows water pipelines to be laid and centralized water hubs, which improves the management of water.

Sand erosion is an issue that has arisen, because in some areas sand production occurs with the gas — not every area; it's more of an issue in the Montney than the Horn River. So this is a picture of a sand erosion failure of process piping at a site and basically what you can see is where the "T" comes off the bottom and a hole eroded in the piping. Because of this, we have implemented a requirement for sand management plans at production sites as part of the applications. This includes: de-sanding equipment to ensure that sand is reduced in the gas stream; piping configurations to reduce the number of bends that could be put at risk; leak detection; ultrasonic testing to monitor the pipe thickness; and velocity control to reduce abrasion from the sand.

**Chair:** Mr. Parsonage, I just want to remind you that we are at the five-minute mark and that the page will be collecting the questions.

**Mr. Parsonage:** I will try to move along quickly.

On to wellbore communication — this is where fracture operation communicates with another well — whether it is a drilling well or producing well. In B.C., the shale gas areas don't have very many legacy wells, so we haven't had any issues with communication with old wells as has happened in Alberta. The primary issue has been drilling and fracturing in close proximity causing drilling kicks. A secondary issue has been disruption of production from producing wells.

As a result of this, we issued a safety advisory reminding companies to ensure that they monitor the wells in the area of hydraulic fracturing events and ensure that they are managed safely. We also participate in the hydraulic fracturing industry recommended practice and since we have issued this advisory, we haven't really had any issues.

Finally, flaring and venting. There have been several studies, some of which suggest that methane emissions as a result of hydraulic fracturing are quite significant. If you look at the diagram in the top right corner, that was essentially predicated on the assumption that the gas flow from the well is directed to open tanks and pits and the methane is vented. That is something that has never been permitted in B.C. There has always been a requirement to at least flare the gas at a minimum.

So what you see in B.C. is that the gas goes through a three-phase separator. The liquids are separated out and then the gas is either flared or sent to gas sales. With shale gas development, now that we have multiple wells on a pad and the success rate of the wells is much higher than conventional gas, it allows pipelines to be constructed prior to drilling.

Because of that, it has increased gas recovery during cleanup and well testing, instead of flaring. So in 2006, when the activity was generally conventional, there was essentially none. We actually had a requirement for a well to be proven before a pipeline could be constructed and now — with hydraulic fracturing and shale gas development — in about 75 percent of our wells, the gas is recovered instead of flared. As development continues, we expect this to increase.

Finally, fugitive emissions management: every well and facility in B.C. is required to have a fugitive emissions management program by regulation. The baseline standard is to follow the CAPP best management practice for fugitive emissions.

Finally, compliance and enforcement: we do have a robust compliance and enforcement program. There is a risk-based inspection module, computer modelling and we also respond to public requests, complaints and reported incidents.

The inspection process — first we identify inspections, prioritize them and plan them. The results of the inspections are communicated to the operator. Then a follow-up period occurs, and then finally, if there's no action, then we proceed with enforcement. That's all I have, thank you very much.

**Chair:** Thank you, Mr. Parsonage. The Committee will be taking a short recess and reconvene at 11:30 a.m. so we can proceed to questions. All the written questions from the public gallery should be with the page at this time. Thank you.

*Recess*

**Chair:** Order please. We're going to resume with our round of questions. Our first questioner will be Ms. Moorcroft.

**Ms. Moorcroft:** Thank you Mr. Jeakins and Mr. Parsonage for your presentation.

My questions are about water. One source of water for the industry is a groundwater pit created by digging a trench down to the water table and then using that water for hydraulic fracturing.

Can you confirm whether the use of groundwater pits as a source of frackwater is measured and captured in the regulatory regime? What percentage or total volume of the water used by industry in hydraulic fracturing comes from groundwater pits?

**Chair:** If you could just indicate to me who is going to be speaking, then I can get your mic turned on.

**Mr. Jeakins:** I'll start and sometimes I might have to throw it over to Kevin. So just to clarify, when you mean a groundwater pit — groundwater for us is subsurface water whereas there is surface water that may flow into a pit that's developed. Is that what you mean — not accessing the groundwater specifically?

**Ms. Moorcroft:** A pit that is created by digging a trench down to the water table and then gathering water and using it.

**Mr. Jeakins:** So right now, companies and even landowners are digging pits to capture fresh water and are using that for hydraulic fracturing. In terms of the regulations of those, we at the commission have started to issue short-term water permits for those, and that might be pushing the regulatory envelope a little bit but we thought it was important to gain a little more perspective on how those are being used and monitored. They're not specifically permitted under the *Water Act* as it sits right now, but we thought it was important that we do monitor them, so we do issue permitting for that and we do track them. We don't track all of them on private land, but certainly for the oil and gas companies we do.

**Ms. Moorcroft:** The question that I'm interested in is: How much of the water used by industry — whether in volume or percentage — is tracked from those short-term water permits, and are short-term water permits issued in all cases?

**Mr. Parsonage:** All the water permits that the commission issues — the water use is tracked. I think maybe one quick clarification on the pits that are dug is that they're not dug to intercept groundwater, so they fill with surface water from runoff from rainwater.

**Ms. Moorcroft:** What quantity limits, if any, are placed on frack-related water withdrawals in the Horn River Basin area? Are there any instances where companies have been ordered to stop water withdrawals?

**Mr. Jeakins:** So as I said — answering your second question first — stop water withdrawals during the droughts of 2010 and 2012 — we certainly issued a stop order to utilize water from a number of the sub-basins that we monitor.

As far as the Horn River Basin specifically, there's not that much activity right now in comparison to what we think is going to happen over the next four years. The amount of water that people are applying for has been reasonable in our estimation anyway, based on our analysis.

**Chair:** Ms. Moorcroft, you have 30 seconds.

**Ms. Moorcroft:** So you're saying that's a reasonable amount of water given your analysis. Do you have data on the total volumes?

**Mr. Jeakins:** Yes. As I said, our NorthEast Water Tool tracks as much information as we can possibly gather for that part of the province and certainly tracks all of that by basin that we've analyzed and even in the individual water courses — whether it's a lake, a stream or a river. So as much as we have all of that data, we utilize it and certainly our staff is monitoring that constantly.

**Mr. Silver:** Thank you, Madam Chair, and thank you gentlemen for your presentations here today.

You mentioned in your presentation area-based analysis for the Liard play. Define the process for developing restricted and no-development areas and your consultation process to develop these areas. Specifically to your more remote northern plays — the Liard, the Cordova and the Horn River Basin — could you speak toward social licence and/or litigation? Has your province experienced much opposition to the dramatic shift to unconventional resource extraction?

**Mr. Jeakins:** Sure, that's a lot of questions. I'll have to write some of them down and I might miss them, so you might have to capture them again.

As far as the area-based analysis approach goes, in terms of setting up the no-go areas and even the best practices areas, our first step was to utilize the legislation and the policies that were in place in the province. As I said, that big red area around the lake was already a class A park, so that was easy. Some of the riparian reserve zones came out of the environmental protection and management regulation that we developed as part of the *Oil and Gas Activities Act*. Some of the other areas — wildlife habitat areas — some of the other agencies will put on. We just accept those as — they flow under the *Oil and Gas Activities Act*. But there are other things that we're considering and we want to expand beyond just the policy and legislation into input, whether it's from First Nations or area residents or other policies that aren't enshrined in legislation at this point, whether it's caribou management, or spiritual or cultural areas, or anything First Nations might consider important that we have to consider.

That's the next step where we are going right now in terms of the consultation process. We worked a lot in-house just to kind of work it through, because a lot of the information already exists and this was going to be used by the B.C. Oil and Gas Commission. It wasn't going to be an external land use planning approach. That's something we started with. We worked with companies initially to try to get them onboard to see if they wanted to participate or not. We've just finished going to all of the First Nation communities in the northeast and asking whether they want to participate or not. We have some uptake and some don't want uptake on that process. What I say to either industry or First Nations or area residents is that it's only going to be a better process if they do participate, but they don't have to. It's not mandated. It's not land use planning.

The other thing B.C. is looking at is a cumulative effects approach. What I've said is that if the larger government is going to go that direction, then we'll just feed our information into that. We're leading now because we think we have the opportunity to do that. As I said, we're a little more nimble and we can move a little quicker, but if government is going to take on a broader cumulative effects approach, then we'll just fit right underneath that. I've made sure government, First Nations and industry know, that that's how we are going to do it.

In terms of litigation, we've had a bit of litigation — not dramatic. So when you ask about opposition, sure there has been opposition, whether it's through judicial review or appeals through the commission. Certainly there is opposition. It's not everybody agreeing on whether it should be done or how to do it. That's something certainly that we have to take into account. We have one thing before the courts right now in terms of issuing water permits and how that goes. Ecojustice is pursuing that through the courts right now.

It is mostly about process, but what we really want to look at is, is the water available to actually give a permit or a licence as part of it, so we are working through it right now. If litigation changes how we do things, then we change how we do things. We would rather take it as input and not get to that stage, but we have no problem changing if we need to change.

**Hon. Mr. Dixon:** How do you calculate and collect royalties for the resource and what is the value of those royalties to the province?

**Mr. Jeakins:** That is a good question. Fortunately or unfortunately, we don't deal with the royalty aspect; that is through the Ministry of Natural Gas Development, so I would rather not get into how the province deals with that. That is one of the benefits of being a separate regulator: we don't look to encourage the increase in activity that the ministry does. The B.C. Oil and Gas Commission strictly deals with the regulatory aspects.

**Hon. Mr. Dixon:** What testing requirements do you provide to demonstrate the ongoing integrity of well casing and the wellbore?

**Mr. Parsonage:** Following drilling, all the casing and cementing and drilling information is submitted to the commission and, at that time, it is reviewed by the commission engineers. If there are any issues identified, they are followed up on, and if there are any repairs that are required, they are required at that time. At the time of well completion, those plans are submitted to the commission and reviewed by the engineering group, and then the well is put on production.

When the well is on production, if there are no obvious problems that appear, then generally no additional tests are required, unless it's a specific — so some of the high-risk wells, such as injection disposal wells and wells with very high $H_2S$, there are additional monitoring requirements. Then when the well is taken off production, there are additional testing requirements at the time of well suspension and again at the time of well abandonment to ensure that it's properly abandoned. That involves looking at the casing and cementing and doing any remedial work that's necessary.

**Hon. Mr. Dixon:** How often are abandoned wells monitored or tested?

**Mr. Parsonage:** They're monitored through our inspection program. Of course, we have thousands of wells, so we have a database and risk-ranking criteria. Based on the risk of the well and also the time since the last inspection, then every quarter it provides a list of wells, including abandoned wells. Then our inspectors go out and check them out and ensure that they're still safe. So it's, I guess, a percentage of the wells every year.

**Hon. Mr. Dixon:** That's it for me, Madam Chair.

**Mr. Tredger:** Welcome to the Legislature to our guests and thank you to the people of Yukon for listening in.

We've learned that fracking impacts air quality in many different ways, but of particular concern is flaring, sometimes venting, and often during completion of a well, incineration. It's particularly the completion phase, that three or four days of intense burning or flaring. I realize that flaring is not the best practice and it decreased; however in Alberta, it's increasing again.

My question is, what air-quality monitoring is being carried out on-site and near fracking operations and how is this data shared with scientists and First Nations and the public, and what percentage of wells are actually monitored for air quality?

**Mr. Parsonage:** I guess there are a variety of processes that we undertake. First of all, I'd just like to — in Alberta, the big increase in flaring is actually associated with heavy oil development, not with natural gas — that is why they've had a big increase in venting, particularly — gas associated with oil production.

We have a variety of criteria. Of course the first one is that we require the gas to be flared and not vented, so that we minimize the emissions. Obviously flaring isn't desirable, so as I pointed out in my presentation, as much as possible, we try to conserve that gas through pipelines. Of course that is difficult to do in the early stages because you don't have the infrastructure and the processing plants in place. You need a minimum number of wells in order to develop and use that infrastructure.

In terms of air-quality monitoring, we have different processes, depending on the hydrogen sulphide content of the gas. If it's over one percent, we require dispersion modelling to be conducted and then, depending on that dispersion modelling, we may require real-time modelling. During the flaring, we may require air-quality monitors to be placed in areas that are identified as at-risk. Then in addition to that we also have a mobile air-quality monitoring unit that we've just acquired in the last few months, so we're starting to deploy that out. We also have infrared cameras that we can use to detect methane emissions. Again, we just acquired those in the last few months and we're just starting to use those.

**Mr. Tredger:** So what percentage of the wells would actually be inspected then, monitored for air quality?

**Mr. Parsonage:** As far as during flaring?

**Some Hon. Member:** (inaudible)

**Mr. Parsonage:** For shale gas wells, they're typically not monitored because they have very low $H_2S$. So where you'd see more monitoring is actually in the conventional wells with higher $H_2S$.

**Mr. Tredger:** I've had concern expressed about volatile organic chemicals, especially in the initial phase of completion, when they're burning off some of the produced water, as well as the gas that is incinerated.

In terms of wellbore integrity, how long has that monitoring been going on? Are the results available to the public? In terms of the integrity of the well, or the safety of the well, how many of the wells are non-compliant or of concern? What percentage would that be?

**Mr. Parsonage:** I am not sure if I quite follow the question. In terms of non-compliant wells, of course we review each well after drilling, so if there are any issues where we're concerned about the cementing — if we are concerned that cementing wasn't successful — we deal with it at that time. I don't think I can give you an exact percentage, but it would be fairly low. Maybe a few percent of wells require some sort of remediation.

In terms of the data being available, all of our well files are publicly available. There is an initial confidentiality period to protect companies' commercial interests, which ranges from about three months to two years, depending on whether a well is in development or exploratory, but after that time, all the data is publicly available for anyone who cares to look at it.

**Mr. Elias:** Thank you gentlemen for your time here today. I did have a couple of questions. One is with regard to section 51 of your drilling and production regulations about how you contain and isolate fluids, but you answered those in your presentation, so I only have one question.

Some regulators have said to us that they didn't foresee this exponential growth of hydraulic fracturing stimulation with regard to oil and gas development and they gave us some recommendations, some to do ASAP and some to follow through with, whether regulatory or environmental monitoring and such.

In the Yukon, water is extremely important to our citizens, thus is represented in constitutionally entrenched land claims under chapter 14, which guarantees First Nations the rights to have their water unaltered in terms of quality, quantity and rate of flow. We have a Water Board that is quasi-judicial and has the right and responsibilities to issue water licences under the *Waters Act.*

We have the Yukon Environmental and Socio-economic Assessment Board and act that use water as a valued component when making its recommendations to the decision bodies. We have seven Yukon government departments that have responsibilities with regard to water. We have the federal government and Fisheries and Oceans and Transport Canada, the Department of Aboriginal Affairs and Northern Development. We have the Yukon *Oil and Gas Act* with the Oil and Gas Resources branch and Yukon First Nations rights that protect water on or adjacent to settlement lands. Those rights are guaranteed under the constitution of our country. We have our municipalities and boards and committees, renewable resources councils — the list goes on and on. All of these water responsibilities in our territory don't exist anywhere else in Canada. That's how important water is to our territory's citizens.

I guess my question to you is: what recommendations — short-term, medium-term and long-term — would you give our territory, should we decide to regulate hydraulic fracture stimulation in our territory?

**Mr. Jeakins:** That's a big question. We probably don't have enough time to get into the full meat of it. As I said, the development of a solid regulatory framework was really important to British Columbia. We had that opportunity just as we were shifting from conventional to unconventional. So taking the time and getting as much input as you can into the development of that framework, I think, was critical for us. I would recommend that to anybody as they get going on this. When Quebec came to us and we were talking about what they were going to do, we were fully supportive of them to not have a whole lot of action until they develop their own regulatory framework that was specific to their area. I mean the geology across Canada is different for every shale play — or unconventional play. You really have to look at what your resource is looking like as well. And you have to make the decision: do you want to actually have any freshwater removals or groundwater removals?

If yes, you're going to do that, then there are a lot of checks and balances you can put in place. A lot of it is data gathering — getting the information ahead of time — similar to what we were trying to do with the NorthEast Water Tool coming up with all the information we could possibly gather. We wanted it peer reviewed. It wasn't just our decision and just the other government agencies. We worked across agencies. We worked with many university experts. I think we had four or five different university experts working with us on the development of not just the data gathering but also the modelling. That's a lot of groups you've got working on water. It is important. It's critical, I think, everywhere you go.

For us, I think the coordination of it also is important, so that you're not having different groups running off in different directions with different either philosophical or target mandates. I think that's been important as well — monitoring it all. One of the things we did in the northeast as we were developing the tool just for the oil and gas sector is when we worked with the other agencies — is determining that it's probably a better management tool to work across all licensing and permitting for whatever sector — whether it was mining or forestry or whoever else was using water — and to, again, consolidate that so we're working together. I think people think we're doing that inevitably anyway, but this was the first time we actually pulled it together because activity was increasing, as you're seeing in Alberta where they're saying to get out ahead of this.

I think we did a lot of thinking about that. As I said, we went to other jurisdictions to really see what was going on in anticipation of that shift, and I think that B.C. has responded really well in terms of both its legislation and its processes and its data gathering. We're still catching up in some cases, but like I said, we're continually improving where we can. That's the short answer, but there is a much longer answer there.

**Chair:** Thank you. I don't have any particular questions other than those my colleagues have already asked. We would like to get to our public questions, so Ms. Moorcroft will start with the first question.

**Ms. Moorcroft:** The first question is from Wilf Carter of Whitehorse. How much water is used to drill wells compared to other water users, such as a community?

**Mr. Parsonage:** I couldn't provide any specific numbers off the top of my head. Overall, we do have a water report on our website and it shows total water use by the oil and gas industry.

**Mr. Jeakins:** I guess what I would say is that in our initial water report that we put out a couple of years ago, we did a comparison just to see what it looked like in terms of domestic use or other recreational uses. I don't really want to get into that comparison. I think what we've got to do is look at what water — freshwater, groundwater — use is appropriate overall. Rather than compare one to the other, I didn't really want to continue looking at — "Jeez, we're better than the city of —" — I didn't think that was useful in the conversation. So that's why I'm saying that you've got to get the broader picture of water management and really understand what's available, and how much you should permit and how much you shouldn't.

**Mr. Silver:** Thank you, Madam Chair. This question comes from Peter Percival from the Hamlet of Mount Lorne. Can you describe the construction and operation of salt bed cavern oil and gas storage structures? Are there salt beds within Yukon oil and gas basins that could be utilized for the development of these storage structures?

**Mr. Parsonage:** Typically a salt cavern is constructed by drilling down and essentially dissolving the salt to create a cavern. I don't know about the Yukon, but we don't have any cavern storage in B.C. I believe there are some in Alberta and Saskatchewan. B.C. has one gas storage site that's essentially a very highly permeable conventional formation.

**Hon. Mr. Dixon:** This question is from Laura Spicer, who is with the Yukon government Oil and Gas Resources branch. Mr. Jeakins, please comment on when it is an advantage to use goal-oriented regulation versus prescriptive regulation?

**Mr. Jeakins:** That's actually a really good question and something that we are looking at right now. We're looking at what is that appropriate blend between prescriptive and results bases — how we characterize it and then how do we use professional alliance in all of that?

One of the things — we've been talking about this with liquefied natural gas specifically — is we're updating that particular regulation and looking at a professional alliance model. What we said is that there are certain things we're just not going to sacrifice — that the government should always look at. So those are going to be safety issues or any of the critical environmental issues. I can't give you a percentage on that. It's more the things we want to make sure that government has some oversight on.

Some of the other things where they're very technical, very detailed issues that are being dealt with by experts and that are engineering-specific, then we probably would go to a professional alliance model on that.

It really is topic-specific rather than percentage-specific, so we have a blend in our legislation. Some is prescriptive and some is results-based.

**Mr. Tredger:** This question is from Jannik Schon of Whitehorse. What is the average lifespan of a well in the Horn River Basin? How many new wells are drilled each year?

**Mr. Parsonage:** I guess we're not entirely sure exactly what the lifespan of a shale gas well will be, but likely in the range of 30 years or so. Right now I believe there are only about 30 or 40 wells a year being drilled in the Horn River Basin. Essentially that's because the gas prices are so low right now.

**Mr. Elias:** This question is from Katherine Tragan: After the well is abandoned, how will wells be monitored and regulated, and who will be responsible in the future?

**Mr. Parsonage:** As I mentioned before, we do have an inspection program that also covers abandoned wells, so we do regularly inspect them. In the event that there is a problem identified with an abandoned well — it does happen from time to time now — then we go back to the company that is responsible for the well and have them go in, repair the well and do whatever is necessary to bring it up to standard. In the event that we can't find a responsible operator, then we have an orphan well fund, which is funded by industry, that the commission administers, and then we would take over responsibility for the well and ensure that it is brought up to standard.

**Chair:** I have a question from Sally Wright. How can you say you were nimble when it appears northeast B.C. has been overwhelmed with development? How could you possibly keep up with this?

**Mr. Jeakins:** Again, it's a scale thing. So, as Kevin said, we've got a number of wells — I think we have 29,000 wells in B.C. drilled since the 1950s. The activity levels haven't been as prolific as some of the other areas. Alberta has upwards of 400,000 wells — granted our wells are all concentrated mostly in the northeast of the province.

I think we have done a reasonable job of being ahead of what that could look like in terms of our legislation and in terms of our ability to have staff deal with all of the issues that are going on there. We are not perfect in how we are doing this, and we are certainly bringing together expertise from a number of other agencies in order to anticipate all of the issues there.

The nimbleness for us is just having that level of expertise in-house and the ability to look at an issue from a fairly holistic approach — plus our funding model is not through Treasury Board, so it makes it a little bit more nimble in terms of continuing to develop our programs and develop our staff. We are not perfect, but we are hopefully getting there.

**Ms. Moorcroft:** The next question is from Josh Barichello of Ross River: Has an earthquake study been initiated in the Horn River Basin? If not, what is the reason for the delay?

**Mr. Parsonage:** Yes, we did do a study on induced seismicity, which was released and is on our website. I touched on it in my presentation, and the full report is available for anyone who is interested to have a look at.

**Mr. Jeakins:** Just to add to that, when we began the study we also wanted longer term research as well, so we initiated a larger induced seismicity study with the University of B.C. They did a peer review working with us and the federal government in terms of our report that is on-line, as Kevin said, and then we have a longer term study going on in induced seismicity with the university as well. So, if we miss something, we want to see that knowledge gap filled.

**Mr. Silver:** This question is from an anonymous member of our gallery today. Why were aquifers not mapped proactively in the Horn and Montney basins? How does this lack of information impact ability of regulators to regulate?

**Mr. Jeakins:** I'll flip it over to Kevin.

In B.C. we haven't mapped all of the aquifers and it is a gap that we're attempting to fill. I believe Geoscience BC has done some work in the Horn River so that they are mapping the aquifers. I think that study might have just come out recently, but it is a gap and certainly something that we want to fill over the next little while. I don't know if you want to get into the specifics of groundwater use, drilling —

**Hon. Mr. Dixon:** This question is from Susan Gwynne-Timothy from Marsh Lake. Why no mention of air quality in a chart titled "Monitoring Hydraulic Fracturing"? Dr. Theo Colborn, in Colorado, has done lots of work on native volatile gases released from shale that cause asthma, brain damage and eventually cancer, with long-term, low-level, chronic exposure — for example, benzene. What are the public health costs of these? Are you going to measure this and compare the income of the government with the cost to the government of increased illness?

**Mr. Jeakins:** I think in one of the slides I showed that we are monitoring air quality. I think Kevin talked about the new equipment that we have purchased recently to make sure that we are looking at that. It is a serious issue and we want to expand our air-quality monitoring program, working with the Ministry of Environment, which is also developing a bigger air-quality monitoring program there. Certainly the health departments up in the northeast are making us aware of all the issues that need to be looked at, and we are starting to work with them as well. I don't know if there's anything else you want to —

**Mr. Parsonage:** I guess just specific to benzene emissions, the major source of benzene emissions is glycol dehydrators. That is a piece of equipment that removes the water from the gas stream. This is something that — whether it's conventional or unconventional gas — it's gas processing, so it's the same either way.

A number of years ago we participated in a group with Health Canada and the other provincial regulators to work on a program to reduce benzene emissions. It has been very successful; it had something in the range of 90-percent reduction in benzene emissions. This is through better control of the dehydrators and through flaring or incineration of the off-gas.

**Mr. Tredger:** This question is from Bob Truelson. The previous speaker, a B.C. hydrogeologist, mentioned that the commission was not collecting information on long-term wellbore integrity as recent as two years ago. Has this changed and have stakeholders been satisfied?

**Mr. Parsonage:** I'm not entirely sure in terms of what he means by "collecting information on long-term wellbore integrity". We do have very robust requirements for wellbore suspension and abandonment to make sure that, when a well is at the end of its life, it is managed appropriately. That is an ongoing program for a number of years. Nothing has really changed recently with that. And then, as I mentioned before, we also do have our regular inspections.

**Mr. Elias:** This question is from Michel Dufeau. What are the reasons why British Columbia does not require recycling of fracking water as well as treatment before its disposal?

**Mr. Parsonage:** We do encourage recycling where it is possible, so about 35 percent of the water is recycled now. It gets to a point where it has too many contaminants in it to allow it to be reused again. In terms of treatment before disposal, because we don't allow any surface discharge, it all has to — deep-well disposal is the only permitted disposal method. Really there is no need to treat it because the water is going back into saline aquifers or into depleted oil and gas reservoirs.

**Chair:** I have a question from Rob Lewis. What measures are in place now to deal with and pay for wellbore integrity failure 10, 15, 20 or more years from now?

**Mr. Parsonage:** Yes, as I previously mentioned, after a well has been abandoned, the company is still responsible for it, so if there are any issues with wellbore integrity, they have to go back and do the work and, in the rare case where we can't identify a responsible party, then we have an orphan well fund funded by industry levy that the commission administers to take care of those issues.

**Ms. Moorcroft:** The question is from Don Roberts.

How many inspectors are there in B.C. to monitor the oil and gas industry and approximately how many inspections were performed in 2013? How many wells were inspected? How many wells are there? How can the number of inspectors adequately monitor with integrity water use, water contamination and abandoned wells?

**Mr. Jeakins:** Those are a lot of questions. Hopefully I'll get them all.

We have 15 or 16 inspectors in our offices. Kevin's group provides some technical expertise and they also do some inspections. Our inspectors do, I believe, 4,500 to 5,000 inspections a year. That's our target. We've been able to do that every year.

In terms of keeping up with all the program, again, as Kevin pointed out, we do risk modelling in terms of the highest-risk areas. Certainly we want to expand that to make sure that we're covering off as many sites as we can. One of the other things that B.C. is looking into is moving into more of an audit program as well, so using inspections as well as full-blown audits to supplement some of our normal day-to-day inspections.

In terms of the numbers — I can't remember what the last question was.

**Ms. Moorcroft:** How many wells?

**Mr. Jeakins:** How many wells get inspected a year? I'm not sure out of the 5,000 how many wells we specifically say, but we do our compliance inspection report on-line as well. Unfortunately, I can't answer that one right now.

**Ms. Moorcroft:** You said that you inspected about 5,000 wells and the question was how many wells are there?

**Mr. Jeakins:** The 5,000 inspections are of everything, so that would be wells, facilities and pipelines.

In terms of the number of wells, I think we have 29,000 or 30,000 in B.C. right now. That includes active and abandoned. It's not just active wells.

**Mr. Silver:** This question is from Sandy Johnston. What is your role in assessing the cumulative greenhouse gas emissions from proposed and existing operations to ensure greenhouse gas reduction targets will be met?

**Mr. Jeakins:** In terms of greenhouse gases right now, that is largely dealt with through the Minister of Environment. We do permitting for some of the air quality issues, but in terms of greenhouse gases, that is monitored by the Minister of Environment. We will work with them on issues related to oil and gas, but they are the lead.

**Hon. Mr. Dixon:** This question is from Rick Griffiths of Whitehorse: What water baseline studies were done in any of the basins before hydraulic fracturing began? How can you be sure about the ramifications of fracking on surface and groundwater, including removal of water from rivers, impacts of migration fluids from fracking on groundwater and the disposal of produced water if there were no baseline studies before the hydraulic fracturing began?

**Mr. Jeakins:** B.C. had a lot of data and we do have a lot of data on our environmental values in the province so the NorthEast Water Tool was meant to bring all that together. So that didn't exist prior to hydraulic fracturing starting, but again it hadn't started in earnest before we got the NorthEast Water Tool there. We didn't have the data housed in one spot but certainly the information was there to make decisions and our experts within the OGC certainly used the data as it was there.

But it wasn't to the level that we are using NEWT now. As things get going, we want to make sure we are proactively ahead of any increase in hydraulic fracturing or any development in natural gas.

**Mr. Tredger:** This question is from Davina Harker. In areas of heavy fracking, what health issues are you having to mitigate and/or monitor? Can you list current concerns?

**Chair:** This will be our last question.

**Mr. Jeakins:** Unfortunately I'm not going to be able to answer to the level probably that it needs. We don't monitor health affects directly at the OGC. Again we work with the health authorities up there. There have been a number of studies that we will access, but the health authority is the lead on that.

**Chair:** The time for questions has now elapsed, and I want to thank Mr. Jeakins and Mr. Parsonage. Thanks to all the visitors in the gallery who submitted questions. Committee will review the remaining questions that we have from the gallery and do our best to follow up and ensure that they are answered.

We are going to break for lunch now. The next presentations will be at 1:15.

*Recess*

**Chair:** I want to welcome everyone back to the proceedings of the Yukon Legislative Assembly's Select Committee Regarding the Risks and Benefits of Hydraulic Fracturing.

For those joining us for this presentation, allow me to introduce the members of the Committee. I am Patti McLeod, the Chair of the Committee and member of the Legislative Assembly for Watson Lake. To my left is Lois Moorcroft, who is the Committee's Vice-Chair and the Member for Copperbelt South. To Ms. Moorcroft's left is Sandy Silver, the Member for Klondike. Behind me is Darius Elias, the Member for Vuntut Gwitchin. To Mr. Elias' left is Jim Tredger, the Member for Mayo-Tatchun, and to Mr. Tredger's left is the Hon. Currie Dixon, the Member for Copperbelt North and Minister of Environment, Minister of Economic Development and the Public Service Commission.

This Committee's mandate is set out in Motion No. 433, which specifies that the Committee is to develop a science-based understanding of hydraulic fracturing and also allow for an informed public dialogue. To this end, we shall hear several presentations over the next two days concerning both the potential risks and benefits of hydraulic fracturing.

I would like to welcome the visitors in the public gallery and our next presenter Adam Goehner. Mr. Goehner is a senior advisor and environmental engineer with the Pembina Institute, an organization that advocates for the protection of Canada's environment.

Following Mr. Goehner's presentation, we will take a short recess before proceeding with questions. If visitors in the gallery would like to submit questions, forms and pencils are available at the entrance to the gallery. The page will collect the written question forms at the end of the presentations — more accurately, about five minutes before the end of the presentations.

After asking a few questions each, members of our Committee will randomly select written questions from those that have been submitted by visitors in the gallery. Time, of course, will not guarantee all public questions will be asked and answered, but we will do our very best with the time allotted. I would ask that questions and answers be kept brief and to the point so that we may deal with as many as possible.

Please note that the proceedings are being recorded and transcribed. If your question is selected, the information you fill out on the form may be read into the public record.

I'd like to remind all Committee members and Mr. Goehner to wait until they are recognized by the Chair before speaking so that microphones can be turned on. I would also ask that visitors in the gallery respect the rules of the Legislative Assembly. Visitors are not allowed to disrupt or interfere in the proceedings. Please refrain from making noise, including comments and applause, and mute any electronic devices. We will now proceed with Mr. Goehner's presentation.

**Mr. Goehner:** Thank you for inviting me to present today and to speak about the environmental impacts of unconventional oil and gas development.

Just a brief background of myself: I'm currently a senior advisor with the Pembina Institute. I work on the unconventional oil and gas issues primarily in Alberta, British Columbia, and the Northwest Territories. Prior to joining the Pembina Institute, I worked as an engineer in the oil and gas industry for a few of the major oil and gas companies in Canada.

As another introduction to the Pembina Institute, we're a non-profit think-tank with about 50 staff across Canada. We have worked in a number of areas and we work to advance Canada's transition to a clean energy economy. We do that through research, education, consulting and advocacy work, so we have a number of different areas in which we engage.

In terms of our recent publications, we have a number of different reports and research that we have released to date on this issue — relating to this issue. We have looked at shale gas impacts to climate and water in British Columbia. We have done projects Canada-wide looking at natural gas as a climate solution, and in other areas we have brought stakeholder groups together to have thought leaders' forums specifically addressing the impacts associated with shale gas. All this is available on our website and I'm bringing a lot of information from these reports into the presentation today.

To get started on some overarching headlines and recommendations, the regulation and robust regulation is challenging. It is no question that there is a lot involved. The rapid technology change provides complexity and makes creating regulation a challenge. There are significant gaps in the knowledge currently, and the information is evolving as we go forward.

It's important to have regional planning and land use strategies in place prior to approving significant development if we're to affect some measurable decreases in the environmental impact associated with this. That's a challenge because we don't always have all the information prior to making those types of plans and strategies before the industry moves in to develop a resource.

Some key elements that should be included are: regulation should be adaptable to a changing understanding, and as knowledge evolves and progresses, it needs to be able to include that and change resulting from that increased understanding; it should also be adaptable to an evolving pace and scale of development, so if things ramp up or slow down, depending on different external factors, the regulations should be able to adapt to that and react accordingly.

Cumulative impacts for water and land are a big consideration to look at. What that means is we need to have thresholds and limits in place, proactive regional water sourcing, and waste management and land use planning. I'm going to touch on all of these in greater detail later on in the presentation as well.

Greenhouse gases, venting and flaring — this is another area of concern that not only extends to the local region but extends globally as well, and, for this, limits are essential and continuous improvement should be encouraged.

Data transparency — in order to keep progressing on these issues and have enough informed dialogue about this, there needs to be a level of transparency in the data and there should be independence in the data as well so it's not just coming from one source. This enables us to benchmark and evaluate the performance that is going on.

Lastly, considering legacy issues — what's remaining after this development takes place and what mechanisms need to be in place so that it reduces the long-term liability that is left over for the public to deal with after the primary extraction has taken place.

So, to start off, I will just start with a couple definitions so that we can talk about some of the terms that I will refer to later on in the presentation.

First off are ecological thresholds. This is the point where small changes in a certain condition can cause rapid changes to the entire ecosystem. When an ecological threshold is passed, the ecosystem may no longer be able to return to its previous state or to the state of predevelopment. That's a significant concern, especially to habitat and wildlife, but also to water and the broader ecosystem that supports.

Cumulative effects — when we talk about cumulative effects, that's when there are many repeated actions on a certain ecosystem and the effect of those repeated actions is greater than their individual effects. If we're looking at small projects by themselves, they may not have the type of impact that we would see if we look at all the projects over top of each other and all the different types of impacts that are going on on that land base. So it's not just oil and gas activity, but other impacts from other industries or uses as well.

Briefly, I'll just go over this. These are the kinds of different impacts that I'll try to touch on today and provide an introduction to. I'll talk about water use and water sourcing, and what that means for the industry and the kind of trends that we're seeing. We'll also talk about water contamination and pathways where we've seen contamination happen and ways to mitigate that. Concerns around waste disposal — there is particular attention that needs to be taken to a lot of the material that is used in a lot of the development of shale gas. We have to pay particular attention to how that is handled and disposed of.

We'll also speak to air emissions and greenhouse gases, go over some surface land and habitat disturbance, legacy issues, as I mentioned before, and then more broadly speak to the cumulative effects that are seen and result from shale gas development.

First off is water use. I'll speak to the graph first. Basically this is data that is from the northeast of B.C. and the water that is used for each well

We're looking at volumes of water that are used on an individual well basis. The key thing to note here is that it's very geology-specific. It depends on the formation and there are big differences. So Horn River, for example — you're upwards of 80,000 metres cubed per well, whereas most of the other formations that are being developed are around the 5,000 to 15,000 metres cubed per well.

The key thing to note is that fresh water is usually the easiest and cheapest source of water. It's the predominant source currently in B.C. and is always the typical source of water that is used initially before the production starts to ramp up. There may be economics to look at other sources of water.

The amount of fresh water that is being removed from the water cycle is increasing over time. As we see longer drill lengths and more fractures per well, it tends to be increasing as well. This can be resulting from the majority of the development that has happened going after some really good reservoirs, and as the technology develops, they're able to extend the lengths of the wells and increase the number of fractures to get more of the resource out of the ground. What that means is water volumes go up.

The other thing to note here is that the withdrawals are coming from both surface and groundwater so we need to have an understanding of how that impacts the different water bodies and the interaction between the surface and the groundwater that this may contribute to.

Contamination risks — the Committee has already heard a lot about the different areas and different pathways of contamination that can happen around the well border and the ways that leaks can happen around wells.

Just to reiterate a little bit, the casing and cementing — if it is not done properly initially, there can be pathways for the fluid to migrate around the casing and through the cement, especially if there are cracks that cause the ability of the fluid to migrate to underground aquifers. There are a number of pathways as well that could happen there. I won't go into too many details on this as we have already gone into a lot of that in some other presentations.

Some other areas of concern for contamination risk are fluid handling at the surface and this can be especially impactful to local aquifers' surface water and other areas like that.

Another contamination risk that can be prevalent is NORMs, or naturally occurring radioactive material, which is radioactive material that is in the reservoir. Once the reservoir is developed, it is extracted and produced along with the gas and water that comes to the surface, so there has to be specialized handling and disposal of this type of material. These are just a subset of some types of contamination risks and concerns that typically are associated with shale gas development.

We get a lot of questions around fracture fluid additives and this is a key component and a key concern for a lot of stakeholders. Basically, fracture fluid additives are chemicals that are added to the water and sand to create a mixture with desired properties so that it can fracture the formation in the way that the company would like it to be fractured.

The key thing here to note is that the risk is always greatest when they are in their undiluted states. They are brought to the site generally undiluted and then mixed with water and sand right at the well pad. As they are travelling and being transported there are risks of accidents and spills and there has been a lot of concern around that. In some case studies in the U.S. that has been a major concern.

The contamination from fracture fluid additives can happen in a number of different ways. Contamination happens through surface spills. Also, as the flowback water — or the water that comes back up from the well — is handled at the surface, it needs to be done in a way that prevents contamination. It also can happen with the migration of the fluid in the wellbore, as we discussed earlier.

Some options that are available — there are non-toxic additives that are out there and are being required in certain uses and jurisdictions. Potentially over time, as that technology develops, it could reduce the risk, but it's not widely used yet in industry and remains to be proven on a lot of different applications.

There have been some good steps in terms of the disclosure and clarity of the chemicals that are being used and where they're being used. This is generally done on websites now, so there's FracFocus, which allows governments to have a registry of the different chemicals that are being used at the fracturing sites. There are still some challenges around this — the clarity on proprietary chemicals is still an issue. Companies are allowed to use proprietary ingredients and not disclose what those ingredients are. There are also concerns around the toxicity and what the actual impacts of these chemicals are to human health and to the local ecosystem.

Just a quick snapshot from a material safety data sheet from Schlumberger showing some of the different chemicals that are being used currently — there are a whole range of different chemicals, this is just a subset of them. Just a couple of things to note here in terms of the potential hazards and the disposal that's required, so we can see everything from hazardous waste disposal facility requirements to incineration, landfills, hazardous waste landfills and deep well disposal.

This gives you a sense of the types of specialized handling and disposal mechanisms that need to be in place in order to deal with these chemicals as they're brought back up to the surface after the hydraulic fracturing takes place.

Transitioning into waste disposal — as we are talking about it there — there are a number of different ways to dispose of this waste. I should note that there are fluid — liquid — waste and also solid waste, such as drill cuttings and things like that that need to be handled. I'll speak mainly to the liquid waste portion of it as that's one of the main concerns. There are options available. Generally what happens is — especially in B.C., for example — deep well disposal is used. This may be the best option if there are a certain number of conditions that are able to be met or is the only option in certain jurisdictions and for certain types of waste. So if there are radioactive materials present in areas of low-seismic risk and the fluids are not expected to migrate, this is probably the best option. What this means, though, is that it requires strict monitoring. Some other consideration is that the capacity is not limitless. There is only a certain capacity that these disposal wells can handle, and the pressures must be very closely regulated to prevent over-pressurizing the formations where the fluid is being disposed. This is a concern, as it has been linked to potential seismic events that happen as a result of that.

Some other options are available, such as using mobile treatment facilities. These are usually brought to the site. They can be fairly costly to use, so it's not always the primary option for industry. There are permanent treatment facilities and we need to consider the bigger infrastructure and capital outlay that has to happen for those to be implemented in areas.

The other option that is being used in certain jurisdictions is that they are shipping this waste elsewhere to try to get it out of their areas and to get it into a jurisdiction that is willing to deal with it. A key point here, and this has been a really big concern in the U.S., is that municipal treatment facilities are not at all equipped to deal with this type of waste. It is a totally separate system that needs to be implemented and different types of facilities need to be built in order to handle this type of waste.

Overall, the waste management options need to be really carefully considered and the safest option should be chosen. Again, that is very site-specific and very dependent on the types of waste that you're dealing with and can change depending on where you are.

Water conservation protection — there are a couple of options here that I'd like to touch on. So, water re-use and recycling is a big trend nowadays and industry, especially in the U.S., is moving more and more toward re-using flowback water and recycling its use. For example, some of the operators in the Marcellus, which is in Pennsylvania, are re-using about 96 percent of the produced water. This generally happens further along in the production cycle, when there is more water and infrastructure available for them to do this, but the trends are moving that way.

Another option is saline groundwater use and there are examples of this in northeast B.C. It is possible, but there are considerations that need to be in place because the saline water needs to be contained and can't be released into the freshwater systems.

Casing and cementing integrity — we've heard about the potential pathways and the ways that casing and cementing can fail and the wells can leak, so there should be continuous monitoring in place and production should be halted if there is leakage that is found to be occurring. It's not just for the production wells but it's very important for the disposal wells as well.

Then in terms of surface spills, so surface spills are something that is inevitable. There's a certain rate of spills that happen with any type of activity. Prevention and monitoring measures should be in place and all companies should be required to adhere to the guidelines that are outlaid.

Regional water management — this is a fairly complex issue. I'll try to touch on a few points here. One key component to water management is having proper baseline water quality and quantity studies so that you're able to assess what the water system looks like prior to development. This is really important so you can gauge how the hydrology will react to potential disturbance that's going to happen. Monitoring is an essential part of this, and the key thing about monitoring is it's not just an exercise in collecting data; it needs to be used and used to inform the ongoing regional planning and the strategy that is required for the industry.

This is especially important where there are different competing uses of water, such as domestic water use, agriculture or power, things like that, and especially important where the seasonal water level fluctuates. This is particularly important as a lot of times development activities coincide with low-flow periods in the water levels and you can see companies trying to use a significant portion of their water demands during periods where the system is not able to accommodate.

Ensuring that there is adequate disclosure and transparency in the data that shows what activity and performance is happening in the field and using this data to inform the strategy going forward. So the key takeaway here is that there's a need to understand the hydrology prior to development and to manage the water resources in order to maintain the quality and quantity so that it can support other uses and maintain a healthy ecosystem.

Speaking about air emissions — the main concerns here are about the local level-airshed and the impacts to the local ecosystem and communities around here, so what we see from shale gas development is there are air emissions in the form of particulate matter. There is NOx and SOx. There is methane, volatile organic compounds and some carcinogens, such as benzene. These are all released through a number of different ways, but it can be in terms of the flaring, in terms of venting and fugitive emissions that are happening at these sites and the facilities. Special consideration needs to happen if any of this development is coinciding in close proximity to other communities or to areas where there are people who are accessing the land.

So the key thing here is that airshed quality should be continuously monitored and there should be airshed quality monitoring regulations that look at all this and also continuous improvement should always be encouraged. This is something that is able to be encouraged by regulation and set out so that industry knows that they're expected to keep reducing these types of emissions and reduce the risk to local communities.

Greenhouse gases — there are a number of different sources of greenhouse gases when we're talking about the shale gas and unconventional oil and gas development. The primary source of greenhouse gases in any type of fossil-fuel extraction is the end-use combustion and that's going to be wherever the gas or oil is eventually used at the end, the majority of the emissions will happen there. In terms of the extraction process and the development that is happening on the ground, the key sources of emission to consider are the combustion of natural gas to power the actual facility, such as compressors and processing facilities. That's a really large source of greenhouse gases. One way to reduce that source is to electrify those facilities and require them to be powered by a grid that is clean and incorporates renewables.

Another big source is $CO_2$ that is found naturally occurring within the formation. In B.C. again, Horn River, for example, has a formation $CO_2$ content of about 12 percent. Some of the other ones are substantially lower. Montney is around 1.5 percent, but it's very formation-specific. It needs to be looked at on an individual basis. Right now this $CO_2$ is removed during the processing and is vented to the atmosphere.

Another source of emissions to consider — and this is a key category that needs to be looked at — is methane venting. Methane is another greenhouse gas and the key thing here is that it has a much greater warming potential than $CO_2$. What that means is that, for each molecule of methane vented, it has a much greater impact on the warming of the planet than one molecule of $CO_2$, so smaller venting volumes of methane have a greater impact.

There is a considerable debate right now around the exact volumes of the methane venting that are happening in relation to shale gas developments. There are a number of studies that are ongoing, so we are still waiting for some clarity of a number of different components along the supply chain to figure out what the actual volumes are. The ranges are quite broad at this point so there is a lot of work that needs to be done to figure out what those emissions actually are in the field.

Another key consideration is flaring and the trends that happen with unconventional developments. Flaring has been on the rise in Alberta and the U.S. recently, and this is generally due to the unconventional development and the amount of gas that is found in conjunction with some of the tight oil reservoirs that are in those areas. In those areas they are seeing that, so it needs to be considered and there has to be adequate regulation in place so that it reduces the amount of flaring that happens resulting from the increased development.

Here is a quick little chart of the current emission sources from B.C. just to give you a sense of how the breakdown looks and where the major sources of emissions are. We see the major sources are from the natural gas combustion, and this is the combustion that is used to power the compressors and processing facilities and transport the gas through the pipelines.

Another major source is the venting of the $CO_2$ from the formation, which I spoke of earlier. The other sources are methane venting and fugitive emissions and the flaring that is happening there. This is the current breakdown right now, as of 2012, so it shows the landscape as it is right now, which could change substantially depending on where development goes and how it proceeds in the future.

It also shows the areas where you can make the biggest improvements by changing some of the aspects of it.

The key things here are: we need to consider the life-cycle emissions, including all the flaring and venting and formation $CO_2$, as well as the transportation distances, and so forth, so that we can work to reduce those emissions and limit emissions across the supply chain, not in one specific area only.

Switching gears to surface and land disturbance — this is kind of the footprint that we see on the surface. This is everything to do with the roads, the pipelines, the seismic, all the camps and everything else that is required in order to allow this development to happen. It's important to consider all the overlapping infrastructure that causes fragmentation of the landscape and leads to exceeding ecological thresholds. For example, in the picture here, you have a number of different infrastructure footprints that are shown and depicted that show the amount of linear disturbance that happens as a result of this type of development. It gives you a sense that the impacts are not just on the specific size of the clearing that's happening, but the impacts extend out further as it fragments the landscape and prevents the use of the habitat by certain species.

Regional planning should consider all these different aspects as well and should account for the plans of many projects — as opposed to just on an individual project level — and work to reduce the footprint by avoiding duplication of infrastructure and aligning infrastructure wherever possible to reduce the amount of fragmentation to the landscape.

Now I'll just talk about a few different aspects of development that happen at different phases. Seismic activity is a key consideration that generally happens at the beginning of the development. It is used to evaluate the subsurface geology. Generally what happens — you can see in the top picture on the top right — is that it creates a grid pattern in the landscape. This linear disturbance impacts predator-prey relationships and can significantly decrease populations of certain species of wildlife as the habitat changes and they are no longer able to evade predators as they once did.

There are different ways that you can do this. The bottom two pictures show two different methods of cutting seismic lines. The one on the left is a low-impact, hand-cut line. You can see the scale there with the ATV, showing it is much less impactful and it doesn't create the line of sight that the mechanically cut seismic line shows on the right-hand side. So there are alternatives that can be required. There are also considerations around the soil compaction that happens, especially damage that can happen to wetlands and riparian areas — again, considering both the direct impacts and the indirect impacts such as the habitat fragmentation.

Another stage of development is site preparation. This is where the clearing of the roads and the well pads happen, and there is significant activity that is clearing the land and making it ready to be drilled and developed into the facilities.

There is a significant amount of on- and off-road vehicle activity that happens at this stage. There is a lot of equipment moving on and off the sites, and another key consideration is that the pipelines generally follow once the production is proven. So you'll see a lot of the site preparation happening at the exploration stage and the pipelines and some of the other bigger infrastructure happens once the production has been proven.

Drilling and completion — again this is a quite active phase of the well's life cycle. There is a lot of equipment required on the site and heavy trucks and equipment are being transported on and off the site to facilitate the fracturing of the well. This has impacts for local communities as there are significant traffic and noise considerations and other residual impacts that result from that. Activities should be planned so that this is reduced — especially around wildlife — it should be reduced so that it doesn't impact wildlife during key seasons. That could really significantly impact those populations. It should also consider the local community impacts and potential limitations to communities that are trying to accommodate this volume of activity.

After wells are drilled and production starts, the longer period of time that follows that is the operation and the production. This requires wells, processing plants, pipelines and a lot of other infrastructure so it is not just a bunch of well pads that we're considering. We have processing facilities that come along with it as well. This is a picture of the Spectra gas plant near Fort Nelson. It is in the Horn River Basin, so it's a processing facility that removes contaminants from the gas, such as $CO_2$ and $H_2S$, and cleans it up and then sends it in the pipeline.

One key thing here is that, during this phase it is important to have data transparency so that we're able to benchmark and understand how the companies are doing in terms of their performance. This helps us drive for continuous improvement in the process and always expect the footprint or the impacts to reduce as we go forward.

Then at the end of the project we enter the reclamation stage, where we try to return the disturbed land to a pre-disturbed condition. The key thing here is that the majority of the time it can never be returned to its original state. It is generally returned to another specified land use. What this means is muskeg and wetlands, for example, are very hard to replicate and generally that means reclaiming them to an upland condition, such as a spruce or other upland mixed forest. That is to state that there is an impact even after we reclaim the land — it is never truly returned to its pre-disturbed condition.

Reclamation needs to proceed — and only proceeds — if the remediation is complete, so we have to have remediation of spills and any other contamination that remains on the sites. We require testing that confirms that those regulations have been met. The key consideration here is that there are generally fairly long lag times between when a project is actually finished and the site is reclaimed. That's due to a number of different reasons, but there are roads that are being used for other purposes at this point and the infrastructure generally takes a long time to get removed and fully reclaimed.

So speaking a bit more about the end-of-life issues and the legacy issues associated with this type of development, we have a long lifespan of activities. We have production stages that take a long period of time but, before the production even starts, we have exploration that is happening and it's moving into areas. Then the abandonment takes a significant amount of time to abandon the wells and remove all the infrastructure and then conduct the remediation and reclamation activities.

The key thing to consider here is that abandonment, remediation and all of the end-of-life type of issues need to be properly thought out and regulation should be in place prior to development happening. This provides clarity about how the development will be returned to its — or in what condition it will be returned after the development happens and provides clarity, not only to the public but to industry, about what requirements they're going to be expected to adhere to once they're done their activities.

Another consideration is the long-term liability. After all of this activity happens and the wells are abandoned, there is potential for long-term liabilities associated with leaking wells — as we've heard earlier today — and even orphan wells, which are wells of companies that go out of business and are basically no longer liable. So if somebody needs to be held accountable for that, mechanisms such as orphan-well funds and legacy funds should be established so that it's understood where the liability lies and who will be accountable for the end-of-life issues.

Another key question is that ensuring long-term wellbore integrity is still a question mark. We're still trying to figure out the science behind that and how well we're able to assess that is still a bit of a question mark and provides liability as well for the public, potentially.

The other key consideration at the end of life is that generally there is — we're moving into areas were there wasn't significant access originally, so as we move roads and other infrastructure into these areas, these areas are opened up to other uses, not just the oil and gas. So we have other industrial uses, but also the public has access to it and that creates additional levels of disturbance and potentially extends quite long after the actual oil and gas development is happening.

So, moving on to cumulative effects — cumulative effects, again, to reiterate, are just the impacts of all the different smaller projects and infrastructure that's put on to the landscape or to the water system and how that is overlaid on top of each other and the greater impacts that result from that. So here is just a Google Earth snapshot of the Horn River — one area in the Horn River Basin — and we can see roads, pipelines, well pads, storage ponds and a number of other types. The seismic line — you can see the grids there, as well as forestry and some other industries that impact the landscape. So there is a number of different overlaying of layers that get overlaid and add to the different impacts here.

So key things include monitoring — so establishing baseline assessments for key parameters such as wildlife and other key data points is important and then continuing that monitoring on an ongoing basis to establish how things are changing going forward.

It also includes setting thresholds based on science and traditional knowledge — setting those thresholds and targets so that it is clearly understood how companies and activities that are happening are proceeding and whether or not they are getting close to or exceeding those thresholds.

Also establishing no-go protective areas for sensitive wildlife and habitat is very important as well as culturally significant areas. This should occur at a regional level and not the project level. If we are regulating projects at an individual level, it doesn't capture the full extent of the effects. It has to be looked at more broadly and from a regional perspective in order to get the full picture. We need to ensure that this incorporates all of the industries and stress on the landscape, not just oil and gas, but should include any other infrastructure or industries that potentially could be using the area as well.

Some other key considerations for cumulative effects — the pace and scale of development is a key consideration that is very important especially with unconventionals as the scale. It can be quite large and the pace can rapidly shift. It can get quite fast, depending on different market conditions and things like that. We need to ensure that that allows the ecosystem to maintain integrity and also that the local economic benefit is not overwhelmed and we are optimizing the economic benefit that is felt locally.

Regional planning and cumulative effect management are really necessary components to minimizing the impacts of unconventional development, as it is quite intense and can be quite overwhelming to local communities and the environment as well.

Enforcement is a key component that has to be incorporated here and it requires a certain extent of capacity at the government level in order to enforce these types of regulations and ensure that the activity is proceeding accordingly. The other thing to include there is that it's very important to include all stakeholder groups in this process and ensure that the stakeholder groups are effectively being engaged and that the communication is proceeding adequately in terms of the stakeholder group perspective as well.

Just to conclude here, unconventional oil and gas has large scale implications. There is large-scale planning and monitoring that needs to accompany this. There are technologies and practices that exist to reduce some of the impacts, but obviously not all the impacts are able to be reduced if we're expecting the type of development that has happened elsewhere. Communities should have access to independent information and have a meaningful role in the baseline assessments and monitoring and project- specific monitoring as well as the decision-making that follows that.

That's the end of my presentation.

**Chair:** The Committee is going to recess for 10 minutes while we get prepared for the question period. I believe the page has collected the questions from the gallery, so thank you.

We will reconvene in 10 minutes.

*Recess*

**Chair:** Order. Committee is going to reconvene. We're going to proceed with questions and, as mentioned previously, please wait until you're recognized by the Chair and your microphone is on before speaking.

We're going to start with a question from Mr. Silver.

**Mr. Silver:** Thanks to Adam for the presentation today.

We've been hearing some conflicting data today, and I was wondering if you had data on the average production life cycle of a fracked well in northern B.C. and Alberta? I'll start there.

**Mr. Goehner:** Yes, to start off, an unconventional well or a hydraulically fractured well can mean a couple of different things. There are a number of conventional wells that can be hydraulically fractured as well, so when we're talking about unconventional wells, which is the hydraulic fracturing and horizontal drilling that is happening in northeast B.C., those generally have shorter lifespans than a lot of the other conventional wells. That is generally due to the production being quite large initially and it tapers off relatively rapidly.

I don't have a specific statistic in terms of the wells in the different regions. It changes depending on the region and depending on the formation. In northeast B.C., you see the tapering happen quite rapidly within the first three to five years. Then it kind of tapers off to a much lower level after that.

**Mr. Silver:** What are other jurisdictions doing to police the fracking fluid chemical compositions? Usually more important than what chemicals are used is the question of how much of these chemicals are being used when we're talking about the ecological thresholds. Is this determined by federal regulations or in the development permits of each province and territory? Historically, in other jurisdictions, how difficult or how easy has it been to enforce compliance to disclosures of the quantities in terms of proprietary information versus regulations?

**Mr. Goehner:** Disclosure is a relatively new aspect. It has just come on-line in the past three to four years. It started out in the U.S. They started a program called FracFocus.org, where a lot of the chemicals are being disclosed. B.C., Alberta and now the NEB are using FracFocus.ca and that is all quite new.

The amount of the chemicals is not strictly regulated at this point. It is applied for in the permits, but it is not a determining factor and I'm not aware of any permits that have been denied based on the composition of the chemicals that are being used in the fracturing fluid.

At this stage there is disclosure that is happening, aside from the proprietary chemicals that are being used. We still don't have clarity on what's incorporated in those chemicals, but the disclosure is happening and that's about the extent. There haven't been a lot of regulations trying to understand what to do with that disclosure or limiting the types of chemicals, other than a couple of regulations in Alberta that require non-toxic additives that are being used in groundwater zones and so forth. Other than that, in the shale gas types of development, there is not a lot of regulation that specifies exactly what can and cannot be used.

**Mr. Silver:** My final question would be, can you explain the Synergy group in Alberta and where they get their funding and what your organization's connections are to these organizations?

**Mr. Goehner:** Sorry, can you clarify what the Synergy group is?

**Mr. Silver:** Just Synergy Alberta, I think — SPOG and their affiliates — the Synergy group for Alberta for the oil and gas industry. Is there any connection between their activities and yours at Pembina?

**Mr. Goehner:** Unfortunately I'm not that aware of that group or how they are involved. In my activities, I'm primarily based out of B.C. So if we are involved in that process, unfortunately, I'm not aware of that.

**Hon. Mr. Dixon:** In Yukon, 100 percent of the hydrocarbons we use come from outside of the territory. Given your understanding of the life-cycle impacts of natural gas produced involving fracking, how would you compare that locally sourced natural gas with imported fossil fuels from a climate change perspective?

**Mr. Goehner:** That's a really good question. It's a complex one and it depends quite a bit on different aspects of it. The end use is always the biggest component of the overall emissions for a fossil fuel. Generally speaking, coal has the largest emissions profile of any of the fossil fuels, and after we look at a lot of the other aspects of it, there are significant areas of uncertainty that are still waiting to be understood in terms of how the overall life-cycle benefits of shale gas or other unconventional hydrocarbons compare to the other alternatives that are out there. At this point, I would say there is quite a bit debate surrounding that question. It's currently a debate that is being studied in a lot of different jurisdictions, but it's not one that has been definitely proven at this stage.

One key component, as I mentioned in the presentation, is the question around methane venting, as that's a big contributor to the overall greenhouse gas life-cycle emissions of shale gas. But again I would say that in terms of the locally sourced fossil fuels, the transportation of fossil fuels is a very small portion of the overall life-cycle emissions that contribute to the entire emissions for a fuel. So, transporting the fossil fuels from different places or regions generally does not add a significant amount of emissions to its overall profile.

**Hon. Mr. Dixon:** My understanding is that there's some limited fracking going on in Northwest Territories — obviously in B.C., in Alberta and, I believe, in Saskatchewan. Do you know of a jurisdiction that has it right, that has a system we could model ourselves after, or is there a hierarchy, I guess, of quality in terms of a regulatory system among those Canadian jurisdictions?

**Mr. Goehner:** In general, I would say the jurisdictions that have the most experience at this stage are the ones that probably have the most data to work with and the ones that can be looked at to learn some lessons from. The complication is that regulation has generally been following development and has never really been in front of the issue at this point. I would say there is a lot of effort being made in different jurisdictions, and B.C. and Alberta are definitely working to understand the issues and resolve some of the key complexities that surround the unknowns about this issue. But I would say that in every case there are still significant gaps in terms of the overall management and regulations that surround the bigger picture items, especially cumulative effects.

I would say that there's a lot of work that needs to be done in all the jurisdictions around that subject, and then overall impacts for air emissions and greenhouse gases — there is still a lot of work and science that needs to happen in those respects, as well as the long-term wellbore integrity. There are still lots of remaining questions there that haven't been addressed in those jurisdictions.

**Mr. Tredger:** Thank you to Mr. Goehner, for his presentation. Mr. Goehner, one your recommendations is that there is a need for data transparency to enable benchmarking and performance monitoring. I would assume that would include baseline data, ongoing monitoring and response, and the effectiveness of responses.

I have a number of questions around that. How can we ensure that the data we are getting is independent and verifiable? Given the rapidly evolving nature of hydraulic fracturing, how can that data be achieved in a timely manner when industry is giving a significant time window — two to three years in B.C. — to keep their data private?

A number of presenters to the Committee have mentioned the lack of independent data and the inability to access data on the well sites. What has been your experience and Pembina's experience in following up on these issues?

**Mr. Goehner:** There are a few questions. There is not a lot of clarity around the data that is being collected and how it is being provided to the public or other stakeholder groups that need to access the data. I would say that in general the industry does collect data and, yes, there are proprietary aspects to that that need to be considered.

However, the key data points that need to be considered for environmental impacts potentially don't fit under that category and there hasn't been as proactive of a push from industry to release that or from government to require that data to be released in a timely manner. So there is some of it available. The other consideration there is that a lot of it just hasn't been collected and it hasn't been systematically addressed early on in the stages, so we don't have a lot of baseline data for a number of areas that have already undergone or seen significant amounts of development. We don't have the ability to compare back to what the conditions were prior to development.

That's a key aspect that should be considered and should be looked at prior to approving projects — whether or not there is adequate data in a region to assess what the baseline conditions are.

**Mr. Tredger:** Communities should have access to independent information and have a meaningful role in baseline and project-specific monitoring as well as decision-making. That was one of your conclusions. Is that happening anywhere? Is there a model that we could follow? What would you say is an appropriate amount for communities to have?

It's one of the struggles that I encountered when I went on our tour in Alberta and I'm hearing from residents of B.C. — that they don't feel they have enough access to independent information. Is there a jurisdiction that is providing that, and has successfully done so that we could model on that?

**Mr. Goehner:** In most of the jurisdictions, as you mentioned, my experience has been the same. The local communities have not felt that they've been adequately engaged in the process and that there is still a lack of independence of the data.

They seem to be getting a lot of the data directly from industry without third-party verification or some sort of system that allows an independent eye on the data prior to it being distributed to the public.

In terms of engaging the local stakeholders, there are a number of different programs that attempt to do this. From the local community perspective, I have not been aware of any that are established and that meet those types of criteria you mentioned — of the community feeling adequately informed about the decision-making that's going on.

**Mr. Elias:** I think I'll start with the social side of the ledger here. Over the course of our work, we've had so many conflicting conclusions, whether it be scientific to scientific, scientific to community groups, scientific to industry, and vice versa. Some of the work that you say you do on your website includes work with community groups and First Nations and such. We've met with people like the Cochrane Area Under Siege coalition and people from Red Deer saying they come to us and submit testimony that they feel that their water is contaminated, they feel that the flaring is affecting their health and their livestock and their lands, yet there are no reported cases, whether it's with the regulators or with industry themselves. There's no connection.

Does Pembina do any work on the social side of the ledger in order to either study or understand that aspect of oil and gas development?

**Mr. Goehner:** First, yes, we do work in that area and we do work in trying to bring stakeholder groups together to have a shared understanding of what the issues are and work to find ways that those questions can be answered. I would say that one key barrier to getting a lot of those questions answered and having those communities feel comfortable with what is happening is that the — there's a lack of funding for scientific studies in a lot of cases. There's potentially not as much attention to some of the details on in terms of the types of environmental impacts that those community members are specifically concerned about. The extent that the industry and government is engaging with those communities falls short of their expectations or doesn't reassure them, because there's not a sense that the data that is being conveyed is independent or is accurate, based on their experiences.

**Mr. Elias:** This last question here is actually perplexing to me. There are hundreds and hundreds of thousands of wells whether they're conventional or unconventional — actually I don't even like the work unconventional anymore, because it suggests that it's out of the ordinary — it's not out of the ordinary anymore in my opinion — but out of everyone we talked to, no one seems to know what percentage of wells leak to surface and it's perplexing to me really. That includes surface casing vent flow and methane migrating to surface. You mentioned a couple of studies under your greenhouse gas methane venting. I don't know if we have those studies, maybe you can give them to us or give us the titles of them so we can figure out if we have them or not, but they're ongoing. You said they were, right?

Does Pembina do any work with regard to looking at the percentage of wells that leak to surface?

**Mr. Goehner:** It's a really good question and it's an area of uncertainty at this point, I would say. From my understanding, I have not been able to find that exact number either and it has been a number that is difficult to obtain. There are a lot of complexities involved in figuring that out, and what it comes down to is the monitoring either isn't in place or the data transparency isn't there so that the governments are releasing those numbers. For example, in Alberta, we've been trying to figure out the exact number of surface casing vent flows, as you mentioned, as one source — it's a type of leak that happens that is actually reported — and that number is fairly difficult to obtain. We're actually working to try to find that, but haven't found that explicitly stated in the public domain at this point. I would say data transparency is one aspect and the pace that the development has happened. The scientific studies have not been able to answer all those questions yet, so it kind of lags behind. Hopefully we'll be able to provide clarity on that once some of these studies are released.

**Chair:** Thank you. I just have one question.

It has to do your statement that "Flaring has been on the rise in Alberta/U.S. due to unconventional development." The Committee has been told that that additional — or that increase in flaring — is largely due to the development of conventional resources. I wonder if you can try to clear up the discrepancy.

**Mr. Goehner:** Yes, from the work that we've done and the reports that we've reviewed, the primary areas that have been of concern for flaring and venting increases is gas that is produced alongside oil. This has been a concern because the regulations that require the conservation of that gas are tied to the economics and whether or not the gas is economically feasible — or makes economic sense — to recover it and conserve it as opposed to flaring it. Because gas prices are at a fairly low level right now, the economics don't require — under the regulations — that the companies conserve that gas. So the trends that we have seen are generally due to the increased tight oil development in some of these jurisdictions, especially in the Bakken region. It is one area where the flaring is quite extensive and has been on the rise quite a bit. That was one of the areas that I was referring to in the presentation, and the other one is a recent report that was just released from the Alberta government that outlines the flaring and venting for the province. Historically, it has been decreasing quite substantially over the course of a number of years, but just recently in the past few years we've seen an upward trend. It has started to increase again and that's the correlation that we've been able to draw based on the data that we've seen.

**Ms. Moorcroft:** Thank you for your presentation, Mr. Goehner. I'm going to focus my questions on what you refer to as end-of-life issues. You spoke about reclamation and noted that in general it is not possible to return disturbed land to a pre-disturbed condition. You also mentioned the lengthy lifespan — that it can be as long as 60 years between exploration and abandonment — and that there is a need to establish comprehensive regulations for abandonment, remediation and reclamation.

The first question I want you to respond to is, what monitoring does occur of abandoned and orphaned wells and are you aware of any fully reclaimed areas?

**Mr. Goehner:** Yes. That's a complex issue as well. There are a lot of components there that I touched on. In terms of areas that have been reclaimed, yes, there are a number of areas that can be reclaimed and again, the distinction there is that they're not always brought back to their original state. They are reclaimed to a different condition that is deemed suitable by the regulator. There are well pads and pipelines and other areas that are reclaimed all the time. It's part of the regulations in most jurisdictions.

In terms of having those regulations clear up front, I think that's an important aspect. We've seen this in certain jurisdictions where those expectations are not clearly laid out in the regulations as projects are proceeding, and the challenge then is that there is no clear expectation of what needs to happen after the development happens by both the government and the industry, so there can be discrepancies in their views about what should happen to that land after the production is finished.

**Ms. Moorcroft:** You mentioned that the pace and scale of development of fracking can be very intense, more so than for conventional oil and gas, and overwhelming to local communities and the environment. Does this make it particularly difficult for regulators to keep up?

**Mr. Goehner:** Yes, I believe this aspect is very important. What has happened in a lot of jurisdictions, especially jurisdictions that have not seen a significant amount of oil and gas activity in the past, is that the regulator doesn't have the capacity initially to deal with the amount of applications and permits and the necessary amount of regulatory oversight needed to properly address these types of impacts and these projects that are going forward. I would say that the pace and scale of unconventional — one illustration of that is the pace that has happened in the northeast U.S., which has significantly overwhelmed the regulators in those jurisdictions because they had not seen very much oil and gas activity previously and the regulators have been playing catch-up to the industry activity that has happened in those jurisdictions.

**Ms. Moorcroft:** So you've mentioned that there is a gap between community expectations and what occurs particularly with abandonment, remediation and reclamation regulations. You've indicated the need for those to be established and to be more comprehensive. How much control can governments realistically exert on the scale and intensity of fracking once it has begun in the area?

**Mr. Goehner:** That is a question that the government can answer. The pace and scale don't have to be determined by industry itself. It can be determined in conjunction with all the stakeholders at the table. I think there are a lot of complex issues that need to be addressed and there are differing interests that have to be weighed when trying to answer that question.

In terms of how much power the government has to adequately change the course of development, that is a question that the government has to answer, I would believe.

**Chair:** We are going to start with the questions from the public gallery now. Mr. Silver will lead us off.

**Mr. Silver:** This question comes from Jacqueline Vigneux and the question is, what is your experience and knowledge about drilling horizontally in permafrost?

**Mr. Goehner:** I have limited experience with drilling in permafrost; I am by no means an expert on that. I do know that there are special considerations that should be implemented and there are some jurisdictions that require different procedures in order to protect the permafrost, such as cooling drilling mud and drilling fluids that enter the wellbore so that it does not melt the permafrost directly adjacent to the wellbore and those aspects — but I don't have a significant amount of experience with that.

**Hon. Mr. Dixon:** This question is from Michel Dufeau from Whitehorse. What are the conditions in the Marcellus basin that triggered 96 percent water recycling and how does that compare to B.C. or Yukon?

**Mr. Goehner:** In the Marcellus there were a number of triggers that happened. The competing water uses in that area are quite significant. It is in an area that is adjacent to a lot of communities, a lot of agriculture and other competing water demands. There were also significant water scarcity issues that happened in that region and there was a lot of public concern around the issue that caused the regulators to enforce stricter guidelines around freshwater sourcing and permitting. Essentially it made the industry move toward the reuse and recycle of their fractured fluids.

B.C. for example — I believe around 75 percent of the water they use there is freshwater. There are initiatives that use saline water and do some recycling but, at this stage, it's primarily still freshwater, and for the Yukon, I don't think there is any yet.

**Mr. Tredger:** This question is from Werner Rhein, Whitehorse. Why is the Pembina Institute not involved in environmental database collection before oil and gas activities occur or any other industrial activities?

**Mr. Goehner:** We have a number of different initiatives that we try to engage on and are obviously limited by our resources as well, so in certain cases where we have resources that are available, we do engage on those issues and do engage with local communities. We are currently engaged in the Northwest Territories with several communities to create databases of operating procedures and practices that they would like to see implemented in their regions, but I would say it's — the extent of our involvement is limited, based on our resources, basically.

**Mr. Elias:** This question is from Don Roberts from Whitehorse.

Does your organization believe that fracking can be done safely without polluting water, without harmful methane and other greenhouse gas emissions and without harm to health?

**Mr. Goehner:** I would say that based on the available information and the state of the current science, we still don't have a clear answer to that question. Our primary concern is that there isn't enough information to adequately answer that question. At this stage, we are primarily calling for or we're hoping that there's an increased level of scrutiny and amount of effort put into the research that would be required in order to answer that question adequately.

**Chair:** I have a question from Julie Frisch. Her opinion is that air quality seems to be only an issue if it's near a community of people. Are wildlife and vegetables not a consideration? Oh, sorry — vegetation.

**Mr. Goehner:** Air quality is a definite concern for other aspects as well. I would say that the main concerns from most stakeholders are when they're in close proximity to communities and those are the voices that are most prominent about air quality. Wildlife and vegetation definitely can be affected and there are impacts to air quality on those aspects as well. There's no question about it, but it's not something that is monitored as much, so again there is not as much data to support those types of issues.

**Ms. Moorcroft:** I have a question from Rick Griffiths. Can you speak specifically of the impacts on land and communities when fracking has not gone according to plan?

**Mr. Goehner:** Yes, so there is I guess a number of ways where you could say fracking has not gone according to plan. In terms of communities that have expressed concerns around how fracking has happened around their local communities, there are a number of case studies in the U.S. and Alberta where that has happened. I can definitely point to those case studies after this and provide those to you. I would say it's quite variable and there are different concerns that are raised in different communities, so it's not just — there's no one answer to that. There are a lot of different impacts that communities are feeling and expressing and it's not always an easy answer to say that there is a quick and easy solution to resolve those problems easily. There is a lot more complexity to it.

**Mr. Silver:** This question is from Lois Johnston and I'd like to thank her for her excellent penmanship. Given the need for baseline water data and for completed regional land use plans and for the establishment of ecological thresholds — none of which have been completed in the Yukon — why are we even considering this industry?

**Mr. Goehner:** Again, there are a lot of competing interests in this type of question and there are definitely various sides to it. The experience has been in a lot of these areas that the development has proceeded based on economic merit and the environmental implications have not fully been understood and properly regulated prior to the development happening. I would say that it would be beneficial to have an understanding of those environmental impacts and have clear regulations prior to any development that does go ahead.

All I can speak to is what has happened previously, and that has not been the case and there have been a number of negative impacts resulting from that. If you can gain that science-based understanding and those ecological thresholds prior to developing the resource, that would be the most prudent way to go about the process.

**Hon. Mr. Dixon:** This question is from Sally Wright from Kluane Lake. What greenhouse gas $CO_2$ equivalent do you use for methane: 20 times, 70 times or 100 times more potent than $CO_2$? Do you recognize the most recent IPCC report that says business-as-usual means climate instability in 30 years?

**Mr. Goehner:** First the methane question — yes, the most recent version of the IPCC report states that methane has 25 times the global warming potential of $CO_2$ on a 100-year time scale. When it is looked at on a 20-year time scale, that goes up significantly. Given the urgency of climate change and how rapidly the reports and the data show that we're expected to experience significant thresholds that are going to be exceeded before the climate warms past those two-degree thresholds — or even a four-degree threshold — the 20-year time frame is significantly important to that question as well.

We use the most recent version of the Intergovernmental Panel on Climate Change reports and their figures for methane. We consider the 100-year time frame when it's applicable to the reporting requirements for different jurisdictions but, in terms of the impact on the climate, the 20-year time frame is significantly important as well.

**Mr. Tredger:** This question is from Sandy Johnston. Is there any research being done on the effects of depressurizing of near-surface and deep aquifers?

**Mr. Goehner:** I'm not aware of work that's been done on depressurizing aquifers. I'm not sure what that would be required to do. I'm not aware of that.

**Mr. Elias:** This question is also from Sandy Johnston. Should regulators be required to ensure that the cumulative effects of greenhouse gas emissions of all projects they approve do not violate the targets for greenhouse gas emissions?

**Mr. Goehner:** Yes, so the thresholds and targets and limits that are set on greenhouse gas emissions for jurisdictions, I think, are really important and it is becoming very clear that all major jurisdictions and countries are moving toward having targets for their greenhouse gas emissions. I think it is important to consider all sources of greenhouse gas emissions in those targets and not exclude any one source of emissions. I believe that looking at the greenhouse gas emissions on a life-cycle basis is the best way to do that and to capture an accurate picture of what's happening and to accurately account for the amount of greenhouse gases that are being emitted into the atmosphere. Setting those limits and staying within those limits is a key aspect to any type of legislation around that.

**Chair:** I have a question from Jacqueline Vigneux from Whitehorse: Have you read the Jessica Ernst catalogue on groundwater contamination in northwestern Canada, and do you acknowledge that there should be legal water protection instead of fracking in the Yukon?

**Mr. Goehner:** I have not read that report and I am not familiar with it. In terms of water protection in the Yukon, I think water protection is a key consideration. I think that water is something that definitely should be protected and conserved in the future, but I am not familiar with that report.

**Ms. Moorcroft:** A question from Sandy Johnston. What monitoring of wildlife health is being done — not just population studies, but actual physiological studies?

**Mr. Goehner:** I am not an expert on wildlife studies, but to my knowledge there are not a lot of wildlife health studies underway right now. As mentioned in the question, there are several studies looking at populations and the effect of different types of activities on population densities, but in terms of wildlife health, I am not aware of too many studies in that area.

**Mr. Silver:** Just for those in the gallery, if you see us going into the box and pulling others out, it is because we are seeing repeated questions. We are not picking. This question comes from Jacqueline Vigneux. As an environmental protection institute, would you suggest a ban or moratorium on fracking in the Yukon?

**Mr. Goehner:** As an organization, we're not advocating for moratoriums or complete bans at this stage. What we would say is that we would definitely suggest that there be adequate information and data collected prior to approving development. I would say a moratorium or a measured approach is a much more proactive and prudent way to go about it as you try to understand the issues and collect the data before proceeding to a production or development stage of oil and gas activity. It's a position that has not just been undertaken by Yukon. There are a lot of other jurisdictions that are still looking at this issue quite closely and trying to make a determination whether or not it is beneficial for their jurisdiction as well, so across Canada you have Quebec, which is still looking at this issue quite closely, and in the Maritimes as well. Internationally, there are quite a few other jurisdictions that also are taking a more measured approach and going about it much slower to try to understand the issues first.

**Hon. Mr. Dixon:** This is from Werner Rhein from Whitehorse, Mount Lorne. Methane emission to the atmosphere is increasing dramatically. Latest studies indicate over 52 percent of global warming is caused by methane. Why is there not more public exposure to this?

**Mr. Goehner:** I don't have a clear answer as to why there is not more public exposure to this issue. I think it is a very important issue and it is an issue that needs to be understood with a lot more clarity. There are still competing arguments and discrepancies in the science behind it and there are a number of studies in the States right now.

The University of Texas at Austin, in partnership with the Environmental Defense Fund, is undertaking a study that just was completed that looked at the well completions or hydraulic fracturing and the methane emissions associated with that. The Environmental Defense Fund is now proceeding with further studies that look along the supply chain of oil and gas activities to try to quantify the amount of methane emissions there. I would say that there is an increasing amount of public discourse around methane emissions and it's becoming more prevalent, but it's still not the centre of attention potentially that it could be.

**Mr. Tredger:** This question is from Sandy Johnston.

Full build-out of gas frack fields totally fractures the landscape. What studies on wildlife are being conducted to determine the effect of habitat degradation and fragmentation?

**Mr. Goehner:** That's a great question and there are a lot of concerns around that, because it's an impact that has not been considered in the past and is now being recognized as a key contributor to population declines in a number of areas. There are a few studies that are being done in the oil sands region and specifically looking at boreal caribou, for example, that have shown that the ecological thresholds for those species have been passed and are now in a state where those populations are potentially no longer able to sustain themselves and are declining at a rate that would suggest that they will not be able to recover.

So there are a number of different studies in those areas. I would say that there's a lot of work that still needs to be done to understand that issue and the complexity around the fragmentation and how that type of impact on the landscape can affect local populations.

**Mr. Elias:** This question is from Teo Stad from Crag Lake.

How and what cost would the fugitive emissions associated with gas wells and infrastructure be brought to zero? Given the longstanding problems with wellbore integrity, won't the proliferation of wells increase fugitive emissions overall?

**Mr. Goehner:** So I'll start with the second half of that question first. Yes, increasing the amount of infrastructure and pipelines and processing facilities and all the equipment that's involved with extracting gas and hydrocarbons will increase the overall amount of fugitive emissions. There's no question about — as you increase the amount of equipment, the amount of fugitive emissions do increase.

In terms of reducing the amount of fugitive emissions to zero or the amount of venting to zero, the economics of that can be quite — it's not always economically feasible for the companies to do that and that potentially can be a consideration as you're trying to develop the regulations and figure out whether or not it's in the best interest to develop in certain regions — it's to fully understand what some of the economic implications of having really strict guidelines and practices in place would mean and if that translates into a resource that it potentially is not economical to extract responsibly.

**Chair:** I have a question from an unknown author regarding air quality. Your slide notes "should be encouraged if the quality is deficient". How would you make the company comply? Do you often find this an industry issue?

**Mr. Goehner:** If I understand the question, I believe that it's stating that, if air quality is not adequate, how do you make a company comply with that? I would say the key aspect to ensuring air quality is at an acceptable level is ensuring that there is proper monitoring in place to assess those parameters and ensure that the air quality is not being exceeded by one of the parameters or another, that it's not being impacted that way.

**Chair:** We have time for one or two more questions.

**Ms. Moorcroft:** I have a question from Sandy Johnston. What is Pembina's estimate of the percentage of wells that are leaking in northeastern B.C.?

**Mr. Goehner:** Pembina has not conducted direct research into the number of wells leaking in northeast B.C. yet. We're not sure about that number, and it's still unknown for us as well.

**Mr. Silver:** This question is from Jacqueline Vigneux. It is, do you think that Yukon is going to be ready this year to say yes to fracking?

**Mr. Goehner:** I don't have a clear sense about that. I can't really provide a good answer to that question. I don't have enough information to be able to speak to that.

**Chair:** Fair enough, and since those were so short, we do have time for one more question.

**Hon. Mr. Dixon:** This question is from Don Roberts of Whitehorse. Can you tell us if your organization is part of, or contributes to, Synergy Alberta? I think you answered this one already. Synergy Alberta was the question Sandy asked before, so I'll try again.

From Werner Rhein in Whitehorse: is Pembina Institute telling regulators how often and in what period waste-water wells have to be inspected?

**Mr. Goehner:** To date, we have not done primary research on that specific topic, but what we do do is continue to engage with governments to try to proactively address those issues, and where there are concerns around those specific issues, we are engaging with the governments in the various jurisdictions to try to establish what those parameters may be and what the best practices could be that would be able to be implemented.

**Chair:** The time for questions has now elapsed. I want to thank Mr. Goehner and I want to thank the visitors in the gallery who submitted their questions. The Committee will try to follow up with the rest of the questions and do our best to get some answers.

Now we are going to proceed to a 15-minute recess while we await our next presentation.

*Recess*

**Chair:** I want to welcome everyone back to the proceedings of the Yukon Legislative Assembly Select Committee Regarding the Risks and Benefits of Hydraulic Fracturing. For those joining us for this presentation, I would like to introduce the members of the Committee.

I am Patti McLeod the Chair of the Committee and Member of the Legislative Assembly for Watson Lake. To my left is Lois Moorcroft, who is the Committee's Vice-Chair and Member for Copperbelt South. To Ms. Moorcroft's left is Sandy Silver, the Member for Klondike. Behind me is Darius Elias, the Member for Vuntut Gwitchin. To Mr. Elias' left is Jim Tredger, the Member for Mayo-Tatchun, and to Mr. Tredger's left is the Hon. Currie Dixon, the Member for Copperbelt North, the Minister of Environment, Economic Development and the Public Service Commission.

The Committee's mandate is set out in Motion No. 433, which specifies that the Committee is to develop a science-based understanding of hydraulic fracturing and also allow for an informed public dialogue. To this end we will hear several presentations over the balance of today and tomorrow concerning both the potential risks and benefits of hydraulic fracturing.

I would like to welcome the visitors in the public gallery and our next presenters: from EFLO Energy, Wayne Hamal, chief operating officer, and Blaine Joseph, the operations manager; from Northern Cross (Yukon), Richard Wyman, president, and Don Stachiw, vice-president of exploration; from the Canadian Association of Petroleum Producers, Alex Ferguson, vice-president of policy and environment, and Aaron Miller, manager for northern Canada.

EFLO, Northern Cross and CAPP will each give a presentation from the perspective of the oil and gas industry.

Following the presentations, we'll take a short recess before proceeding with questions, and if visitors in the public gallery would like to submit questions, forms and pencils are available at the entrance to the gallery. The page will collect the written questions toward the end of the presentations, and after asking a few questions each, members of our Committee will randomly select written questions from those that have been submitted by visitors in the gallery.

Time will not guarantee that all public questions will be asked and answered, but we will do our very best with the time allotted. I would ask that questions and answers be kept brief and to the point so that we may deal with as many as possible. Please note that these proceedings are being recorded and transcribed. If your question is selected, the information you fill out on the form may be read into the public record.

I would like to remind all Committee members and presenters to wait until they are recognized by the Chair before speaking to ensure that your microphone is enabled and for clarity to the listening public.

I'd also ask that visitors in the gallery respect the rules of the Legislative Assembly. Visitors are not allowed to disrupt or interfere in the proceedings. Please refrain from making noise, including comments and applause, and mute any electronic devices.

We're going to proceed now with Mr. Hamal's presentation.

**Mr. Hamal:** Thank you and good afternoon Madam Chair, members of the Committee and other members of the Legislative Assembly who may be in attendance.

My name is Wayne Hamal and I am the chief operating officer of EFLO Energy. Blaine Joseph, our senior operations manager, is joining me today and he'll be running the presentation.

We appreciate the opportunity to talk to you today. This presentation will address a little about our company, but it primarily focuses on our future plans and how they can be accomplished safely, efficiently and in harmony with the environment. In addition, I'll address the overall benefits to Yukoners of having the oil and gas business in your territory.

EFLO Energy is a public company engaged in natural gas exploration and production in the Liard Basin in southeast Yukon, specifically the Kotaneelee gas project. EFLO is dedicated to develop Kotaneelee because it has a significant conventional and shale gas assets. Prior to EFLO acquiring interest in Kotaneelee, the field had produced over 230 billion cubic feet of conventional gas. EFLO feels there remain significant volumes of both conventional and shale gas resources. The existing infrastructure enables immediate delivery of produced gas through an existing dehydration gas plant and Spectra pipeline for delivery to the Canadian and U.S. markets.

EFLO also envisions that Kotaneelee could be converted to liquefied natural gas, LNG, and distributed throughout the Yukon to enable a less expensive, cleaner, alternative fuel for power generation and vehicle consumption.

A little about our corporate culture — I want to highlight that we as a company respect the environment in the communities in which we operate. We have the background to ensure that gas is produced safely and responsibly, and we intend to promote collaboration and transparency with government regulators, First Nations and Yukoners.

The next slide is a map — just to give everyone a good understanding of where we operate. We operate in the very southeast — about as far southeast as you can get in the Yukon. We feel that being in the Yukon has a strategic advantage to keep Yukon gas in the Yukon and the benefits that brings. Kotaneelee historically is the only gas field that has produced in the Yukon, and we currently have the only gas processing plant there.

Kotaneelee has the potential to be a significant gas asset. As I mentioned, 230 Bcf of conventional gas has already been produced. EFLO's near-term plans are to continue to develop the conventional gas resource. However, the majority of the remaining gas at Kotaneelee is shale gas. Conventional gas may have five to 10 producing years remaining, while shale gas potential has an estimated 50-plus years of production life.

EFLO is here for the long term and would like to develop the significant shale gas resources that we feel exist in southeast Yukon. We also feel that exploration and development of this shale gas can be done safely and responsibly.

For the purpose of this forum, we want to illustrate to the Committee our long-term plan that incorporates the development of the shale. To put it into perspective, our current view of the conventional volumes are only about 10 percent of the total amount of gas at Kotaneelee. The remaining 90 percent of the resource comes from the shale. We are going to demonstrate that we will continue to safely and responsibly extract the gas resources at Kotaneelee. To be clear, by going beyond conventional resource extraction, we will need to fracture stimulate the shales.

Recognizing this, we want to focus on a few key points that demonstrate the ability to frack without negatively impacting the environment and our communities.

The key to well integrity is captured here on the screen: regulatory strength, design and execution — that's the key. With regard to regulations, Canada has some of the most comprehensive regulations and guidelines for oil and gas operations. Yukon Energy, Mines and Resources have utilized regulations from the federal and other provincial regimes and have established best-in-class practices that are embodied in the regulations we have here in the Yukon. The key takeaway is that the EMR and their regulations cover the drilling and testing operations as well as any regulators in the world in this field. The EMR regulates all aspects of well construction: casing programs, casing design, cementing programs, testing, drilling fluids, et cetera. These make up the criteria in which all wells are drilled and completed. These well construction regulations and practices are the key to successful drilling and well integrity.

This cubic model that you see on the screen depicts a typical drilling environment where there are many different types of strata from surface to the target reservoir. These may have different pressures, strata integrity — meaning some are harder and some are softer — and include the possibility of freshwater zones near the surface. Each well is designed to deal with these parameters that protect all the zones behind pipe and cement. Here we illustrate how a well is drilled and why the various steps are required to ensure integrity. All are designed with significant safety factors and redundancy.

Basically, wells are drilled in stages and require several casing strings to get down to the total depth. You can see what we're illustrating here is you would start out and drill a large, shallow portion of the well to clear all the potential surface waters that may exist. After you drill the hole, you run casing — which would be a thick, solid casing structure, a pipe — all the way down to total depth and then you'd pump cement all the way around the backside of that casing. So what you've done is you've isolated those zones from inside the well that you're drilling. At that point, you then test that casing. You can't go any further until you test it within the regulations set forth by our regulators. Once that is complete, you go to the next stage and you drill the next section of hole, you case it, then you cement it and you test it. What we're doing here as we go deeper is we're building this well out and we're making sure that we have integrity throughout the entire wellbore.

When we get to TD — total depth — we run our final production casing, we cement it all the way back to surface and then we are ready to complete the well. We run a final tubing string in the well, as you see, and that is the tubing that the production will flow up. So by the time we produce the well, we perforate the well, the gas comes in and it goes up the tubing string. In the end, what you end up with at the surface, which is what we're most concerned about — you've got essentially four casing strings, plus tubing, plus cement behind each casing string that is giving you isolating protection for those zones against any production that you may produce.

As you can see, we have a tremendous amount of redundancy and there are significant safety factors that are included in the design of the type of pipe and the wall thickness of each of those pipes.

That’s a typical — a Nahanni well is an example of what has been drilled and how we would drill future wells at the Kotaneelee field.

This is the same illustration as the previous page, essentially, that the right cube that you see on the right side of the page has the same casing structure, so you still have all the various casings, but what we’re depicting here is targeting the shales. You would then go horizontal in the shale section and set up for fracture stimulation.

With regard to fracture stimulation, an enormous amount of science and engineering is put into hydraulic fracture design. Fracture stimulation is designed to fracture the hydrocarbon-bearing strata only. This is a key takeaway. From an engineering perspective, you do not want to frack outside the zone of interest. This would be counterproductive to a successful completion.

It’s very critical to understand here. As you can see in these designed frack lengths — that’s kind of highlighted right here — this is from the wellbore going out to the end of the fracks, after the frack job is completed. Those frack lengths are designed to stay within the strata, right in through here. You don’t want them going outside the strata.

Typically these frack lengths are — they range, certainly, depending on how thick the shales are, anywhere from maybe 50 metres to 150 metres in length. I want to point out that these depths we’re talking about at Kotaneelee are about 3,000 metres deep. So we’re talking about frack lengths of 100 metres at a depth of 3,000 metres. Fracture stimulating a well is also very expensive so, as a commercial company, we would not want to spend extra money creating longer, bigger fracks when they are not going to do us any good. So it’s just another reason from a different perspective to show why we only want to frack within the strata. EFLO, like all companies, is driven by economics and therefore minimizing unnecessary frack lengths is economically sensible and that is what we want to do.

To reinforce what I have explained on the previous slide, I have included this chart. You have seen this chart before but I felt it was important to reintroduce this data. This slide is an example of tracking frack lengths in the Barnett Shale formation in northern Texas.

What you see here is the basic horizontal line, kind of the orange rust line, depicts the depth at which these wells were fractured. In the Barnett, you are looking at about 8,500 feet as the deepest well, up just above 5,000 feet — 4,500 feet was the shallowest well. The vertical lines are the lengths of the fractures that were created during fracture stimulation and these are monitored and measured through micro-seismic measurements, which is a very common and proven method of measurement.

As you can see, like I mentioned in the previous slide, you are looking at 200- or 300-foot frack lengths, which is pretty consistent through here — there are a few that are a little bit longer. Some of the sections might be a little bit thicker, so they might want a little bit longer frack length.

But the key takeaway is that none of these fractures — over 2,200 fracture stimulation jobs — none of them came anywhere close to extending up near the surface or near any surface water.

The shales at Kotaneelee are even deeper than the shales in the Barnett and the water table is much shallower at Kotaneelee than in the Barnett, so the takeaway from this data is that the risk of negative environmental impact due to fracture stimulation at Kotaneelee is essentially zero.

Right now I’d like to move really from the technical aspects to the benefits that come from natural gas extraction in the Yukon — switch gears and talk about the importance of natural gas.

Global demand for energy is expected to rise by 35 percent by 2035 as economies in both developed and emerging countries continue to grow. The trend to generate energy in many areas is moving away from oil and coal fuels toward natural gas. Canada is the third-largest producer of natural gas and Kotaneelee is a world-class gas resource and is currently the only active gas field in Yukon. Essentially the world is moving toward natural gas and Kotaneelee gives the Yukon the ability to produce sufficient natural gas to be energy independent for many years.

Here I’d like to move from the more global perspective a little closer to home and focus on the Yukon. The Yukon Territory is a territory whose economy is driven by mineral extraction. Expensive diesel and limited hydro-generation has been the only options for industrial fuel in the Yukon. Yukon is looking to reduce the use of expensive fuels and reduce the dependency of fuels from neighbouring provinces. Kotaneelee gas could be used as a diesel substitute for industrial markets. Natural gas is less expensive and there is a reduction in harmful emissions. It is safer to transport and store and is less corrosive, meaning less maintenance on the equipment it is run through. Yukon will not need to rely on others for their energy needs.

Yukon’s future industrial landscape will require natural gas to fuel their projects. Natural gas and LNG is the direction companies and countries are heading.

So how do we make this happen? Well, we move toward LNG. Traditional transport methods of natural gas have historically been by pipeline or by LNG tankers for large-volume global trade. Today, natural gas — via LNG — can be safely, effectively and economically transported by truck. This was not feasible just a few years ago. The advantages of LNG from Yukon gas is that this new technology has been established for smaller, economical LNG plants. This fits with what the Yukon needs: small, fit-for-purpose LNG plants.

The ability to utilize the existing roads and infrastructure is exactly what the Yukon needs. It’s too difficult to run pipelines everywhere. All the projects, all the mines, are too spread out to make a pipeline system very effective. There is a reduced transportation cost due to the close proximity to end users. What I'm meaning here is that the Kotaneelee gas gives us the ability to bring LNG much closer to the Yukon, rather than getting it from places like Calgary or Vancouver, which adds a lot of extra expense in transportation. This would entice previously uneconomical start-up operations' potential to reach remote areas — as I've explained — and reduce construction time compared to large plants.

We can do these sorts of plants in months, rather than several years — three, four five years that you hear about for the big projects, things that are being discussed in British Columbia.

This is a solution to Yukon's current and future gas needs. We feel LNG from Yukon gas is by far the best solution for the long term.

Really briefly, what is LNG? LNG is natural gas that is refrigerated and converted to a liquid at minus-162 degrees Celsius. It is a clear, colourless, odourless liquid. It is less than half the weight of water. LNG is safe. LNG in liquid state is not flammable. LNG vapour is flammable — obviously it's gas, but it's not explosive — and LNG is stored and transported in low-pressure insulated tanks. It's not transported under high pressure.

So, supplying the Yukon has the potential and a relatively simple process. An LNG facility could be constructed in or very close to the Yukon. LNG is transported by truck using existing roads and infrastructure; low-pressure storage tanks can be put easily on each location, and regasification facilities can be put on-site. These are all proven technologies.

Here is just a simple pictorial of the process. You start with the wellhead — and this is essentially where the wells are. In a short distance you take it to a liquefaction plant where it's cooled and converted to liquid. It's then transported to a truck, which then takes it to the end user where it puts it in a small storage tank, and it's ready for use. All that needs to be done is to heat it slightly through a vaporization facility — a very simple process — and then it is used however needed, either in power generation or vehicle consumption, or whatever is required.

The key is that the Yukon has this gas today. There are significant opportunities generated by oil and gas operations in the Yukon: job opportunities being technical and non-technical in a wide spectrum of areas and business opportunities — drilling-related services, gas plant services and support, construction, civil works, trucking and pipeline to name a few.

I also want to point out that shale development would be a very big project. We're talking significant capital influx into the area. I would say that, depending on the scale of our project, it could be well over $1 billion. That would be many, many jobs; many business opportunities. It would be a huge impact on the local economy. In perspective, our conventional development will have a big impact, there's no doubt. A shale development would have a huge impact and would be around for a long time.

Natural gas as a replacement fuel will provide added value to other companies and industries that will cause economic growth and trickle-down job creation throughout the territory. This creates a new business model for alternative fuels we call "Yukon gas for Yukon". Job creation through economic growth — this will attract oil and gas industry into the Yukon, further diversifying the Yukon economy beyond the primary mining business of today. Decreased energy costs would encourage other natural resource development and a possible decrease in energy costs for the local Yukon ratepayers. There would be improvement of infrastructure — roads and bridges — that would be inherent in this project and certainly benefits to First Nations and we recognize this. There will be business opportunities, jobs, education and training and increased revenue through royalties and taxes to the Yukon. This would assist with self-sufficiency and creating less dependency on the federal government, giving Yukon significant autonomy. We feel this is very important.

In summary, Kotaneelee has the potential to be a world-class field. The Yukon regulatory regime is extremely robust. Our near term development plan focuses on conventional gas — that's important to understand. Our near term is developing the conventional gas. However, the majority of the gas to Kotaneelee is shale gas. Fracture stimulation will be necessary to extract the shale gas, although as demonstrated, the process of fracture stimulation in Kotaneelee would be conducted safely and responsibly. Kotaneelee gas can provide energy independence for the Yukon and, as I've just explained in the last few slides, the benefits are many and are crucial for Yukon's sustainable growth.

That concludes the presentation. Thank you very much.

**Chair:** Thank you. If you could just indicate who will be speaking next.

Mr. Wyman, please.

**Mr. Wyman:** Good afternoon Madam Chair, members of the select committee and visitors in the public gallery. Thank you for inviting Northern Cross to present to this Committee today and give us the opportunity to provide our views on the important subject of hydraulic fracture stimulation.

Joining Don Stachiw, our VP of exploration, and me are my three colleagues that are working out of the Whitehorse office. Sitting down here — Greg Charlie is vice-president of community and government relations, Cindy Dickson is regulatory environmental and community relations coordinator, and Sam Wallingham is superintendent of our field operations.

In my comments this afternoon I would like to focus on four or five things. First of all, who is Northern Cross? Secondly, how do we conduct our operations in Yukon, where it is that we operate, and what it is that we are doing. I'm going to offer some comments on benefits to the Yukon from our activities and a broader perspective of what the industry itself could offer the territory, and then conclude with a few remarks. So the slide that you see is where our base camp is. It was formerly a work camp used in the 1970s when the

Dempster Highway was being constructed and it is about 325 kilometres from the Klondike corner.

Given the limited time for three presenters, I apologize in advance if I have to rush through this presentation, but hopefully we can pick up the slack in the question period if there is any need for clarification.

Who is Northern Cross? First of all, Northern Cross is a Canadian company. It obeys Canadian laws and Canadian regulations. The majority of directors and management of the company are Canadian citizens and have many years of oil and gas industry experience. Northern Cross was incorporated in Yukon in September 1994, and we have 15 full-time employees, three of which are here in Whitehorse. Recent events — Northern Cross has been involved in a variety of exploration projects at Eagle Plains during the past 20 years. During this period, the company has expanded its asset base by acquiring the interests of other companies, building a portfolio of exploration acreage, expanding our knowledge of the geological opportunities, and purchasing key pieces of equipment.

In 2011, Northern Cross received a major equity investment from an affiliate of CNOOC Ltd. — a very large Chinese national company — and that has enabled Northern Cross to proceed with an ambitious exploration project at Eagle Plains.

In the period from about June 2012 to July 2013, Northern Cross has drilled four exploration wells at Eagle Plains, and we are now underway with a 360-square kilometre, 3D seismic program this winter.

What are our business practices? Northern Cross has worked cooperatively with several Yukon governments since we incorporated almost 20 years ago. We have a long history of participation in First Nation, government and other public consultation processes on issues that relate anywhere between land claim implementation, land use planning, protected areas, industry regulation, and explaining what our projects are all about.

Northern Cross is committed to using best practices in the conduct of its activities, often exceeding regulatory standards.

Northern Cross, over its experience in the Yukon, has met and continues to meet with stakeholders on a regular basis. We host tours for interested community and government representatives to visit our operations. Over the years, Northern Cross has hosted open houses in several communities, such as Whitehorse, Mayo, Dawson, Old Crow and Fort McPherson. We meet regularly with various agencies of the Yukon government and First Nation governments whose traditional territories comprise the exploration lands to provide updates on our activities and our plans.

As a company, Northern Cross prides itself on transparency and honest dialogue with key stakeholders.

Among other things, we are committed to minimizing our footprint. We have a demonstrated track record of using best practices to mitigate the impact of our activities on the environment. We reuse previously disturbed areas, we directionally drill wells to avoid surface disturbance, and we isolate the equipment from the environment by using a combination of impermeable liners, layers of earth and sawdust and thick wooden mats to protect the environment from the impact of our activities.

We also strive to spread out our work as much as we can. Sometimes it's not seasonally available, but to the extent that we can do it and by spreading the work out, it gives longer term employment opportunities and better chances for Yukoners to be involved in our projects.

In the appendix to this presentation — I won't get to it here today — there are a variety of photographs that show a number of the measures I've just described so you can look at that at your leisure.

Northern Cross has also taken a number of measures to manage potential encounters with wildlife. We have First Nation wildlife monitors working at our site continuously, our camp is fenced and we incinerate all waste. Access to the sites off the Dempster Highway is restricted and we have policies in place to restrict activities as necessary to avoid wildlife disturbance. These measures seem to be working because there have been no adverse impacts arising from any wildlife encounters in the last couple of years.

In summary, Northern Cross takes very seriously its responsibility to mitigate environmental impacts as part of its own social licence to operate in Yukon.

So let me talk a little bit about where we're active and what it is we're doing.

This is a map of the Yukon on the left and it zooms in on the right to the area where the exploration permits are located. Northern Cross owns majority working interest and operates three significant discovery licences — the acronym is SDL — that demarcate the only discovered oil and natural gas at Eagle Plain. These SDLs are a legacy of exploration work completed by other companies in the 1950s, 1960s and 1970s. We also have 15 exploration licences that have been awarded since 2007 in the Eagle Plains region. These awards were given to us by the Yukon government on an aggregate spending commitment of $22 million. The licences are all on Crown land, but are within the traditional territories primarily of the Vuntut Gwitchin First Nation but on the east side of the Dempster there is overlap between the VGFN and the Na Cho Nyäk Dun.

The area of the map on the right side that is shaded in pale yellow shows the exploration acreage. In aggregate, it's about 1.3 million acres. The three SDLs are the red and yellow cross-hatched areas. The light green shaded areas are settlement blocks belonging to the Vuntut Gwitchin and the irregular shaped solid purple area is the location where the 3D seismic program is happening this winter. It's situated within a broader area of interest shown in the purple cross-hatch that was favourably screened with conditions by YESAB last year.

Eagle Plains is a lightly explored sedimentary basin with a total of 38 wells that have been drilled between the period 1959 and the present. Most of that activity was between 1959 and 1972.

In addition to the drilling, there was about 10,000 kilometres of 2D seismic data that was acquired and of that Northern Cross either has rights to or ownership of about 4,200 of those line kilometres.

The 3D seismic program that we're underway with right now uses low-impact techniques to minimize environmental impact and this is the first time ever in the Yukon that a 3D seismic program has ever been conducted. Of the wells that have been drilled to date at Eagle Plain, Northern Cross owns eight. They are all suspended, but potentially able to produce hydrocarbons in the future. All of the other wells were plugged and abandoned and Northern Cross has no ownership in these wells.

In terms of the resource potential in the Eagle Plains region, the Geological Survey of Canada has estimated that the mean volume of oil in place to be about 450-million barrels and about 6-trillion cubic feet of natural gas. These measures do not include any resources that might benefit from hydraulic stimulation.

Eagle Plains is the largest oil and gas region onshore in the Yukon. It is a complex sedimentary basin that offers both structural and stratigraphic settings for crude oil and natural gas to be found. At this time, Northern Cross is conducting a resource assessment to evaluate new exploration ideas and fulfill commitments that we made to the Yukon government when the exploration acreage was awarded to us.

Now exploration activities by their nature are a sequence of short-term projects requiring temporary access and are designed to evaluate resource opportunity in a given area. Typical exploration activities include geological field surveys, seismic data acquisition, drilling, fluid and rock sampling and analysis and production testing.

The four wells that Northern Cross has drilled between July 2012 and July 2013 ranged in depth between about 1,000 metres subsurface and 3,350 metres. The results of that drilling program are currently being evaluated.

Northern Cross conducts its activities at Eagle Plains, largely under the terms and conditions of the *North Yukon Regional Land Use Plan* that was approved a number of years ago.

The four wells that we've drilled to date evaluate up to nine different geological opportunities over a pretty broad geographical area, and the program that we're underway with right now to gather seismic data will be concluded probably sometime in April.

So let's talk a little bit about what this exploration program is all about. We are in a fairly early stage. This slide gives you an idea of the time frames involved to go from geological concept through exploration, evaluation, appraisal, early stage development under pilot operations and ultimately to a full development. Typically in a setting like North Yukon it can take a decade or more.

We have not defined sufficient resources to advance to a commercial development yet, but each of the steps that are taken in this slide are designed to reduce the business risk and improve the chances of success. The Yukon is a comparatively remote area with limited infrastructure, so this time frame actually could be optimistic.

Likewise, the time frame to develop any kind of resource is dependent on whether a discovery is oil or gas and what sort of infrastructure is required to process and transport that resource to market. Subject to the results of the 3D seismic survey, Northern Cross anticipates another round of exploration drilling in the future, but the efforts that we are taking right now are presently aimed at finding, evaluating and potentially developing crude oil or natural gas from geological formations that are not expected to require hydraulic fracture stimulation to take place.

Having said that, there is mounting evidence that Eagle Plains do contain geological formations that could be candidates in the future for hydraulic fracture stimulation. But more engineering and geological studies are required to confirm whether or not there is merit to apply that technique so, at this time, Northern Cross does not have plans to hydraulic fracture stimulate and will not be able to make any plans until these studies are completed. The time frame for us to consider hydraulic fracture stimulation is measured in years.

As the exploration work continues, Northern Cross anticipates more YESAB reviews and regulatory processes to take a look at the projects that we propose as we go through this entire sequence of events in the future.

The oil and gas industry is highly regulated in Yukon, like it is everywhere else in Canada. Every activity requires a regulatory review prior to any operating licence being issued and, likewise, all activities undergo frequent inspections by various regulatory authorities in the Yukon.

For example, land use inspectors, water resources, Worker's Compensation Health and Safety are three that frequently visit our operations. The regulatory regime in Yukon has drawn and continues to draw on the regulatory experience and expertise from other oil and gas jurisdictions in Canada, and based on our own experience in dealing with the regulatory regime, it is competent and responsive to developments in other jurisdictions where the oil and gas industry is far more mature than it is here. YESAB screening of oil and gas activities is usually a part of that overall regulatory review.

Let me talk a little bit about benefits. At a macro level there is a significant value proposition to Yukon if a local supply of crude oil and natural gas resources can be developed. The potential benefits include economic diversification, and that is both in terms of establishing an industry with oil and gas production but also the service industry that supports it. It could provide reliable and cost-effective new energy supplies to other sectors of the Yukon economy. It would offer greater economic stability typically associated with long-life assets, and there would be the fiscal benefits of royalty and tax payments and taxation, and the economic spinoff of high-salaried employment.

The combination of the economic multipliers of this activity and the synergies with other industries, such as mining, could combine to have a profound positive impact on the Yukon economy in the future.

The Yukon currently imports around 130 million litres a year of gasoline and diesel for transportation demand. The cost of that imported fuel is about $150 million to $200 million a year. That works out to be about $4,000 to $5,400 per person in this territory, and it represents the annual opportunity for jobs, royalties, taxes and other benefits that are lost to the jurisdictions supplying that fuel to this territory. This information excludes the use of fuel for off-road purposes like heating, power generation and other industrial applications. That means there is a huge leakage to this territory that could be shifted into a huge economic benefit if a local supply is developed.

From that stream of fiscal benefits, there is a revenue-sharing arrangement that Yukon First Nations have with the Yukon government, so the benefits are widely shared.

At a micro level, let's talk a little bit about the impact that Northern Cross has had economically here. We conduct our activities under a benefits agreement in accordance with section 68 of the Yukon *Oil and Gas Act*. Since the exploration program began a couple of years ago, Northern Cross has spent over $80 million and expects to spend another $20 million on the seismic program this winter. Of that $80 million, over $16 million of that expenditure had been for the direct benefit of Yukon-based businesses and citizens. Northern Cross employed 88 different Yukon suppliers for goods and services in that drilling program alone. We are committed to providing opportunities to Yukoners, including Yukon First Nations.

**Chair:** Excuse me, Mr. Wyman. We have about seven minutes left in this time slot. I leave that to you.

**Mr. Wyman:** Okay. I'm getting close to wrapping up here.

That slide is three Yukon citizens working at our site.

Let me wrap up. Although the oil and gas industry has had some presence in the Yukon for almost 60 years, it doesn't have the same familiarity as the mining industry.

Yukon oil and gas regulations are robust and responsive to evolving industry practices and changes to regulations in other jurisdictions. In the right regulatory environment and applying good engineering practices, hydraulic fracture stimulation is a safe procedure to use in certain geological settings to improve resource recovery. It's a technique that is widely used in thousands of wells every year in western Canada with little or no adverse impacts.

Although Northern Cross does not now have any plans to apply this technique, it would like the capability of using it in the future if there's technical merit to its application.

Northern Cross, in conclusion, believes that the benefits of having an oil and gas industry in Yukon more than offset the risks associated with industry activities. As demonstrated in other more mature jurisdictions in this country with proper regulation, like Alberta and B.C., the industry can provide benefits with minimal risks.

On that note, thank you. This presentation is on our website. I think it will go on the select committee's website. There are another 10 slides that give you some visual look at some of these mitigation measures that we actually apply.

**Chair:** Mr. Ferguson, you have about 10 minutes.

**Mr. Ferguson:** Thank you very much. I certainly appreciate the opportunity to be here on behalf of the broader Canadian industry. Recognizing the time, I thought I would get immediately to a couple of key, more specific, points and then certainly be open for any questions or comments later. Given that I sat in on a little bit of this morning's discussion as well, I think it's important to hear from the members themselves who want to operate and are operating in this jurisdiction. I certainly bring a perspective from a Canada-wide, upstream association that has some experience in many of the provinces and territories of Canada.

So maybe I'll just make a few comments in the interest of time around something that I think is pretty important. We heard a little bit today. I just wanted to add to it, around the concepts specifically around fracking. It's really about good planning and design. It is a highly technical process that you've seen and heard from other presenters. I think it's important to emphasize that this is done with a lot of care and attention up front, during the operation and following the operation.

I think the other thing that is important for you to understand is that it's one aspect of a broader oil and gas development process. The stimulation or the fracking process is one particular aspect of the overall process of producing oil or natural gas. All of it is taken into consideration when we go through a planning process to decide where to locate a well first. Probably one of the most important pieces is the location of the well and that is taking into consideration things that you've heard around understanding natural faulting, orientation of the reservoir, what depth we're looking for. So there's a lot of work to be done in terms of location of the well from a subsurface perspective, as well as a surface perspective.

I think, following that, the most important aspect that you will see and hear, and I think hopefully get to as you develop your aspirations for this kind of resource development opportunity, is around well construction. I can't emphasize enough from other jurisdictions that we have experience with that you have to pay attention to that as a foundation element to decide whether or not fracking is safe, possible and you want to see it happen.

That really is some of the discussion you heard today and previously. CAPP kind of has, as a broad association across Canada, helped our members by developing some leading or guiding practices, we call them, for hydraulic fracking. It's kind of an evolutionary thing. We started with some key aspects that we wanted to get across to our members and ensure that they have that consistent side of information across jurisdictions, because every jurisdiction is at a different place when it comes to looking at where their regulations are requiring certain practices.

So we've certainly picked off the water use — water management — element as a key starting point. We have picked up some guiding practices and principles and contributed to some of the work you heard this morning from B.C. Oil and Gas Commission around induced seismicity in the northeast and beyond, so we have some specific practice recommendations for our members on that aspect. It'll be a continuing, evolving process.

But again — and you'll see in all of that material — well construction is the key. Testing the well before you decide whether or not you can stimulate that reservoir is another important key and there are specific requirements and guidelines that you can find in any of these other jurisdictions.

Just in closing — because I recognize the time and the interest in getting some questions — I think I've heard that earlier today as well, the great opportunity for the Yukon to learn from other jurisdictions — and by learning, I mean the good and the bad because, frankly, there are experiences both ways. It's an opportunity, being a newer jurisdiction to heavier activity in the oil and gas sector, to pick the good and hopefully avoid some of the bad.

I'll stop there and hopefully keep us on time and be interested in any questions. Thank you very much.

**Chair:** Thank you very much. At this time the Committee will take a short recess and reconvene at 4:15 p.m. All written questions from the public gallery should be collected by the page by now. Thank you.

*Recess*

**Chair:** We're going to proceed with questions from the Committee at this time. I'm going to ask Mr. Dixon to start.

**Hon. Mr. Dixon:** Thank you, Madam Chair, and thanks to the presenters. The first question I had was, given your explanations of the spectrum from exploration to development to production, when would it be likely — for your various projects, so I guess it would be a different answer for each project — that we would see locally developed Yukon fossil fuel being used in Yukon?

I don't know which — I guess it's a different answer for different companies, but I'm not sure who wants to start.

**Mr. Hamal:** From a planning perspective at Kotaneelee, as we've mentioned, we've had production already. We currently do not have production on-site and we have plans to reinitiate some existing wells within most likely the summer months in 2014 and then initiate the drilling of new wells either late in the summer of 2014 or 2015, depending on when we have our plans complete and when we can get our permitting.

**Hon. Mr. Dixon:** I guess the same question would apply to Northern Cross.

**Mr. Wyman:** We are still in an exploration stage, so there is some uncertainty about outcome when you're in an exploration footing, but in anticipation that the seismic program would lead to more drilling, I would say that the earliest that there would be any kind of production coming from Eagle Plains is probably about two years from now.

That would likely be under a pilot or a production testing kind of phase. In terms of trying to get to a steady state, full-on development, regular production, you would have to go through various regulatory processes to be able to be running fully. That time frame might be three, five or six years out before you're on a steady state kind of a footing.

**Hon. Mr. Dixon:** If Yukon were to decide that using locally produced fossil fuels was in our best interest and that led us to believe that LNG would be the natural choice, how much of the LNG production — and I guess from liquefaction to distribution and that sort of thing — how much of that would be done in Yukon as opposed to having to ship outside of our borders to come back into the Yukon?

**Mr. Hamal:** We are currently looking at that. Obviously, we have the gas that is currently in the Yukon. Our gas ships out of the Yukon and goes into British Columbia currently. We are looking at various areas in which to develop LNG. At this time, it's unclear what the most economic benefit is, and we have all that under study. Our intention is to use as much as we can in the Yukon and certainly with the intent that the product would then all be shipped up into the Yukon.

**Chair:** Mr. Dixon, you have 20 seconds.

**Hon. Mr. Dixon:** That's good for me, thanks.

**Mr. Tredger:** Thank you, Madam Chair and welcome to our guests. I appreciate you coming and talking to the Committee and to the public.

When a company decides to invest in building out a play — drilling, roads, pipelines and other infrastructure — for hydraulic fracturing or for gas and oil development in a region, they have a build-out plan, a forward looking plan as to what their goals are. A company needs to know, or to estimate, how many wells they want to develop in time in order to get a return on their investment and make a profit and the intensity of wells that need to be developed to become economically viable.

This is a question for EFLO and Northern Cross. I understand EFLO may be further along than Northern Cross, but if you can give us some forward-looking statements and some idea of where you might be going and what we, as Yukoners, can expect down the road if things go according to plan, that would be appreciated.

A final part to that is, will this investment higher due to the need to account for issues specific to the North, such as greater distances for transportation, lack of infrastructure and the need to account for permafrost?

**Mr. Hamal:** I may answer the second question first. There is no doubt that there are certainly logistical challenges in working north of 60. So, yes, those logistical challenges typically convert into additional costs. So, yes, I think it is certainly something that we address and look at in how to economically develop these assets.

As far as our forward-looking plans, we are looking in a very step-wise fashion. We plan to start by working on the existing wells that we have and revitalizing them and bringing them back on using the existing well bores — probably looking at two or three wells, like I mentioned we are targeting this summer, is not an absolute guarantee, but that is certainly what we are targeting.

Then from there, we feel with the technical work that we are doing today, we have the potential for one to three conventional Nahanni Formation — the Nahanni Formation has been produced at Kotaneelee to date. We are looking to see how many wells — and we probably wouldn't determine the total number of wells until we actually drilled the first well and maybe the second well. So it is a building process depending on the results that you get and depending on how the geologic formations pan out when you actually go ahead and drill them.

The shale formations that we have at Kotaneelee are above the Nahanni Formation. So we have to drill through the shale as we drill down to produce the Nahanni. When we drill through the shale, we will test and evaluate the shale. In other words, we will get samples and try to understand as much as we can about the shale.

So that is kind of a developing processes that we use so that in the future we will have the best idea and the best information possible to then look at if and how we would develop the shale. As you can see, the shale development comes down the road after we have pursued the conventional and evaluated the shale.

**Mr. Stachiw:** I'd like to draw your attention back to recalling the slide that we showed with the triangle on it to show the exploration and development cycle to explain where we are and how we make our decisions along the way. Typically, the cycle in a normal exploratory sense is upwards of 10 years from concept through the drilling process, the appraisal process and then ultimately into the pilot phase to understand whether or not you have an economic venture to pursue.

Along the way, there are various chances of outcome and various scenarios that would dictate which direction you undertake. In our case, just establishing whether or not we're dealing, for example, with dominantly an oil product or gas product, the Eagle Plain Basin has both products, so determining that would lead you down different pathways.

The other consideration I think that we always have to be aware of is the remoteness of the location and the amount of capital that's required to deploy and to successfully understand what pathway that we need to pursue. We're at a stage where really there's an interaction between collecting reservoir data and information up front to determine whether or not there is an economic opportunity to be had. We go through trying to establish the estimated recoverable reserves through a series of drilling and testing over the next number of years. That's in the backdrop of cost and so we're constantly playing those three components and trying to understand and alter our project.

**Mr. Elias:** I have two specific questions, one for Mr. Hamal and one for Mr. Wyman. I will start with Mr. Wyman first.

In North Yukon we have an approved North Yukon land use plan, and in that plan we have integrated management areas and land management units that are assigned to four land use zones — I guess they are. Can you explain to me how Northern Cross has adhered to the intensity of use within the zone that you're operating in, or can you give me an example?

**Mr. Wyman:** Sure, thanks for the question. The North Yukon land use plan does have limitations on cumulative effects. I think you max out at around one percent of the land mass or something like that. But Northern Cross does its best to minimize cumulative effects and has to date been successful by reusing previously disturbed areas. Specific examples of that would be drilling McParlon A-25 as our first well. That well was situated in an abandoned gravel pit at kilometre 316 of the Dempster Highway. We used the Chance trail that has been in use for more than 50 years for activities similar to what we're doing today. We also have used our camp, which previously was used as a camp when the highway was built, as a place to drill a well. So there are lots of different ways that we mitigate cumulative effects.

Another way that may not be so obvious to those who have limited exposure to the oil patch is to drill wells directionally. Typically a well would normally be drilled straight down from the surface location, but both our wells at McParlon A-25 and Ehnjuu Choo B-73 were directional wells.

McParlon A-25 and Ehnjuu Choo B-73 were directional wells, so the subsurface target in the case of A-25 was about 250 metres to the west of where we were situating the well on the surface and, in the case of B-73, the bottom hole location was about 1.2 kilometres away from the surface location and the entire objective for doing that was to minimize surface impact.

**Mr. Elias:** I'm also thinking about the seismic activity, but I can ask that later.

Mr. Hamal, under the 230 billion cubic feet of conventional gas that has been produced in the Kotaneelee fields, there is going to be resource royalties paid to the Yukon territorial government. Can you provide those numbers to us today about how much royalties have been paid from the Kotaneelee fields to YTG, because some of that money gets distributed to each self-governing First Nation in this territory and so, if you can provide those numbers to us today, that would be great.

**Mr. Hamal:** What I can share is that obviously most of this was before EFLO was involved. However, my understanding is that the royalty total is around $46 million that has been distributed out of the Kotaneelee production. I understand that that includes the federal plus the territorial, and then of the territorial, my understanding is that — whether it is Energy, Mines and Resources or whoever governs that — it has then distributed that on to the various First Nations throughout the territory.

**Ms. Moorcroft:** Northern Cross may have been asked this question before. You will know that Yukon First Nations have taken a strong stand against hydraulic fracturing in their traditional territories. In particular, the real risk to Yukon lakes, rivers and watersheds is of major concern. How do you respond to the deep concerns of First Nation governments, elders and communities about the risks of fracking and large-scale industrial oil and gas development?

**Mr. Wyman:** Thanks for the question. I guess first that we are still in an exploration footing, and so to be talking about impacts of the longer-term activities — it's a little bit premature to be talking about that, other than in very general concepts. We are in regular contact with the various First Nation governments that have a stakeholder interest in Eagle Plain, and we make them aware of what our plans are and discuss what issues arise from those plans and adjust our activities to respond to those issues.

We've done in the past a lot to address concerns that have been raised. We are not going to do anything that would be irresponsible from an environmental point of view.

Without going down the road of what specifically might happen in a hydraulic fracture stimulation — because we aren't ready to even talk about it — it's a bit moot — but what I can say is — and our track record demonstrates it — that we listen to the communities, we are very aware of what their concerns are, and we adjust our practices to directly respond to that. I think if you look at the presentation, especially in the appendix to that presentation, you can see some demonstration of the things that we do within the scope of our current activities that go out of our way to respond to the issues that are raised by these First Nations.

**Ms. Moorcroft:** I would like to ask whether EFLO has anything to add about the First Nations' opposition to hydraulic fracturing in their traditional territories. I would also like to ask you about monitoring of wells. How many plugged and abandoned wells and how many active wells are there in the Yukon-leased Kotaneelee gas field? What assessments have been done for leaks or failed wells and with what results? What plans would you have for dealing with any naturally occurring radioactive materials that you may encounter in wells?

**Mr. Hamal:** Starting with the First Nations, we certainly think a big part of this is communicating and educating and making sure that they understand what we are doing. I'm talking in a general perspective. Similar to Northern Cross, we are not ready to fracture stimulate. We're still in an evaluation process, although we think that it's a very high likelihood that we will head down that path.

We have already started and plan to continue continual talks with First Nations to help them understand what our plans are, what we are doing, and how and why we would not do anything that would be environmentally insensitive.

There's no doubt about the fact that our company, our individuals within our company, would not do anything that we felt was unsafe or environmentally insensitive. I think that's the place where we would start to get them, so that they fully understand what we're doing on their lands and work with them toward resolving any issues that they may have.

With regard to our facilities, we have three existing producing wells, or wells that have produced, and then we have an injection well, and we have a well that had been plugged and abandoned before we took over. Essentially, for the three existing wells, we have a manned facility. We have a plant that's on-site even though we don't have any production right now. We man that facility so that it's monitored at all times. We monitor our wells at all times. We go out every day and monitor the pressures — we have no leaks, let me make that clear. We don't have wells that have failures and leaks. Everything is contained. We have gauges and valves on all of our surface equipment and so forth.

Those are processes that we work within and we follow the regulations, and they are normal standard operating procedures in how we monitor our wells. Whether we're on production or not on production, we are constantly monitoring them.

**Mr. Silver:** I only have a couple of clarification questions on the domestic market. In the EFLO presentation, Mr. Hamal spoke about providing liquefied natural gas to potential mining projects in the Yukon. I was wondering if there was any consultation so far with the territorial government to date on this plan?

**Mr. Hamal:** We have had some very high-level discussions — up until this point, really, conceptual. We have the gas, we think that it makes good sense, we understand the limitations. We have been in contact and certainly monitoring the mining industry and we know that the benefits of lower costs for them could be very beneficial. We recognize that as an opportunity and we brought that to their attention and that is certainly how we are moving forward. It is still early days, and we just think that it is a great opportunity for us, and we think it's a great opportunity for the industries and certainly for the Yukon government.

**Mr. Silver:** My final question before we get to the gallery questions is, how small is too small? This could be to both companies. Would there be enough work if government development permits reduced the market to short-term, domestic-only industry, which serves large mining operations or strains to our current load?

**Mr. Hamal:** In relation to LNG and gas production for LNG, that is part of what we are trying to do — fully understand the demand that is needed. In general, from what we understand, the sole demand for the Yukon at this stage is certainly too small to be something that we would be able to develop our properties for just that. We envision the LNG being a portion of the overall production.

If the demand for gas or LNG in the Yukon grew significantly more, then that certainly could change, but from what we know today — I know we're talking in relative terms so it's a bit difficult and it's early — it's probably too small.

**Mr. Wyman:** The answer to the question is that it depends. In the case of natural gas, you would generally need more resource and more market demand to justify establishing the infrastructure. Natural gas just needs more facilities; it has to be handled in a more complex manner to be able to take it from underground and get it to market. If the scale is big enough, you would probably be looking at a pipeline but, however you slice it, there's a fair bit of facility required both in the field, in the transportation grid and at the end use.

In the case of crude oil, the starter kit to flip the light switch on would be lower. The complexity of handling crude oil from the reservoir to the surface and getting it into a form that can be transported can start off at a much lower threshold. It's conceivable that if our exploration program is successful and it is oil, that would probably accelerate our plans on going down the road of testing, piloting and developing than if it was natural gas.

**Chair:** We're going to start with the questions from the gallery and Mr. Dixon will start.

**Hon. Mr. Dixon:** Thank you, Madam Chair. This question is from Gary Bemis from Whitehorse. How much is your industry going to cost the taxpayers of the Yukon in terms of infrastructure costs, which include road construction, inspectors, well monitoring in the future after abandonment and health care costs, et cetera?

**Mr. Wyman:** I'll start. So far it has cost very little. I have no idea what it would cost in the future because we are so early into this, I can't even tell you what the development might look like. But the cost to date would be the cost of inspectors to come and visit our operation, so land use would be visiting every couple of weeks while we are active. In the last couple of years, land use inspectors have probably been up to our site maybe 30 times. It's a 400-kilometre trip one way. I don't know — apparently $150 of fuel and hours. In the case of other inspectors, they would be less frequent, but it would be relatively minor in comparison to, say, the tax benefits to the Yukon of $20 million sticking in the territory.

**Mr. Miller:** Just to quickly add, let's not forget that governments all over the world invest in infrastructure, regardless of what industry it is, whether it's industrial industry or cultural industries. So let's not forget that, again, government investment in infrastructure creates jobs. With that infrastructure, it really spurs the economy and, henceforth, creates more jobs. When you have an economy that is growing like that, it creates the government revenue many times over and over. Those said revenues go to fund the key social programs, like health care, education and other social services that Canadians from all provinces and territories cherish and which mean so much to the Canadian fabric.

**Mr. Tredger:** This question is from Don Roberts. What are the current factors that limit your operations in southeast Yukon and/or on Eagle Plains? What problems have you encountered and what problems do you foresee in the future?

**Mr. Wyman:** Probably the biggest factors that affect our operation are remoteness. Because there is not significant oil field service business resident here in the Yukon, most of the services and most of the equipment have to come from either northeastern British Columbia or Alberta. So there is a significant cost to having that supply line being upward of 3,000 kilometres.

The second aspect of limitations would be the limited infrastructure at Eagle Plain. We do have the benefit of the Dempster Highway, which facilitates access, but between our camp and the Eagle Plains Hotel — it has only so many beds and so many plates, so you are pretty limited as to how many bodies you can accommodate to undertake any kind of activity. We can only do so much in a given period of time. The third aspect is, with the limited infrastructure for access, there are projects that we cannot do unless the ground is frozen. Sometimes we have to wait to do things only in the winter.

**Mr. Hamal:** We have similar problems as Mr. Wyman has said, primarily around logistics. We talked a little bit about it earlier with Mr. Tredger's question. Even though we are closer to some of the infrastructure in British Columbia and Alberta, logistically we're on the west side of the Liard River, which basically limits our access. There's no way to get across the river. We either have to barge down the river during the summer or we have to go over the river in the winter when it is iced over. For the most part, I would say that the answer for us is logistics, which in turn affects timing and it also affects cost.

**Mr. Elias:** This question is from Angela Sabo from Whitehorse and the question is, where will the fracturing fluid be after fracturing and can it be 100-percent recaptured?

**Mr. Ferguson:** Sure, I'll certainly start — and not from a perspective of knowing the geography that well and the availability of disposal sites or deep-well injection sites in the Yukon. Right now it's probably, I would expect, somehow transported to existing regulated sites and facilities — probably in British Columbia, I would suggest, would be the starting point. There is a lot of work that needs to be done prior to accepting a site suitable for deep-well injection for waste material and that requires a lot more knowledge of the subsurface geology, so I would suggest that that takes a little bit of time and good planning before you go down that road.

In terms of how much material, I would certainly start off by saying that the return part initially from an initial frack job really depends on a lot of the subsurface geology, temperature, chemistry — just how much you get back of what you put in. It varies quite a bit across the country and other places anywhere from 30 to 50 to 80 percent — somewhere in that range — and it's highly dependent on the specific geology. In many jurisdictions, once you have an economy of scale going, you have opportunities for recycling and re-using some of that material, so that's kind of helping the overall system in terms of minimizing the use of other external sources for frack fluid.

At the end of the day, and I think you heard that this morning, at a specific point in time the economics of further treating recycled material — it's beyond that, so you end up having to find a place to dispose of that final material.

**Mr. Stachiw:** We're in the business of gathering data because we are so far upstream in our exploration project, but what I can speak to — and maybe it is important for the general public to know — is it's not always a foregone conclusion that water is the fracking fluid. In fact, hydrocarbon and liquefied natural gas is very commonly employed in the process. Commonly using reservoir fluids that are native to the reservoir and using that as the fracking fluid is the least damaging to the reservoir, which in turn, means that the productivity of the zone is enhanced the best. Introducing a foreign fluid like water and like surface water many times is not the preferred orientation.

I draw the Committee's attention to the Montney Formation, for example, that everybody I think has heard of in northeast B.C. — very, very commonly, hydrocarbon is the frack fluid of choice because the formation is sensitive to putting any kind of water on it and it actually causes the formation to stop flowing.

Answering the question about the recovery of fluids: very commonly building the program and understanding and testing the rock in terms of its fluid compatibility is a very important part of the upfront work that typically has to be done. Commonly, the use of hyrdocarbons as a frack-based fluid results in a much greater production and much greater recovery at the end of the job.

**Chair:** I have a question from Rick Griffiths. What environmental monitoring for baseline data did your companies undertake in Yukon prior to beginning operations here? Where and how are your drilling wastes disposed of?

**Mr. Joseph:** I can speak to the baseline monitoring. We haven't drilled any wells since we have taken possession of the property. As part of our air emissions permit and as part of the regulatory requirements, we have some passive monitoring throughout our site. So our permit requires three locations for passive monitoring for emissions and $H_2S$ and we have seven. That provides baseline data for future drilling that we will be able to use. Maybe someone else can discuss the drilling cuttings.

**Mr. Stachiw:** We've done a lot of wildlife monitoring prior to all of our operations. We constantly have First Nation monitors and report on all of our sightings, and there are well-established mitigation plans associated with interacting with the wildlife.

I can speak to our recent 3D seismic survey program where we took baseline data for both airborne temperature data as well as methane data to establish what the natural methane background of the area was prior to our work.

**Ms. Moorcroft:** I would like to thank all of our presenters before I read the next question here. It's good to have you here today.

This question is from Jannik Schou and it is directed to Mr. Hamal at EFLO. How much have you estimated that remediation will cost when you have completed operations?

**Mr. Hamal:** Since we don't exactly know what all our future plans are, what we have looked at since we have established production in the established facilities at Kotaneelee — there was a study done in, I think, 2010 that addressed that exact issue. The numbers of remediation, which included the abandonment of all the wells that we currently have and remediating the existing gas plant, was approximately — I don't have the exact number — $30 million, if I remember correctly.

**Mr. Silver:** I have a question from Angela Sabo. How would you deal with any radioactive pollution created in flowback and/or produced waste water? How would you deal with any radioactive pollution created in flowback and/or produced waste water?

**Mr. Ferguson:** I can comment from other jurisdictions that you may have heard from earlier. NORMs are generally regulated fairly well, in terms of the testing up front before anything happens with them. There are regulated processes and disposal sites where they are taken and monitored in other jurisdictions. I'm not specifically aware whether there have been any incidents in the history of some of the wells that have been drilled in the Yukon — whether or not the presence of NORMs has been observed or recorded, but it would be a good example of what we suggest, that you look at what other jurisdictions are doing when they encounter NORMs in their processing and what they do to regulate and manage the handling of those.

**Mr. Stachiw:** We have not had any occurrence, neither do we expect any occurrence of any sort of radioactive water. It just would not be normal in a sedimentary basin, certainly within which we are working. What is more common and we were highly sensitized to was the occurrence of hydrogen sulphide or $H_2S$. We take great care and there are well-established practices for monitoring $H_2S$ and encountering $H_2S$. Fortunately, our basin has been proven to be sweet, so we don't even have that issue to be concerned about.

**Hon. Mr. Dixon:** This question is from Sandy Johnston and it appears to be directed at EFLO, but I think Northern Cross may want to answer as well. Where are the critical fish and wildlife habitats in your area? Why do you deem them to be critical?

**Mr. Joseph:** We've had several environmental investigatory studies done at our location. They've done some soil assessments — some water assessments as well — looking to see what impacts the history of our plant has had. The field has been there since 1979, and so there has been continual monitoring and continual assessment of impacts that we may have had to the wildlife and to water tables. What I can tell you is that they haven't found any impacts that have occurred. We do have the Liard River that's close. When I say "close," it's about 30 kilometres away or so. Our watershed does not go in that direction; it comes the other way. It's hard for me to get into a whole lot of details because some of that work is still ongoing and that's work that will occur before we do any drilling or any further development.

**Mr. Wyman:** Thanks for the question. The area that we operate in Eagle Plains so far has been generally along heights of land and fairly remote to any main courses of water. There are creeks that are partially intermittent or low-flow in loose proximity to where we've operated, but I don't think any of our operations have been any closer than maybe one kilometre or two away from them.

From what I know of the North Yukon, the most sensitive fish habitat would be Fishing Branch and that is probably 70 or 80 kilometres west of us and not that easy to get at. For example, when we use water — which isn't very much in a drilling or in our camp operations — on a heavy day, it might be about 15 or 20 cubic metres in those two things, and if we have to make snow to pack trail it might bump up more, but that would be very temporary. Typically our sources of water are the Eagle River — that will be about 65 kilometres north of us. In the summer we go to Glacier Creek — that's about 100 kilometres north of us — and occasionally we would use Fly Camp, which is probably about 40 kilometres away from us and I don't think any of those are critical fish habitat.

**Mr. Ferguson:** I just wanted to add a perspective in terms of future opportunities and in the event that industry develops further in this area. I was listening this morning and I think the Oil and Gas Commission talked about a tactical planning layer to guide the development in those resource plays and CAPP has been broadly very supportive of that initiative by the B.C. government and something similar is starting now in Alberta as a result.

That's where I think you have an opportunity to bring together for broad understanding and guidance of not just fisheries values, but all valued ecosystem components, in a more tactical frame that can guide operations a little better than probably what more strategic land use plans have.

In terms of a future look at where the Yukon may want to go, we would certainly encourage looking at those kinds of tools and ideas.

**Chair:** You have about two minutes left for a question, Mr. Tredger.

**Mr. Tredger:** This question is similar to one I asked earlier, so it may be a very quick answer. It's from Angela Sabo. Are you able to recapture all the flowback and produced water? If not, what will the damage to the water resources be?

**Mr. Ferguson:** Maybe I wasn't that clear last time. I think other jurisdictions that I'm well aware of actually restrict surface discharge of any produced water from any resource play — not just shale gas — and I apologize that I'm not actually sure on what the regulatory requirement in the Yukon is, but that is certainly something to think about. The more responsible operators that I think you have here certainly look at closed-loop drilling systems where everything is contained, everything is managed in a system that does not lend itself to anything escaping into the environment. I think if you ask the questions of the operators in terms of when they get to that stage of drilling, that would be probably be a key expectation. They are some of the things that we promote among our members across the country.

**Mr. Hamal:** I appreciate that.

To top off what Mr. Ferguson said is that certainly, as operator in the Yukon, whether it's drilling where we would have closed-loop systems — we haven't worked out the final details. But that is something that is not even an issue. We contain all of our fluids that we use during the drilling operation, and in the case of any fracture stimulation that would be done and you have any flowback, everything is contained. It comes back. It's never released out into the surface. It is contained, hauled off, injected — it's done whatever — but it is never disposed of on the surface.

**Mr. Wyman:** I can confirm that ourselves. Doing any hydraulic fracture stimulation is some years into the future for us, if at all, but in the drilling operations that we have undertaken in the last 18 months, we employed fully self-contained systems so there was never any chance for anything to be released into the environment. We recycled drilling fluid from one well to the next, and at the end of the operation any fluids were removed and disposed of at an approved site, generally in British Columbia.

**Chair:** Thank you for appearing for the Committee today.

The time for questions has now lapsed. Thank you all to the presenters, and thank you to all the visitors in the gallery. To those of you who submitted questions, the Committee will review the remaining questions and we will do our best to follow up and make sure that they get answered. The Committee will hear more presentations tomorrow starting at 8:30 a.m.

These proceedings are now adjourned.

*The Committee adjourned at 5:00 p.m.*