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REGARDING THE RISKS AND BENEFITS OF
HYDRAULIC FRACTURING

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Chair: Patti McLeod

SELECT COMMITTEE
REGARDING THE RISKS AND BENEFITS OF
HYDRAULIC FRACTURING

Chair:	Patti McLeod
Vice-Chair:	Lois Moorcroft
Members:	Hon. Currie Dixon Darius Elias Sandy Silver Jim Tredger
Clerk of Committee:	Allison Lloyd
Witnesses:	Bernhard Mayer, Professor, Geoscience Rick Chalaturnyk, Professor, Geotechnical Engineering Sharleen Gale, Chief, Fort Nelson First Nation Lana Lowe, Director, Department of Lands and Resources, Fort Nelson First Nation Abul Kabir, Drilling Engineer, National Energy Board Gary Woo, Program Manager, National Energy Board Patrick Sprague, Director, Northern Applications, National Energy Board

EVIDENCE
Whitehorse, Yukon
Saturday, February 1, 2014

Chair: 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, 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 and Minister of Environment, Minister of Economic Development and minister responsible for the Public Service Commission.

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 today concerning both the potential risks and benefits of hydraulic fracturing.

I would like to welcome the visitors in the public gallery and our first presenter of the day, Dr. Bernhard Mayer. Dr. Mayer is a professor of isotope geochemistry at the University of Calgary. His research group has experience with tracing water and contaminants in the Athabasca oil sands region and with baseline analysis of groundwater in Alberta.

Following Dr. Mayer'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 shortly before the end of the 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 best with the time we have 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 onto the public record.

I'd like to remind all Committee members and Dr. Mayer 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.

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

Mr. Mayer: Thank you very much for your introduction and giving me the opportunity to speak to you about assessing the potential environmental impacts of multi-stage hydraulic fracking on shallow groundwater and on surface water.

As you all know, the rapid development of shale gas in Canada and the United States has been driven by the high gas prices earlier in the century and by two technical developments. One of them is horizontal drilling, where wells can now be deflected by 90 degrees and be drilled horizontally for more than one kilometre in shale gas plays, and secondly by hydraulic fracturing or fracking where fluids, chemicals and sand are typically injected to fracture the reservoir for extraction of natural gas or for extraction of oil.

Shale gas development in Canada and also elsewhere is often affected by the public controversy between rapidly expanding exploitation of unconventional oil and gas reservoirs by industry, facilitated by horizontal drilling and fracking, and by the fear of landowners and parts of the public that these activities may have negative impacts on the quality of groundwater and surface water in the area where development occurs.

I thought before we go into detail, I'd show you two or three pictures of what these sites look like. This is a rather small fracturing area where we have a wellhead here — number 3 in the front — and what you see around this wellhead is infrastructure and the trucks that are needed to complete the fracking. At this well, where number 1 is a data and satellite van; number 2 are sand conveyors, there are blenders that mix the sand, the fluids and the chemicals that go into the well. We need pumping units to create the pressure to conduct the fracking. There is a chemical van which delivers the chemicals that go into the well. There is test equipment to make sure that everything is done properly, and in the very back you see water storage tanks that are used for water that is needed for fracking and also for the flowback water that comes back out of the well.

This is a close-up figure showing the wellhead itself which is now rigged for the fracking operation itself. There are lots of pipes here that deliver the sand, the fluids and the chemicals, and this is the machinery around it that is required to create the high pressures needed during the fracturing job.

Negative impacts on shallow groundwater and also on surface water can mainly come from three different areas which should be distinguished. First of all, there is potential for stray gas leakage where there's often methane and other hydrocarbons. There is potential for formation water to come back to the surface and there is potential for fracking chemicals to leak toward the surface — fracking chemicals that are used for the fracturing job.

Now from a scientific viewpoint, there's an astounding lack of high-quality scientific data in the peer-reviewed scientific literature on groundwater in the vicinity of oil and gas operations. The rationale why somebody from a university would be engaged in this area is that we believe that closing the science gap could be highly beneficial for responsible development of shale gas plays in the future.

The objective of my presentation today is to discuss the key components of potential groundwater and surface water monitoring programs that would be suitable to generate scientifically defendable data for testing of impacts, or the lack of impact, of shale gas development on the quality of groundwater and surface water in the developed areas.

The relevant experience we have on that in the Province of Alberta is that since 2006, the Alberta Energy Regulator required a baseline groundwater analysis program for all groundwater wells situated within 600 metres radius from a newly drilled coalbed methane well. These coalbed methane resources are relatively shallow. They are accessed by vertical wells, not horizontal wells. The fracking typically occurs with nitrogen rather than with chemicals so there's a slight difference, but the program that was laid out might be a good example of what could be done to monitor whether impacts occur on groundwater and surface water in the area.

In Alberta, since May 2006, more than 10,000 groundwater samples have been taken and analyzed in the context of this program. Currently the Alberta government is considering expanding this program to shale gas plays, and that is the reason why I would like to tell you a little bit more about it.

If you talk about leakage of gases or fluids toward the surface, we have to first think about what the potential leakage pathways are. This is a cross-section showing you a wellhead, the trucks, the chemicals, the tanks that are at the wellsite. Underneath is a potable aquifer, which is accessed by a groundwater well. This is the energy well that goes through the zone of groundwater protection, down into the intermediate zones. These are geological layers often more than a kilometre thick. Down here we have the well deflected in the production zone where fracking has happened.

So we have to distinguish two different pathways in principle. One of them is that there might be spillage at the surface, and chemicals and other compounds might leak down into the groundwater, but there are very solid regulations and there is good knowledge how to deal with that.

A second leakage pathway — and that's a new one — is the leakage from below, where it could be from the production zone, but scientists are convinced that fracking in the production zone never goes far enough that leakage would occur through the geological column direct to the surface. It is much more likely that if leakage occurs, it would occur along imperfectly sealed wells. That could be either the newly drilled energy wells, or it could be an older well that might be in the vicinity of abandoned or still-producing well, where leakage along the wellbore might occur. So, it's generally accepted that leakage along these wells is one of the major risks in shale gas and shale oil production.

Before I go any further, I want to state that if a well is perfectly constructed and perfectly sealed, there should be no leakage of gases or fluids along the well bore. I also admit that on occasion leakage along wells occurs and I believe speakers yesterday and probably speakers later today will refer to that in more detail.

If one wants to establish a monitoring program for groundwater and surface water, there are really two main essential components that are required. The first one is the key to generate a scientifically defendable baseline prior to drilling and hydraulic fracturing against which potential changes which might occur due to drilling can be compared to. The second component is when to continue with a ground and surface water monitoring program during and regularly after hydraulic fracturing to test for potential detrimental impacts on the water quality.

In devising such a monitoring program, there are really six relatively simple questions one could ask. First of all, which sample should be obtained? How should the samples be obtained? Who should obtain the samples? What parameters should be analyzed? At which location should the samples be obtained and how often should they be obtained? Despite the fact that these sound like very simple questions, the answers are not always simple to obtain. The goal for all of this remains that we want to monitor for potential impacts on shallow groundwater and surface water, either from stray gases such as methane, from formation waters coming from the deep subsurface toward the surface or leakage of fracking chemicals that are used in the hydraulic fracturing job.

If we try to answer some of these questions and start with which sample should be obtained, this first answer is very simple. We need a groundwater or surface water sample. There is a member of our research team who is pumping groundwater out the ground and trying to take a water sample. But we also like to analyze gas samples, because stray gas leakage is one concern and that can only be tackled if gas samples are obtained. Here we already have two options: we can take a free gas sample or a dissolved gas sample.

The difference between the two is shown on the diagram on the right-hand side, where we have on the X axis temperature versus the amount of methane, which is in the water sample in milligrams per litre. Through the diagram, you see a black line that is the line of saturation. What this means is that a certain amount of methane, maybe up to 30 milligrams per litre can be dissolved in a water sample.

We talk of sub-saturated conditions or dissolved methane. Once we have more methane than can be dissolved in a water sample, we will start to develop a free gas phase. Now the Alberta regulator prescribed that only free gas samples should be obtained. So, only if we have more than 30 milligrams per litre of methane in the well would we take a sample.

That is of slight concern, at least scientifically, because you can envision a situation where a baseline groundwater sample had very little methane, maybe two milligrams per litre. When a well was drilled, the fracking job was conducted, we come back one year later and the methane gas concentration has increased by tenfold to 20 milligrams per litre. That is a development that would be missed if only free gas is analyzed.

In our view, from a scientific aspect, we like to do both — dissolved gas sampling and free gas sampling for methane — in order to catch all these eventualities.

This is how the operation works — maybe I will go back for a second — you see a device here on top where water is pumped in, it's brought to the top of this cylinder and dropped down in the cylinder. You can see it a little bit better here where there is a water column in the bottom where water comes out of this hose. Water drops down to the bottom and a gas sample collects at the headspace up here. After that we can attach a sampling device, a little plastic bag in which the gas is taken and brought into instruments that can determine the chemical composition of the gas that comes out of the water sample and the isotopic composition of the gas that comes out of the water sample. The relevance of that I will explain in a few minutes from now.

The second option is to take dissolved gas samples. That is relatively simply done in the field. Here you see how a sampling bottle is inverted. It's filled up completely with groundwater so that no airspace is available. The bottle is sealed and it's brought back to the laboratory. In the laboratory, a little bit of the water sample, about 10 percent, is displaced with an inert gas — in this case it's argon — and the gas in the water sample will now outgas into headspace up here. We can later come in with a syringe, take that gas sample out of the bottle, and again determine the chemical composition and the isotopic composition of the gas that has been obtained.

So we have two options. Free gas sampling is one of them. It's mainly targeted to assure well owners that their groundwater is safe. It's targeted toward risk of explosion in houses. What we have encountered is that different sampling setups may yield slightly different results or, if a different consultant does the work, at the repeat analysis we might not get a comparable sample. So ensuring comparability of results from this free gas sampling is a somewhat tricky issue and requires a lot of care. The dissolved gas sample is a lot easier to do in the field. It's analytically a little bit more challenging because we tackle lower concentrations, but that's quite doable with advanced laboratories. The results are more comparable but they're only representative for samples where they are below methane saturation.

The next question then is, how would we obtain samples? What is widely used in shale gas areas in the United States and Canada is that landowner wells are used for pumping groundwater out of the subsurface and checking the quality of the water sample before and after fracking. There are some issues with that. First of all, some landowner wells are sometimes poorly maintained. But what is a little bit more of a concern is that some of these wells have a very long screen, so they collect water samples from the top of the aquifer, from the middle of the aquifer and from the bottom of the aquifer, and all these water samples are combined and brought back to the laboratory. In cases where redox reactions are happening, that might be somewhat problematic.

There's an example down here that shows you that, as we go deeper into the aquifer, we may encounter different water types. The upper part of the aquifer here is saturated with oxygen and has lots of the dissolved oxygen but it has no iron 2+. Iron 2+ is at zero milligrams per litre. At the bottom of the aquifer, however, I have no oxygen but elevated iron concentrations

If I now take a combined sample of some of the oxidized water up here and some of the reduced water down here and mix it in the bottle, I will enhance a chemical reaction that precipitates iron oxide. I will change the pH in the water sample I bring back into the laboratory, and it will not have the same chemical composition of what's in the field either on top or on the bottom.

Because of that, for scientific purposes, we very much prefer multi-level piezometer groundwater wells, which can take discrete samples at different depths in the aquifer because the chemical composition down here might be quite different to the chemical composition up here.

We also like to place these groundwater wells after aquifer characterizations so that we know the flow path, the flow direction and the flow speed so that we can place the wells downstream of a projected leakage source. Where possible, it would also be nice to not only sample the uppermost aquifers, but to have observation wells that go deeper into what we call the intermediate zone, but currently I do not know of a single site in the United States or Canada where these deep wells have been installed at shale gas sites for monitoring of leakage in these areas.

We now move on and ask what type of parameters we would analyze if we have gas and water samples obtained. Let's start with the water samples, and here I refer to groundwater, surface water, also formation water and flowback water — that's the water that comes back from the shale gas well. There are a lot of standard parameters that every company would analyze. These are field parameters, temperature, pH value, electrical conductivity, redox potential, dissolved oxygen, et cetera. In the laboratory, one would analyze all major cations and anions from calcium, magnesium, sodium, potassium to chloride, nitrates, sulphate and bicarbonate and one can analyze a slew of minor ions and trace metals, such as iron, manganese, arsenic, barium, et cetera, and it's also advised to measure for some organics, such as BTEX compounds and hydrocarbons. C_1 stands for methane, C_2 would be ethane, and C_5 is pentane.

From all this data we can then calculate what we call total dissolved solids. That gives you an idea of what the salinity of the water sample is, and we can calculate an ion balance.

Why is all of this important? It is shown in this table. I'm not sure if you can see it from the gallery, but on the right-hand side there is a typical chemical composition of Alberta groundwater as we find them at 30- to 50- or 80-metre depths. In the middle you see chemical compositions of formation waters within shale gas plays in the United States, the Marcellus play and the Barnett play.

I'm going to turn your attention to this value down here that is total dissolved solids that shows you how saline a water sample is, and clearly the shallow groundwater has by far the lowest values — typically less than 1,000 milligrams per litre — whereas deeper formation waters are much more saline. It could be 15,000 and go up to 75,000 or higher values in milligrams per litre. If some of this formation water would leak back toward the surface, it would be very easy to pick up small amounts of leakage by simply looking at the total dissolved solids.

The total dissolved solids are, of course, a summary parameter of all the dissolved ions. So if you look at the chloride concentrations, they are highly elevated in the formation waters and very low in the shallow groundwater. If you look at sodium, it's the same story: highly elevated in formation waters, low in groundwater. Some of the minor ions, such as strontium, in some plays have very elevated values as shallow groundwater is very low in these concentrations. So it's technically very easy to pick up small amounts of contamination of formation water coming back to the surface by just looking at the simple water chemistry alone.

To show some of our own data from Alberta's coalbed methane program, I will just give you one example in the next slide where we compare the chemical composition of shallow groundwater against formation water from the Horseshoe Canyon formation and formation water from the yet deeper Mannville formation. I should say that most shale plays that are currently exploited in the Montney, Horn River and Duvernay are stratigraphically much lower and hence have even higher total dissolved solids.

These three diagrams are called Schoeller diagrams for shallow groundwater, the next lower formation — the Horseshoe Canyon Formation — and the deepest Mannville Formation. On the X axis you see dissolved compounds such as calcium, magnesium, sodium chloride, sulphate and bicarbonate, and on this axis you see the concentrations in exponential form. If you go up from one to 10, we get a tenfold increase with every step we go up.

The first thing I want you to see is that groundwater has the lowest values, and the deepest formation has the highest values, but on top of that we also get a change of water type.

The water type in the shallow groundwater is mainly sodium bicarbonate. As we go into the deeper subsurface, the major ions are sodium and chloride, so not only do the total dissolved solids increase, but also the water type changes and again we can use that for tracking potential leakage of formation water toward the surface quite easily.

The next few slides are now on the gas composition — gases obtained from surface water and shallow groundwater. Here we have also several chemical parameters which we can analyze. First of all, the gas composition itself — how much methane there is, how much ethane, how much propane, and what else is in the gas samples — CO_2, nitrogen and potentially oxygen.

Another useful parameter we use is the wetness parameter. That is defined as the concentration of methane divided by the concentrations of all the other hydrocarbons such as ethane and propane. So in a sample which only has methane and no higher hydrocarbons, we would get very high values for this parameter and in a sample which has relatively low methane and high quantities of ethane and propane, we would get a relatively low parameter.

Finally, we like to use the isotopic composition — carbon isotope values and hydrogen isotope values of methane and other alkanes to fingerprint leaking gases and determine where they come from.

I assume that not all of you are experts in stable isotopes, so I decided to insert two or three slides to very briefly explain to you what that is. Stable isotopes are subspecies of an element which have the same number of protons but different numbers of neutrons in their nucleus.

If that sounds very scientific, let's look at the next slide here which shows you what we really need, which is carbon and hydrogen, both being compounds of methane. But both of these elements have two stable isotopes, the heavy carbon-13 and the lighter carbon-12 for carbon and the heavy hydrogen-2 and the lighter hydrogen-1 for hydrogen isotopes.

Because these variations in these isotope ratios are a little bit difficult to measure, we have to go into the laboratory and use special equipment and to achieve the highest precision on these measurements, we always measure hydrogen and carbon isotope ratios in a sample compared to that of a reference material. All we do is measure how much carbon-13 over carbon-12 is in a gas sample compared to a reference material and the same for hydrogen isotopes.

The values we get are then expressed in a so-called delta notation, which is expressed in per mil, and all it tells you is whether your sample has more carbon-13 over carbon-12 than your reference or less.

With that explanation we can now move on to isotopic fingerprinting, which is an excellent tool to define and determine whether methane in groundwater comes from near surface environments or whether it comes from the deep subsurface — for instance, shale plays. Why is that the case? Because if we plot these carbon isotope ratios in the delta notation on the X axis versus the hydrogen isotope ratios off the methane molecules, CH_4, then we get quite characteristic patterns. Methane which is formed by microorganisms in shallow groundwater in swamps and peats, typically has very negative carbon isotope and very negative hydrogen isotope ratios.

So the blue areas you see here underneath are all water samples which were taken in Alberta and in the Appalachian Basin from shallow aquifers where the isotopic fingerprint tells us, yes there is methane in the groundwater, but it was produced by microorganisms in near-surface environments.

If we go deeper down into shale gas plays or conventional gas plays, it turns out that the isotopic composition of methane has a very different isotopic fingerprint. We talk about thermogenic gas here that is methane produced, not by microorganisms, but by high pressures and high temperatures in the deep subsurface. This thermogenic methane typically has much higher carbon and sometimes also much higher hydrogen isotope values. So methane from the Barnett Shale play would have an isotopic composition sitting up here and if methane with this isotopic fingerprint would invade the shallow groundwater, we would get a very significant trend, which will alarm us if this is occurring.

Isotopic composition of methane in various shale gas plays typically plot up here — very different from a biogenic methane in the groundwater, so we think this is an excellent tool to determine what the source of methane in a certain area in groundwater or surface water may be.

To show you how this works, these are some data from our Alberta groundwater monitoring efforts. These are water samples which were taken between Edmonton and Calgary during coalbed methane production. These are shallow groundwater carbon isotope values of methane and they are all plotting at quite negative ranges between minus 60 and minus 80 per mil.

These are data from the underlying Horseshoe Canyon formation, which has the coal seams in which methane occurs. The methane in the coal seams has a slightly different carbon isotope ratio of minus 52 per mil. If it were this methane which had intruded into the aquifers between Edmonton and Calgary, we should see values around minus 52, but we don't. So this is a good example that we can distinguish deeper methane with higher carbon isotope values quite easily from natural biogenic methane, which may occur in various groundwater and surface water environments.

I also mentioned before that another parameter we can use is the wetness parameter. That is the concentration of methane divided by the concentration of ethane, propane and other hydrocarbons. The wetness parameter is here plotted on the Y axis versus, again, the carbon isotope fingerprint of the methane, which was obtained from various groundwater and formation water samples.

This is again the example from Alberta, where it turns out that groundwater methane — methane in groundwater occurring naturally — is of biogenic origin because it has highly elevated wetness parameters and very negative carbon isotope values. As we go deeper down into the subsurface, at about 500 metres in depth, we encounter methane with lower wetness parameters and higher carbon isotope values.

If we go even further down into the Mannville formation, we get thermogenic methane, with yet higher carbon-isotope values and lower wetness parameters. Most shale gases in this spot are very different from the biogenic natural methane in groundwater.

Again, using the wetness parameter and carbon isotopes, it would be relatively simple to fingerprint whether some shale gas is leaking accidentally through whatever pathway toward the surface, and we can pick up these leakage environments using these isotopic and chemical tracers.

Now in order to do that most exactly — it is important if you want to detect the exact source of stray gases — we not only need to have a baseline sample for the groundwater to see whether there was methane in the first place and what its production formation process has been, we also like to see methane analysis in the production formation from which shale gas is produced and from mud logs.

Mud logs are mud which come back once an energy well is drilled and here in this example you see carbon isotope values for methane, for ethane, for propane and for butane. These isotope ratios were determined as the well was drilled from the surface down 200 metres, 400 metres, 600 metres and further down. What you can see is as we go deeper into the subsurface the methane has very characteristic carbon isotope values which are very low on the high end increasing to higher values below — same story for ethane, propane and other hydrocarbons.

Why is it important to have such mud log data? It is the ingredient you later need to find out where potential leakage of methane and other gases may come from.

This is data from a colleague of mine — Karlis Muehlenbachs, who teaches at the University of Alberta. All he plotted here is carbon isotope fingerprints for methane on this axis, for ethane on the Y axis, for ethane on this X axis and for propane here.

This is an example from Alberta where three water samples, which I encircled here in red, have been obtained and the carbon isotope fingerprints of methane, ethane and propane have been analyzed. The formation from which gas is produced in this area has quite a different isotopic fingerprint; it sits up here.

So Karlis Muehlenbachs was asked to figure out from where the leakage may occur. As I mentioned earlier, there may be leakage along the wells, but it can come from a production zone — but it could also come from an intermediate zone, where sandstone is in between where methane occurs, and maybe it's this methane leaking along the percolation along the well construction either into the aquifer or into the wellhead.

Having done the mud gas sampling from methane, ethane and propane — so these are similar data I've shown you before, where we have the lowest carbon isotope value at the top and we go to higher values at the bottom, the water samples you have seen on the previous slide only fall on one depth where they hit all three curves. So these were the three water samples you have seen in the previous diagram.

It turns out, doing this type of analysis allows us to fingerprint that the gas leakage must occur here in 500-metre depths, which is about 150 metres higher than the production zone. So this tracer technique allows us to say that leakage occurs, yes, but it occurs from an intermediate zone and not from the production zone, and if the shale gas company wanted to go in and remediate and fix this well, it would now exactly know where to go.

The last point I want to address is the fracking chemicals, which is often a mix of fluids, chemicals and sand that is used to fracture the well. Here is an approximate distribution. About 90 percent of what goes into the well is water, most often. Then there is sand, about nine percent. The remaining one percent is a mix of all kinds of different chemicals, which are sometimes disclosed and sometimes they're not.

This is a table that summarizes in principle what kinds of chemicals are used. I don't want to go into much detail on this because each frack is somewhat different. Only some of them are water-based. Others are done with nitrogen, CO_2 or propane. The chemicals that are used will vary from gas play to gas play and if we wanted to monitor for leakage of these fracturing chemicals, there are some ingredients we would pick up with our regular water chemistry analysis I mentioned before.

For instance, ammonium might be in the frack chemicals and an increase in ammonium in your flowback water might indicate some of these chemicals coming back. Potassium is another one; sulphate is another one. However, one point I want to make is that unless spilled from the surface, fracturing chemicals will be introduced into shallow aquifer with the flowback water. It is impossible to bring from the subsurface the chemicals back without the saline flowback water. I showed you before that it's very easy to monitor for saline flowback water contamination in shallow aquifers and in surface waters.

So because of that, I think it's sufficient to monitor for flowback water intrusion into shallow aquifers and surface water first and only if flowback water is detected as a problem, then go further and look for specific fracking chemicals that may contaminate shallow groundwater or surface water.

The potential parameters for regular monitoring that may indicate impact of fracturing chemicals are some of the cations and anions I just mentioned: ammonium, potassium and sulphate. Another one could be total organic carbon — a bulk parameter that shows where organics contaminate the water and possibly selected organic compounds such as BTEX or glycols.

So once the impact of fracturing chemicals on shallow groundwater is suspected, then one can go in and do a lot more detailed analysis for all kinds of different compounds that are sometimes difficult and expensive to analyze for and for their degradation products, but without saline water contamination, I wouldn't even start looking for those.

Two more questions we haven't tackled yet — the next one is where to obtain samples. In order to decide where to obtain samples, it's again important to be clear about your leakage pathways. From the surface, we already mentioned there might be leakage in shallow aquifers or into surface water, but it's very commonly known how to deal with that. From the subsurface, most scientists are convinced that the most likely leakage pathways will be along the shale gas wells, potentially offset wells or potential abandoned wells, which have been drilled many years — or even decades — earlier.

The question we are often asked by regulators is, what kind of testing radius should we have if there is an energy well drilled horizontally in a shale gas play, and we have landowners on top who have groundwater wells 400 metres, 600 metres, 800 metres or 1,000 metres away?

It's very difficult to answer this question without a proper aquifer characterization. If your energy well is upstream and you have downstream flow of your groundwater in this direction, yes, your observation or groundwater testing well should be in that radius. The distance and even the direction of impact may be different for stray gases and for formation fluids. For landowner wells, distances of 600 metres to half a mile have often been used, but none of that has been decided on solid scientific data because it is inherently difficult to do that without understanding the flow paths in the aquifers. For newly installed wells, scientific sampling wells properly selected downstream in the aquifer would be the best to install.

I'll also show a couple of offset wells, because what we have to keep in mind is that the wellhead might be sitting over here, but horizontal drilling might go one, two, or even more than two kilometres in one direction. If there is an older offset well or an abandoned well, the landowner, who has a groundwater well, probably wants his groundwater tested as well.

Finally, how often should samples be obtained? That depends very much on the scientific objectives. The minimum sampling frequency is yes, you need a baseline. Without a baseline, it's very difficult to assess later impacts, whether they are true or not. Sampling during hydraulic fracturing would be good and then sampling after hydraulic fracturing at various time spaces. Leakage may occur many years after the well construction and hydraulic fracturing, so a long-term monitoring program would be highly advised from a scientific viewpoint.

In conclusion, I think I have at least tried to convince you that it is feasible to develop groundwater and surface water monitoring programs that are suitable to generate scientifically defendable data for testing of impacts or testing whether there are no impacts of shale gas development on the quality of shallow groundwater in aquifers and also on surface water. In order to do that, there is a lot of commitment required. Establishing such a program requires a willingness to design a scientifically sound monitoring program. It requires collaboration between industry, academia and regulators. It requires sufficient funds to conduct this task thoroughly for a fairly long period of time and a long-term commitment to maintain the program over many years.

However, if all of this is done, I think there are several beneficiaries: benefits for the regulators who are responsible for ensuring landowners and the public that the groundwater quality and surface water quality is protected; a benefit for industry, which will have data on groundwater quality that demonstrates the extent of impacts on shallow groundwater; and finally the public, that will be assured that scientific data is being collected that is suitable to monitor the quality of its freshwater resources in shallow aquifers and in surface water environments.

With that, I will thank you for your attention and I'm happy to answer any questions.

Chair: Thank you, Dr. Mayer. The Committee will recess for 10 minutes and then we'll reconvene to go through some questions for you.

Recess

Chair: We are going to start with some questions from the Committee.

Our first questioner will be Mr. Tredger.

Mr. Tredger: I thank Dr. Mayer for his presentation and I welcome the Yukoners to the gallery and, to those who are listening by radio, thank you for your attention.

Dr. Mayer, you said in your report that there was an astounding lack of high-quality independent scientific data on groundwater quality in the vicinity of oil and gas wells. Could you elaborate on that and why, and what implications does that have for us as we are considering how to recommend around hydraulic fracturing?

Mr. Mayer: Yes, this is an observation one can make if you go into a scientific database and look for scientific studies about contamination from oil and gas. If you do live downstream from gasoline stations that may have a leaky tank or something like that, there is a lot of regulation of what needs to be done: what needs to be analyzed, how long the site must be vacant before it can be reused. There is a lot of activity, a lot of scientific studies done on this kind of thing. If you go to the upstream oil and gas industry, this type of groundwater monitoring is not mandated. So industry operates at their sites without scientific investigations going on at the same time, unless industry brings scientists in to do so. So a review of these scientific databases yields maybe 10 or 15 studies around oil and gas wells where potential spillage may have occurred, and scientists have done a thorough study investigating those. This is just the way things have proceeded and that's the current status quo.

So in terms of your decision process, I think it means that there are various claims out there from industry saying we can seal wells and there is no issue in the groundwater. There is very little scientific study whether that is indeed the case or not, so what it means is there's a considerable amount of uncertainty about some of the claims that are made in this realm.

Mr. Tredger: How much control does the scientific community have in determining the parameters of their studies, given the fact that they need access to sites and industry controls that?

Mr. Mayer: The parameters we like to analyze are entirely in our control as long as we have enough scientific funding to pay for the analysis we want to do. Site access is a critical issue. If you don't have access to sites or access to data from the oil company about production, flowback water chemistry; about gas compositions, then it's a lot more difficult to do these studies. That is part of the reason why you'll find so little published about it.

Mr. Tredger: Is there anything being done to alleviate that? We hear from the regulators and from the industry that they're open and transparent and more than willing to have their books, as it were, examined. Is that changing and what recommendations can you make to the Yukon to ensure that we do have access?

Mr. Mayer: I think there is recognition that things should change, that academia, that the regulator and industry should work jointly on these issues. In the United States, there is currently a large study being conducted where industry works together with regulators and various universities to test claims whether leakage occurs, whether it occurs or not, et cetera, et cetera. So I think progress is made.

In Canada, I believe all of this is in the jurisdiction of the provinces and I believe a territory like yours can step up and make the regulations such that good baseline data are taken at the beginning and that the role of potential development is done responsibly.

Mr. Elias: Thank you, Doctor, for accepting our invitation to come to the Yukon.

I have a couple of questions here. One is, obviously geochemistry is a very specialized scientific field and, in our work, we've talked to a lot of citizens and industry and regulators, and it seems to me that, if we can develop an isotopic fingerprinting kit, system or program that can benefit citizens, industry and regulators to — what's the word here? — to prove without a reasonable doubt whether or not contamination of drinking water or aquifers was either naturally occurring or done by hydraulic fracture stimulation, it would benefit everybody. And I think that if we develop a program of where to sample, how to sample and what to sample so that everybody can use this kind of thing, it would benefit everybody.

What's your opinion on that? I'm basically seeking an opinion, because it seems to me that this fingerprinting could be really important, especially around areas where there are lots of people.

Mr. Mayer: Yes, the purpose of my talk was not to give you too much detail about what exactly the techniques are we use, but to convince you that there are techniques out there that allow you to test whether saline water from a formation in the subsurface comes to the shallow water environment and whether gases leak. So I believe the tools do exist. They have to be adapted to each different shale gas play, because not every play is the same, so we have to adjust the technology. The technology exists. It's not completely simple to rule out these things. How you sample, where you sample, who samples requires quite a bit of thought so that the data that is collected are comparable at the end.

Yes, chemistry provides at least one aspect with which you can test whether problematic issues occur or whether they do not. The isotopic fingerprinting, if you do it well enough, may even give you ideas at what depth leakage occurs, so if a problem well needs to be fixed and remediated, the operator has an idea how to do it and where to do it.

Mr. Elias: Obviously this hydraulic fracture stimulation is an emotional issue North America-wide, and the Yukon is no different. In my talks with Yukon citizens and my constituents — having coffee with them, or whatever — they ask me, “Well, didn’t you watch *Gasland* and *Gasland Part II*?” I said, “Yes, I did.” They seem to always compare what’s happening in the Barnett Shale in Texas, the Marcellus Shale in Pennsylvania and the McLure Shale in California to our Besa River Shale in Liard and the Horn River Shale in northeastern B.C. or the Canol Shale in the Eagle Plains. In terms of who owns the surface and subsurface of the land and the depths of the water aquifers and the way that they flow and the shale plays, I don’t think it’s a fair comparison, so can I get your opinion on that as well?

Mr. Mayer: Fracking has been used since the 1970s in vertical wells, but not to the same extent it’s now done in horizontal wells.

My opinion is that if an industry rolls out a program in a responsible way — that means there is enough time allowed to do baseline analysis, there is a lot of oversight of how the wells are drilled, there is a lot of testing of whether the wells are leak-tight — then my belief is that shale gas development can be done responsibly. However, if a rollout is extremely fast, if not enough testing is done, if no groundwater/surface water baseline data is obtained, then it becomes very controversial later on to assess whether impact has happened or not. So a territory like yours, which hasn’t started the development, has all the cards in hand to come up with regulations so that things you have seen in some of the *Gasland* movies do not occur in this territory.

Ms. Moorcroft: Thank you for your presentation, Dr. Mayer. I don’t believe that our question period is going to be long enough to ask all of the questions that come out of it, but I’d like to start with questions related to the lack of baseline data and your statement early on in your presentation that there is an astounding lack of high quality scientific data in the peer-reviewed scientific literature on groundwater quality in the vicinity of oil and gas wells.

Can you comment on why that is and how that could be fixed? How do you determine the impacts of fracking on ground and surface water areas where the hydraulic fracturing has been carried out without baseline data?

Mr. Mayer: It’s a number of questions. I hope I remember all of them.

The first question about lack of scientific data around oil and gas development is simply that it was never mandated in a regulatory regime in Canada or the United States. Industry often believes and claims that there are no detrimental issues so there is no study required, and if industry doesn’t provide site access then it is difficult for scientists to study these aquifers in these areas.

Was the second question on lack of baseline data?

Ms. Moorcroft: How do you determine the impacts of hydraulic fracturing on ground and surface water areas where it has been carried out without baseline data?

Mr. Mayer: For some geochemical data there might be groundwater surveys that characterize larger aquifers, or you may have a reasonable sense of what the water quality might be in these areas. What’s typically not done on a regular groundwater survey is the carbon isotope fingerprints of the gases — the methane, the ethane.

With that lacking, one can assume that potentially the baseline groundwater was not impacted by thermogenic gases and if, later on, thermogenic gas shows up in the aquifer, one can hypothesize that it must be from deeper subsurface leakage pathways. But again, if the baseline data is not there, it is very difficult to make with proof because some of this thermogenic gas in some areas may percolate naturally to the surface environments. That is the reason why we insist that good baseline data must be obtained before any development happens.

Ms. Moorcroft: I am interested in your views on how much time you think would be needed to develop a comprehensive and reliable baseline picture. Here in the north there may be specific issues such as permafrost and seasonable variability. How long do you think is needed to collect baseline surface and groundwater data before any development such as hydraulic fracturing would occur?

Mr. Mayer: I suspect it wouldn’t be more than one or two years at the most. Surface water samples can be obtained routinely in an area in the summertime. Groundwater access may be more difficult, especially up here in the north. But what we recommend is that groundwater monitoring wells are drilled on projected pads that are used for horizontal drilling later on, and that a baseline sample is taken before the drilling even starts — so implementation of shallow groundwater well-drilling in the summertime, taking two or three different baseline samples over two or three months, and then development may proceed.

Mr. Silver: I have just a couple of qualifier questions. This is the second time that we’ve had a presentation from you and we’re still trying to catch up with the science part of it.

When it comes to the geothermic component — methane versus the biogenic methane — what are some of the natural causes that would produce geothermic methane to be present closer to the surface?

Mr. Mayer: Thermogenic methane production requires elevated temperatures and elevated pressures that are only found at depths of more than 1,000 or 1,500 metres and further down. The formation of this thermogenic gas has to happen in the interior of the earth, several hundred metres below ground surface. There might be fracture zones, fault zones, in some areas — potentially river valleys, paleovalleys — which create permeability by which some of this thermogenic methane may percolate naturally to the surface. Some of these surveys have been done in the United States, for instance, where along a fault zone, thermogenic methane has been identified as naturally percolating to the surface, and these are certainly areas where good geological site selection would stay very far away if shale gas or shale oil development were to occur.

Mr. Silver: Would extended periods of exposure to different surface depths change the isotopic fingerprint of methane? If geothermic methane was leaked to a top water aquifer per se and sits there for years, does that make it a different — as opposed to C_{12} — fingerprint?

Mr. Mayer: There are a couple of processes that may change the isotopic fingerprint of the gas that seeps from the subsurface to the surface.

One of them is methane oxidation. If methane is oxidized, that means it's removed so that would be one advantageous process, but it changes the isotopic composition somewhat. But again, we have tools to figure out where the methane oxidation happens by looking at isotopic and chemical fingerprints. So I don't see this as a tremendously problematic event or issue.

Mr. Silver: I guess the only other question I have would be observation wells — are observation wells regulated anywhere in North America and if so, at what depths?

Mr. Mayer: To my best knowledge, they are not regulated. The observation wells that most jurisdictions use are simply landowner wells and they are built in different depths, different vintages and different completions. Scientific wells are also not regulated, but there are certain well types which are used by a large part of the community.

Hon. Mr. Dixon: Dr. Mayer, you discussed three potential pathways that either a formation of water, fluids or gas could travel to the shallower depths and aquifers along the well bore, along a legacy or along an offset well. As well, you discuss the possibility of seepage through from the production zone into the shallower depths, but you indicated that — and I think the quote was that other scientists are convinced that that pathway wasn't likely. Can you explain why you think the wellbore or the offset wells are more likely than seepage through the cap rock and through the other geology into the shallower depths?

Mr. Mayer: If hydraulic fracturing is conducted in several cases, scientists use microseismic tools. These are earthquake measurements at very low-intensity scale to assess at which distance from the frack site these small earthquakes do occur. So we talk about magnitude minus 1, .01 — very low intensity earthquakes — which are caused by fracking itself. Most of the data show that the distance from the well is typically less than 200 to 250 metres, so permeability may be generated in that distance from the well, but if a well is two to three kilometres deep, that is certainly not enough to make percolation of fluids or gases toward the surface possible.

Also the companies have no intention — fracking is not a cheap exercise — to frack outside a reservoir, because it has detrimental impacts for your operations. That is the main reason there's fairly solid data that these fracks do not extend in most of the cases by more than 250 metres from the wellsite, which leaves you with another 1.5 to two kilometres of sedimentary or other rocks on top of it. If there are no major faults and fractures, then it would be very difficult to generate percolation of fluids and gases through that rock pile as opposed to potentially leaking wells.

Hon. Mr. Dixon: You've discussed a number of ways to detect whether or not contamination from any of these various sources has occurred in an aquifer or in groundwater, but once that contamination is detected, isn't it then too late? I mean, once you have that contamination, isn't that then too late? What can you do about it then? I mean, it's all good to know where it's coming from, but once the contamination has occurred, isn't the groundwater then contaminated?

Mr. Mayer: You have to differentiate contamination with what — in our research group, we're firm believers that the highest risk is contamination with stray gases, mainly methane. It's a lot less likely that highly saline formation water will percolate to the surface, and even less likely that fracking chemicals will come with it. It has to have saline waters first to have flowback water coming to the surface.

If you go back to the most likely case of buoyant gases coming back to the surface, in the case of methane, groundwater is comparatively resilient. There are processes in the groundwater that can oxidize methane and there is natural attenuation in many aquifers which does take care of some of these contaminants. We have not done enough studies to determine in which aquifers methane oxidation is happening fastest, how long it would take to oxidize the methane, how long the flow path must be and what type of redox conditions must occur. But the fact that methane comes into the groundwater doesn't mean it stays there forever. There are degradation processes that can oxidize and can get rid of some of these contaminants.

Chair: We are going to move on to some questions from our public gallery and Mr. Tredger will lead us off.

Mr. Tredger: Thank you, Madam Chair. This question is from Sandy Johnston.

Why does industry continue to deny any contamination of water when there are many reports of contamination by thermogenic methane and surface spills and fracking fluids?

Mr. Mayer: That would be a question for industry, I would guess. I think denial is a simple solution to not doing much.

We have conducted a groundwater survey in Alberta for several years and we have not found widespread evidence that thermogenic methane leaks into the shallow groundwater all over the place. So I believe there are sporadic issues. There are certain cases where this may happen, but it is not happening on a regular basis all over the place.

Why industry deals with these issues as they do — that is not a question I can answer, unfortunately.

Mr. Elias: This question is from Robin Gilson. There are a number of questions here, and I will try to amalgamate them.

When you do baseline testing, prior to drilling and fracking for biogenic methane and thermogenic methane, both of these specifically, do you also test for glycol, benzene and other hydrocarbon chemicals? And how often do you do the baseline testing after a frack job has been done?

Mr. Mayer: Well, there is no straight answer to this. We in our research group do not routinely test for benzene and other organic hydrocarbon compounds; it could certainly be mandated if required. But if there was no industrial development in that area, it is highly unlikely to have these compounds encountered.

Of course one can expand the baseline parameters that are analyzed. With every parameter you add, of course, the cost goes up and it's a question of how much money you want to spend on testing about everything you could potentially find. If there was no previous industrial development, then chances that some of these anthropogenic compounds are occurring in the groundwater are essentially zero and hence, testing may not be necessary.

Testing after fracking — there is no mandated time frame in most jurisdictions. The Alberta regulator put the onus on the well owner so there was a baseline testing program that established a baseline, and then the landowner who owns the groundwater well has to phone in and say, "I suspect there is contamination in my groundwater well" to trigger a reanalysis. So that's Alberta-specific — reanalysis is only done if a well owner requests it.

From a scientific viewpoint, I would test two or three times in the first year after fracking. After that, if nothing was found, maybe every three years; maybe every five years.

Chair: The Chair has a question from Jacqueline Vigneux. Do you believe casing will last and protect forever and how does the oil and gas industry proceed to fix a leakage two miles underground when it has been capped?

Mr. Mayer: Well, thankfully we have Rick Chalaturnyk speaking next, who is an expert on well completions. I only have second-hand information. This is not my scientific field of research, but I certainly have seen data that some wells after completion have leakage issues. It's a very small amount of newly drilled wells. As wells age — say 15, 20, 30 years — the cement is not going to improve with time, so leakage occurrence will probably increase with increasing time.

I think I've demonstrated today that we now have tools that allow us to fingerprint if gas has leaked to the surface and from which depths they do occur. That is highly valuable information that can be given to the operators to recomplete their well at the very point where leakage does occur.

So there are remediation opportunities. They are probably quite expensive. It costs money to do them, but a leaking well in many cases can be fixed and remediated if the company knows about it, knows where it is and is willing to spend the money to fix the leak.

Ms. Moorcroft: This question is from Jacqueline Vigneux and it is whether there should be water completely tested for both thermogenic and biogenic methane before suggesting any drilling of wells in Yukon.

Mr. Mayer: I didn't catch the first sentence. Can you say that again please?

Ms. Moorcroft: Should the water be completely tested for both thermogenic and biogenic methane before suggesting any drilling of wells in the Yukon?

Mr. Mayer: We do recommend a baseline test and the baseline test in many areas may simply detect that there is no methane at all. We don't have methane in all aquifers. It could be very well the case that there is no methane to begin with. If there is methane occurring, we would like to know how much it is in terms of milligrams per litre and how it was generated, that is with the distinction between biogenic and thermogenic gases. Yes, these tests should be done as a baseline occurrence in all areas where development is planned.

Mr. Silver: You may have answered some of these parts of this question already. This is an anonymous question.

What ground and surface water baseline data do you believe needs to be gathered prior to oil and gas development? Without baseline data, can you still learn if water has been polluted from gas plays?

Mr. Mayer: Without baseline data, we can still detect whether potential contaminants that are in the formation have migrated to the surface. Just on legal grounds, it becomes very difficult to defend that these compounds have not been there in the first place.

Hence the baseline analysis will give you a pristine starting point as to what the water quality may be, before industry moves in and then if repeated analyses are done with the parameters I've shown — chemical composition, maybe BTEX, dissolved gases, isotopic fingerprints, other gases — then it becomes a lot more quantifiable as to whether impact has occurred, how much impact has occurred, whether it's from gases, from saline fluids, from other things, and potentially also gives information how that problem could be fixed.

Hon. Mr. Dixon: This is again an anonymous question.

In a jurisdiction with high seismic activity such as ours, where natural faults and cracks go deep into the earth, do you think that leakage could occur without well failure?

Mr. Mayer: It has shown that leakage of gases from the deep surface can occur along faults if the geological conditions are such that such leakage is naturally occurring. These are certainly areas where one should stay away from with gas and oil development, especially if multistage fracking is involved. That is just good baseline site selection that geologists need to do before any development occurs.

Mr. Tredger: My question is from Matt Hutchison from the Yukon Geological Survey.

Please can you explain what the groundwater protection zone (red horizon on an early slide cross-section diagram) and how it is defined?

Mr. Mayer: The red line on my slide was for a case study in Alberta and the base of groundwater projection is the depths underneath the surface at which the groundwater increases in its total dissolved solids — the amount of salinity to more than 4,000 milligrams per litre. So the Province of Alberta has defined "fresh water" as being water that has less than 4,000 milligrams per litre total dissolved solids. As you go deeper into the subsurface, the formation water typically gets a lot more saline. The depths at which we switch from less than 4,000 to more than 4,000 milligrams per litre in Alberta is defined as the depths of groundwater protection where the government has a mandate to protect the groundwater quality.

Of course, we don't have that many drill holes that would detect exactly where this line lies, so this is in many areas a reasonable estimate, but that line of groundwater protection is not exactly defined on where exactly it lies.

Mr. Elias: Another question from an anonymous citizen. You said that there is no leakage along horizontal piping fractures. Can you please cite some peer-reviewed studies that show this statement to be proven?

Mr. Mayer: Along horizontal piping fractures — is that what you said?

Mr. Elias: That's what it says, yes.

Mr. Mayer: I don't think I said that. I mentioned that if you have a completion of a horizontal well and this horizontal well is fracked multiple times, the fractures typically extend maybe 200 to 250 metres above and below, and that is measured by microseismic techniques. There are several publications that confirm that or show this data.

I hope that was what the question was referring to. I don't have these papers with me, but I can refer the citizen to that scientific information.

Chair: I have an anonymous question.

Do you think Yukon should wait and see the results of other places where fracking is happening, when complete studies are out concerning the lack of security?

Mr. Mayer: Well, that is not an answer scientists can give. I think we have room to grow in responsible development of shale gas and shale oil plays with multi-stage fracking. There are several jurisdictions — Alberta is one of them; Colorado is another one — where new regulations have been developed that will make the rollout of these technologies more secure, more testable, so that the claims of no impact versus lots of impact or some impact can be tested. I mentioned before that you are in a very good position when you haven't started yet so you can do your due diligence in baseline analysis. How quickly you want to roll out or engage in this development at all — I think that's a question where you have to weigh the potential environmental impacts — and there will be some — versus the benefit you get from the technology by creating jobs, royalties, et cetera. But that goes far beyond my scientific horizon.

Ms. Moorcroft: I have a question from Sandy Johnston. If contamination of groundwater is detected and becomes significant, how can groundwater and aquifers be decontaminated?

Mr. Mayer: There are certain geochemical parameters and geochemical processes one could enhance to oxidize methane, for instance. It very much depends on what the contamination is and what the contaminant is. So if gases are contaminating, there are things that can be done to oxidize methane, for instance. If there is a significant intrusion of saline water that would degrade the water quality, the only solution to remediate that is to plug the well and stop the saline water intrusion and then hope for dilution so that the contaminated aquifer becomes fresh again.

Mr. Silver: I have a question from Don Rolie. Should not communities be involved in monitoring programs?

Mr. Mayer: To roll out a large monitoring program for a large shale gas oil development, it would be very beneficial to have communities involved in the regular monitoring. What needs to happen is some solid training of the community volunteers so that the samples that are taken are taken in a scientifically proven manner so that the results that come out after two or three weeks, and after $5,000 are spent on analysis, are really comparable — so that we are not comparing apples and oranges. There is a lot of care that must go into taking the samples — for instance, for dissolved gases and also taking other samples — but if there is a solid training program conducted, there is no reason why community volunteers couldn't help out with a monitoring effort.

Hon. Mr. Dixon: This question is from Werner Rhein from Whitehorse. The writing is a little bit difficult, so I'll try my best.

Professor Mayer, you mentioned several times that it is fairly easy to detect contamination and where it's from, so why is this not done? You also must have detected such contamination, so why is the industry denying such contamination?

I think you've answered some of this before, but we'll pose it again.

Mr. Mayer: I think the industry assumes that they do an excellent job in completing wells, sealing wells and preventing leakage from occurring, and if you stick with that belief and you think there is no contamination possible, then it only costs you money to look for it.

We in our research group have not done a tremendous amount of work around these sites, so there is really an open question. I mentioned before that there are very few studies out there about the extent and the rates at which leakage of gases and fluids from some of these wells occur. There is solid knowledge and data out there. I'm sure it will deviate and change from play to play, from company to company, so why this has not been done is probably a simple reason — it costs money. It costs considerable amounts of money to do this well. It requires a workforce of people who go out, take samples, are capable of analyzing these samples and, since most regulators did not mandate that in the past, very little has occurred along those lines.

Mr. Tredger: This is from someone anonymous. If oil and gas development were to occur in the Yukon, would you recommend that we have a lab in-house to deal with testing? What is the cost of such a setup?

Mr. Mayer: There are different types of testing that needs to be done, with relatively simple parameters such as major cations and anions. I would suspect that you have in the Yukon the capability to analyze such samples already. There are more specialized analyses, like the isotopic testing. Setting up such a lab costs at least $1 million. That's the cheap part. You also need to hire experience personnel to operate it.

It's certainly an option to establish all the analytical tools in the Yukon and do the measurements where the samples have been taken, but I don't see any disadvantage to sending them elsewhere to experienced labs in Vancouver, Alberta or Toronto, and having an analysis done there.

The key must be to get the most precise and accurate data, and it doesn't really matter if it's done in the Yukon or elsewhere as long as the data that is delivered is good.

Mr. Elias: This is another anonymous question.

Has your university department, your research, or your work as a consultant been funded in whole or in part by the oil and gas industry?

Mr. Mayer: The University of Calgary receives significant industry funds. My own research group currently has industry funds from three different industry clients.

None of those are related to shale gas currently. The amount of industry funding we get for work in the oil sands, for instance, or in CO_2 sequestration for enhanced oil recovery, constitutes about 15 percent of my research income for my research program. So yes, we do have research funds and we use them to investigate environmental issues that concern the oil and gas industry in order to improve situations and improve or lessen the environmental impact of oil and gas extraction.

Chair: I have a question from Don Roberts. You are listed as one of the featured scientists with the Wood Buffalo Environmental Association. Could you please describe what work you do?

Mr. Mayer: Yes, I can do that. We had financial support from the Wood Buffalo Environmental Association and matched that financial support with the Canadian science foundation — NSERC. The work we did there is tracking nitrogen and sulphur emissions from stacks in the oil sands environment and fingerprint these emissions to see at what distance the emissions would impact the forested environment around the oil sands region. We used a very similar fingerprinting tool with stable isotopes — in this case just for nitrogen and sulphur emissions from stacks — and measured to what extent sulphate and nitrate deposition in the vicinity of these stacks shows the industrial signal to see how big the impact of industry is.

Ms. Moorcroft: I have a question from Tiffani Fraser with the Yukon Geological Survey. Can you explain why H_2S — sour gas — is not associated with shale gas reservoirs? Can it be present in tight reservoirs — for example, in the Montney?

Mr. Mayer: H_2S in the subsurface is typically generated by thermochemical sulphate reduction. In some cases, it can also be bacterial sulphate reduction. In order to create the H_2S, you need a source of sulphate. So sulphate must be present in order to be reduced to H_2S. There are certain layers and certain occurrences in the Montney where H_2S is present. I have not done any investigations as to why it's there and how it was generated. If you have a shale play that has no sulphate in it, no H_2S can be generated. That's the answer as to why, in many shale gas plays, H_2S does not play a role.

Now, if fracking fluids are injected into these shales that are loaded with sulphate — injected into reducing shale gas plays — then the potential for formation of H_2S is there. But the companies add chemicals to prevent that and, in most cases, they do succeed.

Mr. Silver: This comes from Sandy Johnston and I think you've already answered part of this, but the second part is a good supplementary. Are there instances where thermogenic methane can occur at shallow depths due to transmission along vertical fault lines? Could increased microseismicity increase the likelihood of this happening?

Mr. Mayer: We've already mentioned before yes, thermogenic gas has been detected in some near surface areas near major faults. There is one nice study in the United States stemming from the 1980s, I believe, where a major fault has been identified. Gas leakage was determined. It was determined that its thermogenic gas from deeper horizons and that this leakage extended — and I don't know the numbers exactly — maybe 100 to 200 metres from the fault in both directions and, if you go further away, that thermogenic methane disappears.

So site selection, identifying faults and fractures, major faults and fractures, is a key to direct the industrial activity into areas where this problem cannot occur.

Chair: I would like to remind our guests in the gallery to turn off all their electronics. Thank you.

Hon. Mr. Dixon: This question is from Tiffani Fraser with the Yukon Geological Survey.

Can you explain mud gas sampling? Is this done immediately after drilling or can this be done afterward from the well cuttings? Is this done by the operator and do other jurisdictions require this type of sampling and is it publicly available?

Mr. Mayer: Mud gas sampling is something that does occur during the drilling of a well. The well bit goes down into the subsurface. There is drilling mud required to keep fluids moving and to have the drill bits — the rock bits — flow back to the surface. With that fluid, some gases come back to the surface, so capturing this gas is done immediately as the drilling occurs. The drill bit is in 500-metre depths and the mud gases come back, you take that sample immediately and then you capture what the gas composition at 500-metre depths is and this is how these profiles are developed.

Ten years ago, it was very difficult to do that because of the low amounts of gases coming from the mud. Improvements in measurement techniques have now made it routinely possible to at least measure the carbon isotopes of methane and ethane from these mud gases. It has to be done at the time of drilling. If a company were to take a drill core — it's also possible to take core segments into a contained environment and let the gases out-gas. That is a much more expensive way to do this.

Drilling — sampling mud gases is increasingly done by companies for their own purposes, so they understand the subsurface and the distribution of the gases. I'm not aware that many jurisdictions have it made mandatory that this is done in shale gas or shale oil development and that the data must be made public, so a lot of this knowledge resides currently in industry, but it is technically possible and, if the regulator mandates, it could be mandated that in each township one of these mud gas profiles must be taken to have a reference later on where potential leakage might occur and from which horizon. Because most often when gas leakage occurs, it is not from a production zone. It's from zones intermediate, above a production zone and below the base of groundwater protection, that some gas leakage occurs. Without mud gas profiles, it would be very difficult to fingerprint at which depths this happens.

Chair: We have two minutes left in this section.

Mr. Tredger: This is from Don Roberts of Whitehorse.

What should be the lead time in years? Should an area that has never been fracked monitor ground, surface and aquifers for baseline data?

Mr. Mayer: Ideally, well, let's start with the minimum. If development were to occur in the winter, I would imagine that a thorough groundwater sampling and surface water sampling should occur the previous summer.

We do not have a tremendously lot of data to assess natural fluctuation in some of the parameters given, occurring due to air pressure, to seasonality and other things. So if you are in a scientifically ideal world, you would monitor maybe 12 months before the developments, starting in the previous summer, going through wintertime, and then baseline monitoring in the following summer. Then development could proceed. I think that's due diligence. That would give you a very robust baseline data set against with which you can compare potential later impacts from the oil and gas drilling.

Chair: Thank you, Dr. Mayer. Our time has elapsed for this portion. I want to thank all the visitors for submitting their questions and we are going to do our best to follow up with the remaining questions that we didn't have time to ask this morning.

The Committee will now recess for 15 minutes.

Recess

Chair: Welcome 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 to Mr. Tredger's left is the Hon. Currie Dixon, the Member for Copperbelt North and Minister of Environment, Minister of Economic Development, and minister responsible the Public Service Commission.

I'd like to welcome our next presenter, Dr. Rick Chalaturnyk. Dr. Chalaturnyk is a professor of geotechnical engineering at the University of Alberta. He is a member of the Council of Canadian Academies' expert panel on harnessing science and technology to understand the environmental impacts of shale gas extraction.

Following Dr. Chalaturnyk's presentation, we will 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 shortly before the end of the presentation. 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 entered into the public record.

Mr. Chalaturnyk: Thank you, Madam Chair, members of the select committee and members in the public gallery. Thank you very much for the opportunity to speak to you today.

I think that yesterday and this morning, with Dr. Mayer's talk — a highly complex issue, lots of issues and no differential equations yet. I'm not going to have any differential equations either, thankfully. But I thought rather than reviewing many other things, I wanted to speak to a couple things that are involved in the decision-making that I think are buried in the challenges for the select committee and for the people of the Yukon and that has to do with risk — how risk is assessed, wells, and some issues around hydraulic fracturing monitoring in particular and what that says about managing those risks.

One of the things I am going to do is — lots of academics will do this kind of stuff and throw some things on the board, but one of the things I wanted to show with this was that we have had a great deal of background and work done in the world of CO_2 storage. Carbon capture and storage has been looked at for a very long time now — well over a decade on — a very large-scale, including all of the same elements that are spoken about with respect to shale gas — risk assessment, well integrity, well abandonment, faults, fractures and how they behave under injection and microseismicity.

All of those same issues, the same language that surrounds the discussion for shale gas, are some of exactly the same things that have been looked at for CO_2 storage. I want to go to that work a little bit to show you that there are a lot of answers sitting in that literature — a lot of the identified challenges and approaches to looking at this particular problem.

We have had a lot of experience, all the way from one of the largest projects in Canada — the Weyburn CO_2 storage project in Saskatchewan — all the way through to having the opportunity to chair a Canadian Standards Association technical committee that developed Canada's first standard for the geological storage of CO_2 — I'll speak to that really quickly — to the state that it's actually being used now as the seed document for the development of an international standard on the geological storage of CO_2.

Yesterday and this morning, with the Chair's introduction, there was a reference to the Council of Canadian Academies report. I thought it was important to mention where that report sits. The Council of Canadian Academies posed particular questions of importance to Canada, by the government, and the council takes an independent approach to try to answer those questions. In particular, the one major overarching question that the CCA panel looked at is this: what is the state of knowledge of potential environmental impacts from the exploration, extraction and development of Canada's shale gas resources, and what is the state of knowledge of associated mitigation options? These are very challenging questions. It has been ongoing now for two years.

A lot of work has occurred over that period of time. It was a very multi-disciplinary panel, ranging all the way from geology, hydrogeology — Dr. Mayer was also on the expert panel — and petroleum engineering. In particular and of importance were toxicology, ecology, human health, and sociology — the social aspects of shale gas development — very important issues.

The report itself is not meant to provide recommendations. It will speak specifically to the state of knowledge, and that conversation has come up in the presentations to the select committee yesterday and I'm sure will for the remainder of today. It will talk about technology, well integrity and all of the issues that have been chatted about as well: water, air emissions, land, seismic, human health monitoring, research management and mitigation. The website address is hidden, which is obviously a resolution issue. I think these will be posted. I did check this morning, and the panel's actual formal edited report is expected in the spring of this year.

One of the approaches to speaking to the Committee today was this issue about Yukon shale resources. The challenge that you had in your title and the remit about the risks and benefits of hydraulic fracturing is that, in my mind, there is an overarching question that the people of the Yukon need to ask themselves and answer for themselves. Does the Yukon Territory want to exploit the shale gas resource? We've heard about the economic benefits. You heard yesterday from companies.

You have heard from other people. There are lots of slides. There are words. You hear these words a lot. I can't add anything more to them: affordable energy, direct and indirect employment, some energy security into the region, GHG emissions and so on. Those are straightforward things.

The risks — you have heard about them all: air quality, water resources, water supplies, habitat fragmentation. These are all important and are all issues that need to be dealt with in terms of the decision. But the interesting thing about hydraulic fracturing itself is that once you have made the decision, it's important to manage that resource or explore and exploit that shale gas resource, and you need to hydraulically fracture. It is a resource of a particular quality in nature and it needs hydraulic fracturing in order to actually recover that resource.

So it becomes an issue of managing those risks — putting in place the regulatory policy and regulatory frameworks that allow you to manage those risks.

One of the things on the line of managing those risks that I did want to mention because it was brought up a little bit yesterday is that I think it's important to know that this kind of work is happening in the Yukon Territory. This issue about water balance, water budgets, availability, data — this work is ongoing. It is something that organizations within the Yukon government have taken very seriously. Your individual organizations are working toward developing this as a platform in which to inform the decision-making.

It's important for people to know that this is ongoing, and its important work and tries to get at answering some of the questions that were posed around risks for shale gas development.

I want to speak a little bit about the risks. I think we've heard yesterday — and you've seen it in a lot of the literature — about the risks and you can make long lists of it. In the CO_2 storage world, which has very much the same framework, if you like, in terms of those risk assessments — as the discussion is around shale gas — you're left with a sort of cartoon picture of where you have to try to balance the risks and the benefits.

In general, when you look at this, the benefits can be quite high, and if the perceived risk is quite low, you can have a project that's quite acceptable. You can even move the benefits quite low. You can perceive that the benefits might be relatively low to your particular area, to the Yukon, to a particular sector, and you can still have a project that's tolerable. But, as soon as the perceived risk even starts to move from very low to low, you can move very, very quickly into a position where the project is rejected. So managing and balancing the risks with an appropriate regulatory framework is going to be key and not easy to do. If large-scale CO_2 storage work that has been done over the last while has shown us that it's a challenge at scale, the shale gas will present the same challenges.

Are Yukoners alone? Absolutely not. The issues that you saw yesterday and have heard about and read about — if you look at public opinion polls and stuff, and if you look at reasons given for those not in favour of shale gas development — in Pennsylvania, in particular, there has been a lot of work.

The main author of this, Bernie Goldstein at the top — Goldstein et al — was a member of the expert panel as well. You can see the same issues: environmental concerns, negative effects on water, negative effects on air — the highest percent. These are important issues. They won't have answers today. I'll speak to some of the issues around how it's managed in the CO_2 storage world to help inform how shale gas should move ahead — definitely not alone in identifying those issues.

One of the things about risk is that risk is an interesting topic. Risk itself can be managed; it can be minimized. You can share the risk, you can transfer the risk and you can accept a particular level of risk in a project. One of the things you cannot do is ignore the risk. I think that what will happen over time is that this conversation — the conversation with the public, the local stakeholders — they need to be involved in that process. It's actually a very, very important process. One of the things about hydraulic fracturing, however, is risk perception. This will not go away.

As an example of this, I could ask the question, what is BP? If you looked at what BP is to a layperson, they would think Boston Pizza. If you asked somebody in the oil and gas industry, they would say it's BP — British Petroleum. If you asked a surgeon, they would think it's blood pressure. So this issue of risk perception around hydraulic fracturing becomes a very, very critical element to deal with and in some cases, is a non-technical issue. You've heard a lot of discussion over the last few days — a lot of stuff in the literature about the technical issues. This is as important an issue to deal with.

The question you could say is what is hydraulic fracturing and you know that if we looked at those sectors, we would get different images of what hydraulic fracturing is.

One of the things to note about risk in your definition in your remit is that it is measured in terms of consequences and likelihood. There is occasion — and it has come up in the conversation and many times in the literature you will see this — that people will refer to risk, when in fact what they are doing is hazard identification. Hazard identification is extremely important and in fact it is one of the most important front-end steps that you do in a risk assessment, but it is important in this discussion to remember that risk for people — with the way they deal with risk — is that it has to do with the likelihood as well as with the consequences. In a great many instances, the discussion tends to focus a lot of times around consequences and in many cases does not spend a great deal of time on likelihood, which is a much more difficult element to determine.

Are things happening in the literature and in the industry that look at shale gas? Absolutely. There are multiple — probably over the last two or three years primarily because of the importance of this topic — where issues around risk, risk identification, risk elements, expert judgment, solicitation to try to find out likelihoods and consequences are happening. These are standard things that happen. Risk matrices are developed; risk pathways — you've heard a great deal of conversation sometimes about risk pathways — site development, drilling, horizontal drilling, fracturing, well production — a whole series of activities throughout all of shale gas development. These things are ongoing. These are things that in the development of a regulatory framework in the Yukon can be used very effectively.

These are very powerful. There are methods used to do the risk, the risk analyses, expert surveys, statistical analysis, numerical simulations — I think you heard Dr. Wendling talk about the need for more numerical work. You can take this data and you can develop these sorts of linkages to actually paint a picture about what the risk assessment profile looks like for a particular project, and that becomes the basis for risk management. Why is that an issue? All companies that go off to do something will do this as a natural order of their business. Environmental EIAs, EISs are natural components in those processes, but why this is important from a regulatory point of view is that in terms of managing those risks — and I've borrowed this from the current draft documents that the Alberta Energy Regulator is talking about in terms of how they want to move forward with unconventional resource development. They are moving from not a single well, but to a development, to a play, to a large application process. Inside that particular process are risks. People are going to be asked to identify, organize their risks, present risk assessment, risk management and risk mitigation strategies as a part of their program. I would fully expect that within the Yukon this is exactly the same process that would need to occur here.

Just to go back a little bit about scale and why does stuff exist in the literature at scale — it would help inform shale gas development. If you look at things like CO_2 storage where the same kinds of issues are important — a quantity of CO_2 is injected into a particular horizon, and it needs to stay in that horizon.

You look at things like containment risk; the pathways it would move that you heard about during deliberations, the formations, the wells, et cetera, and then ultimately into the biosphere; the water, shallow water, community, community assets, air quality and such, so those need to be linked.

This has been done, I have chosen the Weyburn project as an example of large-scale, multiple wells; 3,000 wells, all vintages — all the way from 1956 all the way through to current new wells, all different kinds of constructions. Those are all placed within a structure that allows you to go through and formulize inputs to the geosphere risk and assess the biosphere risk. These are standard processes. I would suggest that these are the processes that need to be placed within the framework of a regulatory environment in the Yukon.

So for instance, from a CO_2 profile, you look at the containment risk, and you might have to turn your head along the bottom axis, but there are things like natural seismicity, wells, microannulus, casing corrosion. Those are all elements that are identified and that we have chatted about. Numerical simulations, behaviour of the materials, configurations and historical data all go into actually calculating the containment risk. This would be the kind of information that would need to be placed in front of the Yukon people for shale gas development as well — the point here being that these kinds of processes exist for projects at scale, and they are important to learn from.

Quantification of rates is done. Features flow — how do materials move from the subsurface to the surface? I think Dr. Wendling in his presentations had a numerical model and you had some wells and some fractures and assumptions about that sort of thing. So you can do that sort of assessments. It's being done, I guess is what I'm saying.

The other part I think that was extremely important and maybe this — I had wondered where I was going to insert this but — ultimately movement of fluids in the subsurface is important from a performance point of view, but ultimately the end point receptor of the risk assessment is that assets that are identified as critical by the stakeholders, which typically in these cases is the community, the people — the people in the area are the ones who need to be consulted to identify which are the assets that they feel are the most important to be protected and those are the ones that are included in this risk management framework.

So that's what this table is. These exist. They can be used. It's a little fuzzy — if anybody wants the details, we can get it. But this table is constructed after consultation with affected parties. The people in a particular area are asked, what are the community assets that you think are important? Over the conversation, easily water, air quality — but other things like reputation, quality of life, other aspects, all go into this particular assessment that have to be included in the table. These are difficult things to do at times, but extremely important and need to be included for shale gas developments.

The range of this stuff by industry — these charts change a little bit — but this just gives you an example, that industry does do this. Their tables are slightly different, but they do do this. They look at consequences to people; if you look on the left-hand side — people, loss, environment, reputation — and on the right-hand side is an assessment of probability or likelihood and, by combining those assessments, it puts them in a particular part in that chart. Given a particular acceptable threshold, if it lands in the red or in the orange, there is a requirement that that risk needs to be managed into the yellow and preferably into the green zone.

In shale gas development, public data exists — a public perception related to this. If you look at this, it's that same kind of chart kind of inverted in green, gold and red, but you'll notice a list of risks all the way from one to 21. If you pick something like number 12, "frack opens mud channel in the cement in the wells," and you can find where number 12 plots on the chart by this assessment. This is a particular assessment — generic — that has to be done for every site-specific project development. These would be the expectations that you would need to see as industry moves forward in any particular area.

The guiding principles for some of this process — I actually think that the language and the words that exist within this particular standard on the storage of CO_2 are quite instructive. I think that regulatory bodies that are contemplating shale gas at scale need to look at this particular standard in terms of the language.

If you look at some of the stuff I've just chosen — risk management and monitoring out of it — you can see the language in terms of the standard. You know, the purpose of risk management is to ensure that the opportunities and risks involved in an activity are managed and documented in an accurate, balanced, transparent and traceable way. Those words are not chosen by accident. Monitoring and verification, which Dr. Mayer talked about this morning, address health, safety and environmental risks and assess storage performance. If you look at the words that exist within that, it is very easy to take that and actually substitute, in certain cases, the words "shale gas development." It is exactly the same philosophical approach for dealing with risks and managing those risks — so something that is very important

So I think listening to Dr. Mayer's presentation this morning and I think he hopefully spoke eloquently and convincing by that the technology is there to effectively monitor some of those changes in the shallow groundwaters, which is exactly one of the risks that need to be managed for shale gas development as a part of this kind of process.

In the latter part of the presentation, I just want to focus on a couple things. One is on well construction and again to make the point that there is work being done — has been done, is being done — and is contemplated in regulatory language about the way that wells are looked at in terms of shale gas development. The second thing I want to chat about a little bit that you hear about occasionally is this thing called microseismic monitoring and speak to that around how that is used to confirm how hydraulic fracturing occurs in the subsurface and what it means in terms of pressures around the hydraulic fracturing process and immediately following the hydraulic fracturing process.

So just well construction — a few things again just to remind ourselves that the typical regulatory environments will always specify series of pipe that are meant to protect certain areas, in particular, and the one that is most important is surface casing. In all jurisdictions, it needs to be placed at a significant distance below United States — USDW — underground sources of drinking water or potable groundwater horizons.

In the Yukon, for instance, following up from Dr. Mayer's presentation, that would be a key. If this was to occur in any one of the settings of the basins and anywhere there was a development occurring you would by default need to determine the base of usable groundwater. That's a shifting definition. That's not an easy definition to come by. It's technical. Dr. Mayer can speak to it in more detail, as many others can, but in some locales like Alberta usable groundwater is 4,000 TDS salinity — total dissolved solids component — whereas there is a move and, in many locations, it's as high as 10,000. So that changes the depth and there would need to be decisions on where that elevation is and then that actually sets where surface casing is. You need to know that. That's not a negotiable item.

So the people who chatted about this — there's intermediate casings, there are reasons why you would do that, the depths of your drilling, the mud pressures and production casing and so on — and people yesterday and in the technical literature have lots of other diagrams.

One of the things that was noted, of course, is that all the casings are isolated by cementing between the casing strings. In some cases and in some jurisdictions, you will see in the literature that cementing is not done to surface. You'll see language, such as wells need to be cemented and the intermediate string cement must come up to at least 200 metres within the surface casing string. I think in most settings now, you will see that the language is changing, that those casing strings need to be cemented to surface. In all cases, the cement must come up and you must get what's called "cement returns." Those proceed in the field with operational practices that are documented in regulations documenting cement returns and other things like that. I want to speak to how things can change for shale gas development and where some of the languages are going.

This is a very typical process. You saw some of them from industry and you saw some from cartoons from some other people yesterday. One of the things that I wanted to mention around the well integrity is that there are multiple ranges of technologies that people use to assess the wells. This is not an uncommon practice. This is not something that is an oddity. These are things that are done in evaluation programs. You have things that are sometimes referred to as "isolation scanners" or "mechanical integrity logs" that are done on wells that check the quality of the steel, whether the steel is pitting. There are logs that allow you to check behind the casing. All of these logs seem to have — everybody has an acronym, but these are sometimes used as pulsed neutron — where they will scan in behind the well and they will get a response back from the formation, analyze the spectrum that comes back, and it allows them to assess whether there is oil, water, gas in behind the casing.

In particular, for well integrity, standard processes are things called "CBLs", cement bond logs. I think the easiest way to think about a cement bond log is the ringing of a bell. If you can imagine between the rock face and the cement and the casing that, if you had no cement and you put down a tool and you tapped on the liner, the casing — because there is no cement behind the casing, it would ring. So that would be like ringing the bell and you'd hear it. But if you tap the bell — but you are holding your hand on the bell and you tapped it — you would just get a thud. You would not get the ringing that you would hear from a bell. What the little grey images project on the right-hand side is this ringing. If you don't see any ringing in a CBL log, that's an indication that, in fact, the cement has filled the gap between the cement and the formation.

They can get more complicated. There are other acronyms — this thing called USIT, which is an ultra-sonic imaging tool. Same kind of process where it sends out some waves, but what it does is it looks at — instead of an average response of the well, it looks at 360 degrees around the well. If you can think about it having ringing bells around 360 degrees, and what you can get is a map that you unwrap and — 360 degrees you have a well — and then you unwrap it and you look at it in a flat sense, and so this is at one section, and you unwrap it. So this is the complete circumference of the well, and what you can do, based on the signal that comes back, you can assess whether you can have microannulus — or channels — or you have a solid interface in behind the channel and you can look at it in 360 degrees. The bottom line is that these tools exist. There are always challenges to running them — CBLs are cheaper, USIT logs are more expensive — but the technology exists to do this assessment.

So, relative to shale gas — I know that we are hearing later today from the National Energy Board, so I don't want to steal their thunder, but I did need to extract one component out of the NEB because it is actually very instructive of where the language is going from a regulatory point of view about generating assurances about well integrity during shale gas development.

This is not going to be about drilling a well, looking once, producing the gas and then putting some cement in the bore hole. It will not be about that. It will not be about that in other jurisdictions and I'm pretty positive it will not be about that in the Yukon. But it will not be about that in other jurisdictions. If you take the NEB language in terms of what they have generated for guidance documents for applications for hydraulic fracturing in the Northwest Territories, I did want to bring your attention to this one component. It really is just sort of this middle point. Well barriers ensure well integrity at all times during the well life cycle and under all load conditions, including completion and hydraulic fracturing operations.

This is not an insignificant language or sentence. This means that, in shale gas development, where hydraulic fracturing is used, there is a regulatory requirement that you need to run these assessment logs. You need to do them when the well is drilled and completed — you need to assess its initial conditions. We've heard before people mentioning about, "Well, if there's an issue I need to go back and remediate." Absolutely. Those logs are submitted, the well is assessed, its integrity is assessed for its operations.

What is happening now is that, in shale gas development, because of the pressures that are used to do the multi-stage hydraulic fracturing, which are typically done — not in all cases, but are typically done — down the full wellbore of the casing, is that those impose loads on the casing that then deform the casing out and can load the cement in a way that potentially damages that cement annulus during the hydraulic facturing operation.

What this language is saying is that — what you need to do now in the design of your well and cement design, is that you need to ensure — by monitoring — after the hydraulic fracturing operation that that annulus is as suited to isolation as it was when you first drilled the well. It is not insignificant.

I think you will find that in other jurisdictions — and I will, although I don't speak for the regulators — but you will find that the conversation in B.C. and the conversation in Alberta is that that post-hydraulic fracturing assessments of that cement integrity will become a standard operation. And that information will be made public and it's important to confirming the isolation barriers that exist in those wells aren't damaged during hydraulic fracturing.

In the horizontal section — switching over now a little bit to a conversation about the fractures themselves — following the perforation, the interval in the horizontal section, there is the fracturing. You always get cartoons like the one that you see on the bottom right. They show sort of a dendritic pattern like that and cracks in the rock and high energy in multiple stages. You can find these cartoons anywhere. The question becomes — as you look at the risk and you are trying to manage the risk and convince yourself that there are no pathways due to the hydraulic fracturing operation itself — how do you confirm it?

I want to show you some data that people have shown a bit already, but I just want to reemphasize it. The biggest issue is the reason that they are doing this, and the reason why, if you accept that I would like to exploit the hydrocarbon resource — the shale gas — is because of the permeability. The permeability is so low that the only way to generate flow in those environments is to actually generate these large dendritic patterns — fractures open up as much surface area as possible with things like proppant, which people have talked about, in order to maintain those fractures — the permeabilities are extremely low, very low.

You have pictures like this where salt — somebody had even mentioned salt caverns the other day — but salt has extremely, extremely low permeabilities. Shale gas is down in this region. That's why you hydraulically fracture. One of the things about the gas itself — and this is going to be to my final point — is that in general there are some natural fractures that might contain — if there is a natural fracture system, it might contain free gas. Most of the gas sits adsorbed on the mineral surfaces and in nanopores and in the mineral matter within the shales.

It is very important as part of the reservoir characterization stages. They do a lot of work on mineral components of these shales and stuff to try to generate estimates of the resource.

Lots of words — this is why — this is the part they're looking for. You have organic matter, you have nanopores that are in here, and it's the gas that comes out of this mineral matter that needs to move to the fractures and move through the wells. When you look at these pore spaces — these are just some pictures and many of you have probably seen these all before — they are very, very tiny pore spaces that the gas needs to flow through, in many cases, to these fractures and then move to the wellbores. You need to depressurize the formation. There is a large pressure that happens during hydraulic fracturing in order to create this dendritic pattern but, following that, you need to put the well on production — that is the term — and to drop the pressure in the wellbore in order to cause the fluids to move to the wellbore and be produced to the surface. You do not sustain high pressures in the shale gas reserves over long periods of time because you need to drop the pressure in order to produce the gas.

This may be more for people who haven't looked at this. George King is a very well recognized expert in the world. He has published extensively and in a very open and transparent manner about how things happen in the oil and gas industry. I would urge anybody, as this title says, and you notice that — I did. He's a university researcher so I figured I'd better read that as well. This is a very good paper. Very good — right from the start to beginning it talks very openly and honestly about the issues that are involved in hydraulic fracturing, and if anybody hasn't read that, it's very important.

Fracture growth is complex. It can happen. It can go in different ways: it can go horizontal, it can go upward, it can twist, it can move sideways, there can be multiple interacting fractures, you can have fluids moving maybe to a different — this is just cartoon from a vertical. It change directions based on stress. There are a lot of technical issues. We're trying to generate this in the subsurface — these cracks like this that always look like these cartoons. There are a number of monitoring methods, but in particular, the one that you will see in the shale gas world — it's spoken a lot about — is this microseismic monitoring.

I just want a few slides to explain that concept and why that's used and perhaps offer that this in fact should be used more in terms of shale gas due to wanting to confirm in all cases that the fractures stay where people have said they're going to stay.

So microseismic is a pretty well-accepted technology based on geophones. Geophones have these little elements in them called "accelerometers" that measure small amounts of shaking — I guess if you want to call it that. You'll see words in the literature — this thing called "three components", which just means that in any particular geophone I can measure movement in the vertical direction and in two orthogonal horizontal directions. That means now, when I have a bunch of geophones in this observation well, by measuring how the strain waves away at these geophones, I can say that the little microseismic event happened here and not there, and so people put them in. In most cases during the hydraulic fracturing operation, people do this. In general, it's not a regulated requirement.

But you've seen this plot. People have used this plot before. I think this is about as powerful a data that exists in the public domain currently to speak to the issue about the height of hydraulic fracture rise within a horizon. So if you take this and you look at things like the Barnett Shale that people hear a lot about, and if you look at this curve — I've taken the liberty of switching this to metres. This was chatted about just once yesterday. This curve is organized on fracturing stages sorted by this perforation mid-point so this is the depth of where the perforations happened over a range of projects. There's kind of a list here, and it shows you all the way up until about 1,400 metres all the way down to about 2,600 metres. These heights are all detected by microseismic monitoring. What you find is that, in all of these cases, there's a deepest aquifer depth in this horizon, a particular limit on the shallowest horizon, and a depth interval. So, in this particular case in the Barnett Shale, one might get to the point of saying, "Well, in this particular case, with the factor of safety, we will not permit shale gas fracturing to occur within 1,000 metres — this factor of safety — of our deepest aquifer."

If you look at the Marcellus, which is a lot of activity — same plot, less amount of data, but still microseismic monitoring over a range of these stages all the way from 2,600 up again to about this 1,400-metre depth, and again, a range of data that says, here's the deepest aquifer, shallowest fracturing effects, and 1,100 metres.

This I think speaks to the issue about regulating especially at the outset. If you want to call them offset distances, but they are distances to which you would initially allow hydraulic fracturing that based on current data suggests that the risks to movement of the hydraulic fracturing to the shale horizon is minimal. In microseismic, these are the clouds you get. You have two horizontal wells, you have fracturing occurs, you've got a monitoring well, you measure these — they are just coloured by the events or the stages — and you get these clouds.

So why are these clouds important? Well, people will look at this and say well okay, in these clouds I have this fracture network that I'm going to use. I'm going to overlay them on my microseismic event and I'm going to use this to simulate or predict how I'm going to produce gas from this reservoir. What about from the risk point of view? Well, one of the things that you do with this — and this is data that would be supplied to the regulator and to the community and I'll explain that in a second — is that this data shows that in this particular location, the clouds of events in the hydraulic fracturing are all contained. Here's a planned view of another one where in fact the clouds of the microseismic events are all contained. Conversely, this also shows if it's not contained. Microseismic events will show movement along fault plains if fracturing is moving in an unintended direction. It becomes very valuable performance data to confirm what has happened during a hydraulic fracturing operation.

One of the things — and to my final point — this is issue about the decline curves. Everybody has seen these things — there were some plots yesterday about high rate declines that go out and some perhaps debates about the time that these wells will exist.

I think in most cases people are expecting that these declining curves will go out in decades, not just a couple of years — large numbers of wells. But from the point of view of the wells in the movement, this is a just a reservoir simulation that I could find to demonstrate this thing. This particular plot is again, this map, these fractures and I am now trying to produce gas out of this well, out of these sets of fractures.

What this shows is that now when I put the well on production, this red area is the original pressure in the shale horizon and what this shows, in this particular case, if the original fluid pressure is 22 MPa, I draw the pressures down in this wellbore, where in the reservoir in fact they get down to 8, 9, 10 or12 MPa. So all of the gradients now are actually moving into the well. There is no driving force to move fluids from the hydraulic fracturing horizon up and through the geosphere. This is a very important mechanism that you need to take into account when you take a look at some of these long-term issues.

One of the things I did want to make a final point was about community involvement and again CO_2 storage. I think in the Yukon there is a very important lesson to be taken from some activities that have been happening in the CO_2 storage world. One of the biggest projects in Alberta that is happening right now is being conducted by Shell — it's called Quest Carbon and Capture Project. It's very large. Shell, as a part of this process, has actually established something called a community advisory panel in the community of Thorhild, which surrounds where the injection wells are.

Over time, what has happened is that this community advisory panel — which is made up of a principal of a high school, the fire chief, local landowners and a couple high school students — is that the monitoring technologies that are being deployed for this CO_2 injection project are being explained, talked about and bringing this community advisory panel up to a level of understanding so that when monitoring data is received from the program, the community advisory panel is actually among the first people to see this data, talk through all of the data — what it means — so that if anybody in the community asks a question about it, it is people in the community who can answer those questions. It's a very important model to take forward for shale gas development as well. It means that community is one of the very first people to see this monitoring data as the project develops.

So that will conclude the presentation and I look forward to answering any questions.

Chair: Thank you very much Dr. Chalaturnyk. The Committee will recess for ten minutes before we start with the questioning.

Recess

Chair: The Committee is resuming its discussions on this very important matter. We're going to proceed with questions, as we discussed earlier. I would ask the Committee to be recognized by the Chair so we can make sure that your microphones are on.

The first questioner will be Mr. Elias.

Mr. Elias: Thank you, Madam Chair, and thank you, Dr. Chalaturnyk, for accepting our invitation to come to the Yukon and share your expertise with us. It's a very good presentation today. Thank you.

Shale gas and oil extraction, especially in western Canada, has grown exponentially and so has the technology associated with it. On the Council of Canadian Academies website, there's a section there that's investigating the state of research and development in Canada. Under that, oil and gas extraction is one of the items.

Because we're trying to determine our own destiny here in the Yukon and this technology is changing so rapidly, can you expand on your knowledge of the research, whether it's with the Canadian Association of Petroleum Producers or industry or universities that are dealing with wellbore integrity, looking at annulus protection, or whether it's additives — the chemical compounds and the way that they are using them — whether they're moving toward environmentally friendly compounds instead of carcinogenic compounds, for instance, proppants, the amount of water that's being used, for instance — because if there's any research and development out there that is an advancement or is underway, our Committee or I would like to know about it. If you can expand on that, that would be great.

Mr. Chalaturnyk: It's a great question. In fact, there's actually a great deal of work being done. I chose to speak to CO_2 storage today a bit, because that is a world over the 10 years in which a great deal of effort has been placed on well integrity.

Much like the conversation that you've heard and will continue to hear, is that a fluid leakage pathway along the wells tends to be the one most highly ranked risk for shale gas development from the subsurface. It turns out that's one of the largest risks on the $C0_2$ storage side of the world as well.

A great deal of work on cement, cement properties — large programs by something called the carbon capture project, where samples of cement that have aged for 40 years down a hole have been cut out of the annulus region and analyzed the cement quality. For instance, Dr. Wendling, in his presentation, mentioned some work he had pulled from that workshop in the United States by a fellow by the name of Bill Carey. I know Bill Carey extremely well at Los Alamos National Lab. Bill Carey cut his teeth testing cements for CO_2 storage. That is where that work was actually initiated. A great deal of work in NETL — National Energy Technology Labs — on cements, exposure to chemicals, additives, people worrying about how to mitigate now, how do you repair leakages, different techniques.

There is a huge body of literature — tough to chat about it and answer it effectively here — but a great deal of work has been done to look at issues around the long-term behaviour around those wells. There is a lot and there will continue to be, I'm sure. I definitely can find some of that for you, if you would like.

Chair: Mr. Elias, 30 seconds.

Mr. Elias: Thank you, Madam Chair. Very quickly, you mentioned about — it's wellbore integrity again — these ultrasonic imaging tools that create that 360-degree map of the wellbore — and sonic scanners. Is there a homogeneous regulation in Canada whether or not industry should use these imagining tools, these microseismic monitoring tools?

Mr. Chalaturnyk: Well, the USIT — those imaging logs — are meant to look at the annular region of the thing to see how well the cementing job was completed. In general, no, they're not specifically mandated. That's actually why I brought up the one language about the NEB — the thing is that's that issue around having a prescriptive or a performance regulatory framework. What you saw on the NEB side is a performance-based regulatory language. It says this is what we need you to do — you can use some kind of techniques in order to actually satisfy that, but we don't say you shall use that USIT tool, because there are lots of other reasons operationally and things like that. So, no, not really — it really becomes more of a performance-related language that you saw there in the NEB paragraph.

Ms. Moorcroft: You mentioned that frack growth is complex and virtually all of the presentations that we've heard served to illustrate that this is incredibly complex on a number of levels. We hear about surface and groundwater, aquifers at different depths and of different types, frack water, produced water and flowback. One of the areas that there has been a lot of discussion about is the percentage of frack water that comes back up to the surface. The estimates vary by studies — anywhere from 20 to 50 percent stays behind to maybe 80 percent.

What happens to that frack water that stays under the ground? Does it stay under pressure? Can it migrate through natural factures in the strata or the rock underground? I'll maybe pause there and then hopefully we'll have some time for some follow-up questions.

Mr. Chalaturnyk: Right now I would suggest that, in the operational scientific world around the flowback fluids, that is an area of a lot of work at the moment to solve that mystery of the fluids. After fracturing, I think one of the current thoughts is that that fluid is somehow absorbed on the clay fractions or held by the clay fractions within the shale formations themselves.

But one of the reasons I showed that last little bit on the slide is that, after hydraulic fracturing and you go into production mode, all of the pressures in the region of the fractures are toward the wellbore. There is — hydrogeology, the stuff — I mean, Dr. Wendling gave a great presentation on that in terms of gradients and all the rest of it — but that really is the issue that, under production, the flow gradients of fluids within the formation are actually going to come back toward the wellbore in terms of the gradient. So whatever is holding the fluids, either by — a term that's used occasionally is something called reservoir compartmentalization. So if you create a bunch of fractures and you put fluids out there and you put the well on production, some of the fractures next to the well might actually close. So what that does is it limits the ability for fluids to move back toward the wellbore.

It's a pretty complex question, but overall the gradients moving the fluids toward the wellbore will prevent their movement at a large scale up into the geosphere, but it's an unsolved question at the moment about where that fluid sits.

Ms. Moorcroft: Related to that is what the fluid does and what it is. Is there any way of testing the chemical nature of the fluids that are left underground and is there any way of detecting whether those fluids can move through natural fractures in the rock or migrate into other strata?

Mr. Chalaturnyk: Currently right now, for the people who are really trying to focus on this issue about where does this other 40, 50, 60, 70 percent of the water go, I should point out that those — it's very easy to say those statistics, but the numbers don't stay still. When you initially inject the fluids, your initial chemistry of the fluid that comes back is primarily fracture fluids and, over time, it will become more saline as more of the sort of reservoir brine high-salinity fluids come back into the fluid. It varies over time and so it's that chemistry that people are looking at to try to understand and explain where or how is the fluid contacting the formation and why does the chemistry change in that manner. I think that was it, in terms of the chemistry changes. I think that was the question.

Mr. Silver: I think it's worthy to note to the gallery and to people listening at home, as well, that this is the second time that the select committee has spoken with Dr. Chalaturnyk.

In your first in-camera presentation you mentioned how we need to look past the frack site as well and you mentioned how important it is to ask the question, What are we doing with our resource? Can you speak to methane emissions related to off-site statistics, for example in pipelines? Is there enough data there to make an argument that extraction for purposes of export would actually reduce our carbon footprint?

Mr. Chalaturnyk: Great question. I would suggest that that probably is one of the most hotly debated topics around shale gas development at the moment, because in most cases shale gas development is positioned as a viable replacement to coal and to oil as a fuel for power generation, electrical generation, and so, in many cases in most locations, is touted be a vehicle for cleaner emissions, lower greenhouse gas emissions.

But there is that one issue out there that was chatted about yesterday and it is chatted about in the literature — this issue around the emissions associated with large-scale development, fugitive emissions and the studies that are ongoing. I'm not really sure there is an answer at the moment. I think, like many of the other speakers have noted, that some of these studies that have been done in Texas at a much more rigorous, larger scale need to try to look at those issues.

One of the issues around fugitive emissions, especially on the surface, is that if those issues are identified, like in many things in the oil and gas processing industry, those are risks that likely can be managed. Those are places in which changes can be made in the way those facilities are constructed and managed in order to try to reduce those emissions. But in terms of the amounts in that argument around greenhouse gas emissions and climate change, I think it will take a bit longer to collect data to get a definitive answer.

Mr. Silver: I guess it all comes down to where we regulate the industry to look, really.

Given our remote location, what would be the best method of dealing with used fracking fluids, both from an economic and from an environmental point of view?

Mr. Chalaturnyk: Well, in the initial learning stages in the Yukon, I think the most viable solution is deep injection. I think that there are jurisdictions in North America, and even close to the Yukon that the Yukon can draw on — B.C., but Alberta in particular — for regulations around how to do that and how to monitor it appropriately. I think deep well injection becomes the most viable technique for actually making sure that those fluids don't enter the ecosystem on the ground surface.

Chair: Mr. Silver, 30 seconds.

Mr. Silver: My final question is about the CCA publication on hydraulic fracturing. It is delayed and could you comment on the reasons, in your opinion, for these delays?

Mr. Chalaturnyk: I think one of the reasons is that it was such a fast-changing, complex area, much like the discussion that the select committee has been going through. I think the expert panel had exactly the same discussions, the same conversations about the challenges. The remit from there was to actually assess the current state of knowledge. So there was a particular way in which the expert panel proceeded through its deliberations in terms of trying to find peer-reviewed, publicly accessible data that would speak to the issues that the select committee has heard about, and that became challenging.

It changed with time. There was report after report coming out. It changed the data that was available to try to form conclusions on, and that continued to change the discussion and the available information in which to base the report on. I think what you see now is that eventually the panel itself just got to the point where it had to draw a line to say that this is the available information to this date and it needed to prepare the report with these recommendations.

Hon. Mr. Dixon: In the last presentation, Dr. Mayer indicated that the most likely pathway for contamination to occur — whether it be fracking fluid, formation water or natural gas occurring from the depth coming to surface or coming to groundwater — was along the wellbore. You have indicated that there are a number of tools — the CBL, the USIT — that can tell you the quality of your wellbore and where exactly there might be a problem. Once you identify that, what do you do? What happens if you've got a compromise at fairly great depth? How do you repair that, and can it be repaired?

Mr. Chalaturnyk: Sure, there's a wide range of remediation technologies that happen. I mean the fancy word or the typical word that you hear is a "cement squeeze". That's not always the thing, but that's the easiest one to picture in your mind. You find the intervals, you re-perforate the casing in those intervals, and you inject — it can be chemical-based cements, ultra-fine cements, and there is sort of a range of options that service companies provide for that, depending on the characteristics of it — and squeeze cements in behind those intervals in order to actually isolate the horizons that have shown up to be poorly cemented.

Hon. Mr. Dixon: You showed the slide we've seen a number of times before that shows the lower limits of water — fresh water, at least — and the upper limits of the fracture height and the distance between them. You indicated that you could set a maximum distance that would have to be maintained between the lower limit and the upper limit of the frack.

Isn't the distance less relevant than the actual geology? If you had a great distance and it was fairly permeable and had existing fractures, wouldn't it be irrelevant how far it was from the fresh water — the lower limit of the fresh water to the upper limit of the fracture? Can you comment on that? I'm having trouble understanding why the distance would matter more that than the geology itself?

Mr. Chalaturnyk: In that scenario, think distance first, and site characterization comes after. Site characterization is going to control it, but what I'm saying is that once you've started a high-energy hydraulic fracturing operation — you can find stories where high energy fracture operations — and I think you heard some yesterday from the B.C. Oil and Gas Commission on the inter-well communication. There's a large amount of energy placed in the formation that drives the fractures a certain amount.

The issue there is over a wide range of conditions that are pictured in those plots. There is a limit, given all of those case histories, that, in the early stages, you do not want to go above. So, pick the 1,000 metres — whatever it might be for the Yukon — but let's pick the 1,000 metres. Below the 1,000 metres now, when you are going to apply for a shale gas development, the site characterization issues now become important. They become critical. You have to do the site characterizations. You need to know if there are faults. You need to know if there are legacy wells.

There are all other things that go into describing that environment as being safe for that shale gas development.

But given all the historical data, it seems to me prudent to say that my first level of risk management on that is to say listen, nothing above 1,000. Historical precedent says that we have this wide range of experience. I don't mean to say that "1,000, you're done, thanks, we're finished." No — I'm saying that becomes your first set and then below that come all the other issues around site characterization, well construction and all the other issues, absolutely. Good question.

Mr. Tredger: You mentioned — we were talking about — wellbore integrity and I am wondering about degradation over time. Once a well has been put to bed, or abandoned, how is it determined up and down the wellbore whether or not there is degradation? Do we have a means to determine that?

Mr. Chalaturnyk: Great question. I thought that might be asked. There were some comments yesterday in the questions about well abandonment that made it sound that it just kind of happens naturally. I don't think that's going to happen, and I'll take that from — there are regulations that exist in other jurisdictions around how wells are abandoned — how to isolate, how to place cement and other things — but when it comes to things like the questions that the select committee is worried about and the people of the Yukon are worried about, there are other approaches to abandonment that actually help to solve some of those issues.

I will give you a 'for instance' — one of the options for well abandonment for CO_2 storage that would be equally applicable if it was important in the shale gas world is all of the casing and all of the older cements in a well. So let's say the well is 25 years old; the project is being abandoned and you are going to go for your recertification certificate. You basically under-ream all of the casing and all of the cement for an interval above the immediate cap rock above the shale gas horizon.

That horizon now is actually fully placed with brand new cements. There is no interface. There is no interface between the steel and the old cements. There are no interfaces to degrade and there is ample evidence from down-hole experience about just even Portland class G oil well cements surviving for very, very, very long periods of time. The idea around abandonment is not to abandon the well to be able to go back and do monitoring over a long period of time. The idea is to abandon the well in such a way that you've created an environment that doesn't produce those interfaces over time and effectively seals the well.

Mr. Tredger: Over time, though, the ground shifts. We talk about tectonic plates moving. There are faults opening and closing all the time. One of the concerns expressed yesterday was not necessarily something that leaks to the surface, but goes from one zone to another. Is there any way to monitor that once a well has been abandoned 10 years, 100 years, 500 years down the history? The concern is that we have these produced waters at one level; they may move to another level; levels of water may move up from one zone and down to another in that interchange. As this is a conduit, is there any way we can test over time to see if indeed there is a mistake or something has been put in that hasn't completely sealed it?

Mr. Chalaturnyk: That would be an extremely difficult thing to do. I'm not sure, from all of our experiences in thinking about the long term — remember in the CO_2 storage world, this is exactly the same question and there, the time frame is 1,000 years. The question in that environment says, "If I have a project and I'm going to put all of the CO_2 into the ground, I need to abandon the wells to assure their integrity for 1,000 years." Nobody in that setting says, "I'm going to abandon those series of wells and put in place monitoring that allows me to monitor those wells for 1,000 years." That is an extremely difficult thing to do.

You can in a short term, but what you want to do is, at the end of the project, you want to do the kind of assessment on the well — the kind of tools I was talking about, other things; it's historical performance, including modelling and prediction. That verification work goes some measure of actually confirming that the well is going to behave how you think it is going to behave over the long term with its abandonment strategy.

I cannot think of a particular — at the moment — a technology that you would put in a well that would last over those periods of time and would allow you to monitor something. If you put something in the well, you are creating a pathway anyway. I don't think that's how people are thinking about abandonment. The idea is to put in place something that is robust enough to survive over those long periods of time.

Chair: Thank you. We're going to move on to our questions from the public gallery. We're going to start with Mr. Elias.

Mr. Elias: Thank you, Madam Chair. This question is from Sandy Johnston. Risks are informed by knowledge of the likelihood that bad things happen. If industry has not been transparent on reporting incidents, how does that affect risk analysis and how do we deal with this?

Mr. Chalaturnyk: A great question. The way you deal with it is that, when in the regulatory environment, you ask for the submission of a risk assessment and a risk management strategy. It's non-negotiable. In this particular environment, given the assets, the community assets that people feel are important — if I can use the term "the issuing of the social licence" in order to proceed with a development — demand that kind of transparency and it's a non-negotiable issue. They need to honestly participate in the risk assessment process, period.

Chair: I have a question from Sally Wright.

How can industry afford to reduce the risk to the environment to nil and still make money when gas prices are so low?

Mr. Chalaturnyk: Risks will never be reduced to nil. That is absolutely impossible to do in any setting, let alone shale gas. You ride your bike to work in the morning and the risks are not nil. In fact, I would submit that if you come across somebody who actually tells you that we're proceeding with something and the risk is zero you should be very careful.

This is not about getting risks to zero. This is about — for the Yukon and shale gas in particular — putting in place a regulatory framework and a policy framework that allows you to manage the risks to a level that is acceptable that allows the process to occur and the shale gas to develop. Where that acceptability or that tolerance limit sits becomes a discussion for the people of Yukon, but the risks are never zero.

Ms. Moorcroft: A question from Davina Harker regarding well integrity tests. What if you ring the bell and/or use ultra-sonic and find gaps? Does industry abandon the well? How do you remediate if you find a pocket failure at one kilometre underground?

Mr. Chalaturnyk: The issue will be from an industry standpoint where the ringing occurs for sure. In general, if there is a horizon in the annulus region where the ringing detects incomplete cementing, there would be very few cases — I'm even struggling to think about where they would be — where that would not be asked to be remediated. The isolation that occurs between the steel and the formations is meant to prevent inter-zonal movement of fluids, not even necessarily fluids moving to the subsurface.

In the subsurface, it's meant to prevent inter-zonal, inter-formational movement of the fluids. If there are those kinds of regions, in most jurisdictions or settings those will ask to be remediated. How the remediation occurs is what we had chatted about before. I mean, conventionally, the term is the "cement squeeze"; it's the simplest one to think about. There are other, fancier techniques that could be applied for more difficult problems, but in general it's this sort of cement squeeze operation. The casing is perforated and cement is injected in behind to try to fill all of those gaps and then the assessment tools are re-run again to confirm that those gaps are filled. In many cases, an additional internal pressure test is done to ensure to that that interval actually holds pressure. So there are a series of tests that are done to ensure that even a cement squeeze has been done appropriately.

Mr. Silver: We have an anonymous question from the gallery. Do you think the wellbore casing will last for seven generations?

Mr. Chalaturnyk: Seven generations is 140? No — nice chuckle from the gallery. Let me explain a little bit. Not seven generations, no. Is there proof in the operating world in the well cementing world of a casing lasting 50 years? Absolutely.

The key — and I think this is pretty much accepted now; I don't think it's debated much — is if you generate with normal carbon steel a very good cement job that stays in contact with cement and is isolated against the formation, Portland cement, the oilfield cements — if it isolates against the casing in that fashion, that is sufficient to actually arrest corrosion of the casing, corrosion of the cements and can last for a long period of time, but not seven generations.

Hon. Mr. Dixon: This question is from Davina Harker of Whitehorse.

How do companies ensure safety for well placement of a well when the subsurface has not been pre-mapped?

Mr. Chalaturnyk: That actually becomes a pretty key component in terms of the drilling operations. The drilling companies are quite expert at that. Wellheads contain devices that allow you to control mud pressure, control kicks, blow preventers and other things that exist on the wellheads in order to control those pressures while they circulate the drilling muds.

There are in certain applications techniques that allow you to use measurement while drilling — techniques to measure pressures down a hole during the drilling operations. So there are multiple technologies that are used in the drilling operations that allow you to manage the pressures.

Mr. Tredger: From Werner Rhein: Professor Chalaturnyk, you are involved with the risk management of greenhouse gases by underground storage of carbon dioxide. Why should we increase this by developing even more CO_2 and methane with fracking? Should we not invest more into alternative energy and mitigate greenhouse gases by doing so?

Mr. Chalaturnyk: Foregoing the arguments about fugitive emissions, my expertise is in geomechanics and well integrity and other things, but we sort of dealt with this world of CO_2 storage for a while. But I'm a believer in the argument of natural gas as a cleaner burning fuel for a displacement of coal-fired power generation. There are other things that happen in that particular area that, I don't know — to me there's a value just as an individual.

Now hydraulic fracturing — again, this is this issue about shale gas development. The methane that exists in shale as a reservoir can only be accessed by hydraulic fracturing. So there are those issues that everybody has talked about and the select committee is dealing with in terms of the risks, but the production of methane from shale gas, like Dr. Mayer had mentioned, if it's done in that responsible, sustainable manner, I think is a path to lower emissions. It's complicated though — complicated in terms of the global politics and energy consumption and energy production.

Mr. Elias: This question is from Don Roberts. Has your university department, you, your research or your work as a consultant been funded in whole or in part by the oil and gas industry?

Mr. Chalaturnyk: Yes. I think that, like all of these things, there are certain elements of the process or of the technology that certain companies want answers to. They are not scared of the answers and they need the answers, and so in many cases they do turn to universities and other people for research. In my particular case, for instance, as disclosure at the university, we are about to embark or have embarked on an extremely large project for what's called "reservoir geomechanics on conventional recovery", including shale gas, that is supported by 10 industrial companies and the names you do normally notice. But it's also supported by a large federal government funding that recognizes the industrial support, and the industrial support comes unencumbered. It is annual support for graduate students and the research program without a specific direction on "thou shalt do this and thou shalt do that". Those are important elements in pursuing some of these technical questions.

Chair: I have a question from Jacqueline Vigneux. How expensive is it to repair casings and wellbores? How many wellbores are there in the U.S. and Canada leaking already?

Mr. Chalaturnyk: I was surprised yesterday — and I apologize that I don't have the reference. There was a study done in Alberta — and the select committee has seen it — by Bachu and Watson that took a look at historical ERCB records having a lot to do with this shallow vent flow stuff. That particular study found that — I don't remember the numbers, so I won't peg it — an appreciable number of wells had surface casing vent leaks. They are the shallow flow issues that Dr. Mayer had spoken about that I think, in most cases, have been allocated to shallow movement in the subsurface. I think you would find that for those shallow casing vent flows, there are a number of wells that do have that issue in terms of completion in that shallow horizon near the wellhead.

In terms of being expensive to fix, it depends on the depth and the amount of annulus region that's empty and how much intervention in the wellbore has to happen. You have to bring rigs back and everything else — surface rigs and otherwise — to do the jobs. So, it varies. In some cases it can be an appreciable cost to go back and remediate the well.

Ms. Moorcroft: I have another question from anonymous. What is industry's experience in drilling in permafrost zones? What data exists for "best practices" of cementing, casing, et cetera?

Do all liquids going in and coming out need to be cooled? Is there historic data that could assure us that well integrity and ground integrity exist in permafrost zones that have been hydraulically fractured?

Mr. Chalaturnyk: That was a series of questions asked yesterday. I think those are actually perfect questions. The State of Alaska — BP, Exxon Mobil and other people in Alaska have been drilling wells through permafrost for a very, very long time They have cement formulations meant for permafrost. They have regions in the upper portion of the wellbore that are oversized, insulated in other aspects. In most cases, completion geometries change, fluids are brought up, dedicated tubing strings that have fluids in an annulus that prevent appreciable heat transfer out into the surrounding regions. So API — there are a number of specifications for drilling in permafrost that exist in terms of operational practices, both within the oil companies and within the service companies that provide drilling and completion services.

Ms. Moorcroft: Could you explain the acronym API?

Mr. Chalaturnyk: There is a very large organization in the United States called the American Petroleum Institute. I should be careful with acronyms. The American Petroleum Institute generates a whole range of standards all the way from materials to procedures and processes, and those sorts of best practices generally are documented in numerous API specifications.

Mr. Silver: Thank you, Madam Chair. Another anonymous question: In your opinion, can fracking be done safely? Many Yukoners have studied numerous peer-reviewed studies and have researched and gathered reports of horrific consequences of hydraulic fracturing. Independent a real study in Horn River Basin — 50 percent of the moose in the area are gone; fish have sores. Massive reports are coming in all over the world of serious chronic health issues. Caribou numbers are in massive decline in areas where industry continues to harm no contamination ever occurs. In B.C. and in Alberta, people have to test their game they hunt or risk eating contaminated meat. It is so serious. People no longer can eat the food of their lands.

Mr. Chalaturnyk: It's hard to argue with that, quite frankly. You are going to find in those jurisdictions where that kind of development happened at a rate and perhaps a scale in which certain checks and balances weren't in place and those are the actual consequences that will occur. So I guess in some ways the answer to the question again for me is that, if the people of Yukon say to themselves that not necessarily the hydraulic fracturing, but the shale gas itself — the resource — is important for what it represents in terms of energy and all the other sort of socio-economic benefits, then the answer to the question would be that I do think, much along the lines of what Dr. Mayer spoke about, and in other things, that there is a way to put in place a monitored decision framework that allows the process to actually proceed in a way that data is gathered to convince the public that it's proceeding in a sustainable fashion.

I think the time has come to change how you proceed with shale gas development and I think you can proceed in a way that keeps everybody informed and when you see issues you can act on those decisions. You can make decisions to act on those issues and it doesn't allow what has happened in those other jurisdictions, as they had mentioned in the question.

Hon. Mr. Dixon: This is from Sally Wright from Kluane Lake. Would you not agree that future generations bear all the risk?

Hon. Mr. Chalaturnyk: Yes. Yeah, I do, actually. It's the same argument for CO_2 storage. That's why it's so critical to have the debate that you guys are having right now actually. CO_2 storage is exactly the same problem. This is not — CO_2 storage, and large volumes of CO_2 storage, or even the issues around shale gas development that you've heard people talking about — that some of these cumulative impacts are long term or long-range kind of things — it's not my generation. My kids, my kids' kids, are going to deal with the decisions if it's not done properly.

So yeah, absolutely I agree with the question. It's the future generations that are going to have to deal with this if we don't make the right decision.

Chair: Mr. Tredger, last question please.

Mr. Tredger: Again from Sally Wright, Kluane Lake. The chart on water — I believe that was one that you had — said it was a draft but the last baseline data was 2009. Why would it still be a draft?

Mr. Chalaturnyk: Oh, sorry, that was just the data that was available. It was merely meant more to show that, within the Yukon, the kinds of questions that have been posed, there are groups and organizations thinking about and working toward that, so the 2009 really had to do with the available data set that was used to craft that first initial thing.

Unlike what you saw from the B.C. Oil and Gas Commission, which was NEWT thing, there is a process in which the data is peer reviewed, the process is peer reviewed and all the rest of it, and that's the part that needs to be all done as a part of this ongoing effort.

Chair: Thank you, Dr. Chalaturnyk. The time for questions is over. I want to thank all the visitors in the gallery who submitted their questions. The Committee will attempt to get the balance of the questions answered and posted to the website.

We are going to break at lunch now and the next presentation will begin at 1:15.

Recess

Chair: Welcome 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, allow me to introduce the members of the Committee. I'm 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 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, Minister of Economic Development and the minister responsible for 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 have been hearing and continue to hear several presentations 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, Chief Sharleen Gale and Lana Lowe, the director of Lands and Resources from the Fort Nelson First Nation. They will be sharing their experiences with hydraulic fracturing in the Fort Nelson area.

Following the 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. The page will collect the written question forms shortly before the end of the 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. Although time will not guarantee all public questions will be asked and answered, we will do our very best with the time that we have. 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 proceedings are being recorded and transcribed. If your question is selected, the information you fill out on the form may be read onto the public record. I would like to remind all Committee members and the presenters to wait until they are recognized by the Chair before speaking in order that the microphones are live.

We're now going to proceed with the presentation, Chief Gale.

Ms. Gale: Good afternoon everybody. I'd just like to thank everyone for having us here today and to recognize that we are on First Nation territories. We are happy to be in the Yukon and to present on what's happening in our territory. Thank you.

Fort Nelson First Nation has been involved with oil and gas since the 1960s, so we have a lot of experience when it comes to trying to manage the land and take care of the land. With that there are always lots of challenges. We are happy to be here to share our story with you.

The Fort Nelson First Nation is a treaty nation. We signed our treaty in 1910. Today we're going to just talk about our experience with hydraulic fracking and the adverse effects on the land, the animals and the air, water and our treaty rights. We're also going to talk about B.C.'s LNG export, the licences and the facilities, and how that will affect what's happening in our territory with shale gas extraction. We're going to talk about the inadequate consultation and accommodation and the challenges we're facing with our own government. We're also going to talk about the Fort Nelson First Nation and how we figure we can find solutions to work through this. With that, we'll get started.

Our traditional name is Tthekenneh Kue, which is "People of the Rocky River House", so we are river people. All our villages are connected through rivers. It's our means of travel. We still have community members who live off the land today — born and raised — and have not left the villages.

So the rivers are our means of life. It's where we hunt, fish, trap and travel. The river is not just the water. It's the vegetation, the fish, the medicines, the moose that come down to drink, the beaver that swim by, the muskrat. It has more value than all parts of the land and it needs to be protected. One of the things that our elders tell us is that if we take care of the land, the land will take care of us. That's one thing I always bring with me.

I mentioned that the Fort Nelson First Nation signed our treaty in 1910. The treaty that we signed in 1910 is a peace and sharing treaty, and there are a lot of things that have happened in the last 100 years that the Crown, Canada and B.C. haven't always honoured, but we listen to the stories of our elders and what was promised to us, so we really focus on the spirit and intent of the treaty and make the government accountable for how we're going to develop this landscape with the shale gas extraction.

In 1910, our grandfather signed the treaty. It was a peace and sharing treaty that confirmed our rights and responsibilities to our land and our traditional territory. Today we challenge B.C. and Canada to honour the treaty and all the decisions that are made out on the land. We've been working really hard in getting our message out nationally, to every province.

This is the treaty and it also goes into the Alberta nations — so we do have brothers and sisters over there too — and also up to the Yukon border, so I'm sure that you guys are familiar with the treaty.

I would also just like to talk about how we plan on protecting the land. When we first started in about 2006, when shale gas came to our territory, we had about two people in our lands building, and now we have built up capacity and we have about 10 people.

We work with a lot of different professionals. We work with a lot of scientists — a hydrologist, an archeologist. We have a lot of people who are really helping us try to find a way and try to strike a balance with this development. It is being forced upon us, and we're told that British Columbians want this. With our people, the biggest thing is land protection. We are not going to allow the government to just come in and rape the land. We have to find a way to protect our way of life. We will make them accountable to live up to the treaty.

We do a lot of community engagement. We meet with our community and we take direction from our community, and we have been meeting once a month. We have a community meeting and we have a lands meeting, and we are going to be ramping that up here in the next couple of months to get some more direction from our people on how we want to move forward on this development. Because we are not at "yes" — we are trying to strike the balance, and we understand that there is a lot of work that needs to be done before any of this can move forward, especially with baseline studies and so forth.

Once we get through a couple of slides here, Lana will get right into what we are doing and how we can see this shale gas extraction unfolding in our territory.

So we have lived on the land since time immemorial. We, like I said, travel on the river. We eat moose; we eat beaver; we pick berries and we fish, and we continue to do that to this day. We have the right and obligation to manage our lands and to ensure that they sustain our future generations. We aspire to have our community take a central role in responsible land and resource management in our territory. We need to strike the balance between our cultural values and the economic use of our land and resources. The biggest thing that our elders are very concerned about is water and the use of water that is used with hydraulic fracking. So we'll get into that a little bit more as we move along here.

As I mentioned, Fort Nelson has been involved with oil and gas since the 1960s. Right now, in the last five years, they have gained a lot of access into the Horn River Basin. They have built a lot of infrastructure. Right now some of the plants are in mothball condition because they don't have any markets to deliver their gas to, so everybody is aware of the LNG. It's a big thing for Canadians and Stephen Harper has lifted off a lot of environmental protections on our lakes, rivers and streams, for which he still has an obligation to us when it comes to the treaty and the promise that was made to our grandfathers in 1910.

With that, we have seen rivers and streams and little lakes being drained. It takes billions of litres of water to do a frack and we have community members who are out on the land who are very concerned about the activity, without any baseline information or anything to fall back on. So there is a rush for the LNG but we do have some time to do the right thing and to start collecting that information. We are trying to work with the B.C. government to put some plans in place that instill our cultural ways and that will sustain our way of life, so we have to add those values when we make decisions like this.

One thing that I think people really need to know is that the Horn River is where a lot of this activity has happened. Right now they're trying to move into the Liard Basin which goes all the way up to the Yukon Territory. So there are going to be a lot First Nations affected by these decisions and we need to play a central role in how we're going to move forward, working with governments like you in ensuring that we put in the highest level of environmental standards and find the gold seal for environmental protection, because it is really important that we work together, especially with the First Nation communities, to find the balance.

There are things that our people know about the land that I could never relay to you or that some people just don't understand when we get information from our elders in the way they communicate with us. A lot of the time we don't share any of that information. We set out areas where there are spiritual sites or there are burial sites or cabins and so forth and we don't share that information with industry.

Our people are fed up with giving this information to people and then it being used against them. So, it's not just about fishing at one spot in the lake — we use the whole lake. You can't just identify somebody's treaty rights by just saying that they fish and made a dry camp here, so we won't touch that area. There is a lot more to what people in our community are telling us. We keep that information and we work with the companies and we tell them where they can't go.

Over the past 10 years, there has been an enormous oil and gas boom and that was in the Horn River Basin. They are looking at developing up the Liard Basin, which is pretty pristine to me. I like to view it as untouched territory, when it comes to development.

Then we're going to talk about hydraulic fracking and the resources it uses and the amount of water. Right now, things are regulated by the Province of B.C. and they are paying no attention to the cumulative impacts, so the Fort Nelson First Nation is working hard to gather that baseline information and start the process before this gas starts flowing to Asian markets, if it is a go.

I will hand off the presentation to Lana and she will get into some of the more technical information that you guys are looking for.

Ms. Lowe: Good afternoon, everyone. We view shale gas and hydraulic fracturing as more than just fracking. It comes with a lot of associated environmental impacts that I'm concerned with, as lands director. There are also social and economic impacts that Sharleen can talk to later, but this presentation is focused mostly the impacts to land from fracking and associated shale gas development.

Our nation has been hit hard by shale gas activities in our territory; you saw the map of the three basins in our territory. The Horn River Basin has been the focus of most of the industry's activities and we have done a bit of analysis of the impacts and cumulative effects to date. We are looking at about 80,000 kilometres of linear disturbance — that's pipelines, roads, seismic lines — in the territory in the past 10 years.

We have seen a huge increase in actual well pads, well drilling and the associated water withdrawals required for fracking. We are also looking at three major pipelines that have been approved in the past seven years and are under construction or have been completed in our territory. We have five gas plants that are approved — four are built, one is just recently approved. We are looking at a whole swath of development across our territory.

So this was our territory back in 2006 before the shale gas boom came. Between 2005 and 2010-11, the B.C. government made billions and billions of dollars off land sales to oil and gas companies in our territory. We have an economic benefits agreement with the province that we have gained about 2.5 million dollars from royalty sharing. So we are looking at renegotiating that agreement.

This is 2006, and this is 2013. It is hard to see in this map, but the large patches are seismic exploration programs. There is an increase in roads and pipelines and actual wells, so it's a huge impact in a very short time and we're having a pretty hard time dealing with it all.

We've been working very hard with B.C. and industry to try to get a handle on this development because of the way the Horn River Basin unfolded on our landscape. We have seen some pretty unacceptable environmental impacts that we hope to get ahead of for this development to continue.

What we see here is just the beginning, and we're hoping, with B.C.'s LNG strategy, we have a few years at least to work with B.C. and industry to make sure that what happened in the Horn River doesn't happen again.

Some of the impacts we've talked about are to wildlife. I don't know if you guys have heard in the news, but recently on a seismic program, a black bear was run over by a mulcher and killed, so that's just one of the most disturbing incidents we've had to experience. One of the most disturbing things about the incident is the fact that the British Columbia government has no regulations, rules or procedures or policies in place to prevent such a thing from happening and there's no way to address what actually happened. The company has not been fined. There are no plans in place to prevent or to discourage such behaviour.

So we are actually working with the company to ensure that it doesn't happen again. We have a fairly good relationship with the company. They agreed to a stop-work order; it was just lifted yesterday. They hadn't worked for a week. They have purchased infrared cameras. They're going to mount them on helicopters and do fly-overs so that they can do heat-seeking to map out dens and flag them off so mulchers can't go over them any more. It's to a significant cost to the company, but they're doing it because we've insisted that this isn't going to happen again. We're hoping that the British Columbia government will step up and make sure stuff like this doesn't happen.

So those are some of the things we deal with. We're losing habitat — caribou, grizzly bear, buffalo. We're concerned what all these seismic lines are going to do, all the pipelines, all the roads — how it's going to affect our animals, and our ability to hunt the animals and to maintain the integrity of the land for their survival.

In northeast B.C., where the caribou herds are in our territory, prior to the Horn River Basin exploding in shale gas development, we had three of the most viable herds in the Horn River Basin and now they're all endangered.

We also have concerns about deforestation. The B.C. government doesn't have a plan for using all the wood and all the trees that are cleared for all the pipelines, gas plants and well pads. There's no processing plant close by so the companies are allowed to burn all the merchantable timber. We are hoping — I mean that's a simple policy change that we're hoping that we can force the government to implement.

It seems unacceptable to just burn trees to make way for oil and gas. We have concerns about deforestation and the loss of some of the rare plants and the food and medicine plants that we use.

We also have — again, government policy. We had identified some rare plants in an area that was slated for a gas plant, and the response from the B.C. government was for the company to just uproot the plants and move them. So there are things that are happening on the ground that really don't make sense to us and really don't do much to reduce the impacts of what we're seeing.

I think the Pembina Institute had done a presentation on GHG and gas emissions. We know what's coming. We know that each company is going to want their own gas plant to process the gas to get it to market. We would like to work with the B.C. government to say how many gas plants are too many gas plants, because we don't want to have an industrial sea across our landscape of gas plants. Hopefully, one of the things we would like to see is a cumulative effects assessment, some sort of land use planning — air shed mapping — so that we can start talking about how many gas plants the land can sustain. We also have concerns about air quality. A lot of our community members won't harvest plants or animals near industrial sites for obvious reasons.

We also have another part. A piece of the shale gas puzzle is frack sand mining. It's open-pit mining that produces silica dust, because the quality of the sand required for fracking is high in silica and that has been known to cause lung cancer. So we have serious concerns about frack sand mining in our territory. We're not interested in having it in our territory. The companies — we have talked to them and they say it's okay because the workers wear masks when they're around the dust, but I don't see the moose running around with masks on to stop from inhaling silica dust. We're already seeing cysts on meat when we hunt, so our people are starting to get really concerned about the health of the animals from air pollution near industrial sites — air and water pollution.

One of the most well-known concerns about hydraulic fracking is associated with water — both water contamination and water quality issues and water use — water loss. We have pushed the B.C. government to really consider what the impacts of shale gas and fracking are on our water systems, both ground and surface water. We do work with Dr. Gilles Wendling to help us understand the groundwater issues and we are trying to get our heads around water management in the face of shale gas.

We have 20 long-term water licence applications sitting in front of the B.C. government now. One has been approved. We appealed the licence, based on inadequate consultation and also the fact that, within five months of receiving the licence, the company had drained the lake that they had the licence to by one-third of its volume.

So we went through a hearing; the hearing wrapped up and we feel that the evidence shows very well that the B.C. government didn't consult us adequately. The science came out that they don't really have a way of understanding the cumulative effects of the high-volume water withdrawals that are being used in fracking.

There is a move to not license on smaller water bodies, like the lake in question that had been drained. It was a shallow lake; it was only 1.7 metres. They drained it by 53 centimetres, so that was a pretty small lake to be issuing a large volume of water withdrawal. We're hoping to work with the B.C. government to figure out the best way to manage activities in the face of shale gas, so that we can protect our rivers and our lakes.

We do have three big rivers in our territory. There is, I think, a movement to target the large rivers instead of the smaller bodies of water, but still, what we're seeing coming down the pipe from LNG is a 600-percent increase in drilling — 50,000 new wells — and all of them are going to require water.

All these blue dots — this is a map of all the water licences. These are temporary water licences issued through the B.C. Oil and Gas Commission and long-term water licences that are issued through the Ministry of Forests, Lands and Natural Resource Operations.

The Oil and Gas Commission is now being authorized to be regional water manager to actually issue long-term water licences as well. So the B.C. Oil and Gas Commission is in charge of all water allocations for oil and gas in our territory. Some people think that is the fox in the henhouse so, again, we have to find a way to work with the B.C. government to ensure that the water is managed properly.

Water contamination — this is the one that is in the news all the time. You see people lighting their taps on fire. There are chemicals used in fracking that are known carcinogens. Water contamination is a large concern not only during the fracking process but also during the transport and the disposal of the water that is used. So when they do the fracking, they take the water, they mix it with the frac fluids, they do the fracking, and then they have to dispose of it permanently. We have seen instances already of spills and pipeline leaks, and the impacts are immediate and widespread.

We had an incident in our territory. One of the companies had a spill and, within days, the trees along the creek that it got into started turning yellow and it went all the way down to the river. There is no way to prevent these things — there are no rules or regulations in place. B.C. would tell you otherwise, I'm sure, but there is nothing we can do to really prevent these from happening and there is no fine for the occurrence.

There are some holes in the way B.C. manages water and fracking. These are some of the reasons why the leaks happen.

Sharleen, do you want to talk about social impacts?

Ms. Gale: So, with the social impacts, we have seen a lot of newcomers to our town. We're a small community of 5,000, and we have 800 band members, about half on reserve and half off. With the development of any industry coming into a community, you see an increased amount of crime. There are a lot of health issues that come when it comes to sexual health and so forth, and we don't have the ability to have those professionals in our community. You have to travel out.

Another thing that I would like to mention is that the B.C. government is making a lot of money off this industry and with the royalties that come from the gas, but we're not seeing that trickle down into the small communities and especially to the First Nation communities that are very remote and don't have access to health care — where they have to travel four hours or so. The nearest facilities are in Fort St. John, which is four hours north and a lot of people travel all the way down to Dawson Creek and Prince George, which is about another 10 hours.

You see a lot of different things happening to the community and we have to look at ways on how we bring that to our community to get the services, especially for mental health and so forth. There have been a lot of cutbacks when it comes to looking after social health and we need to find ways that only don't service the urban communities but they really look at how they can work with the First Nation communities and so forth.

There are a lot of things to consider when it comes to social impacts. When they open up the roads, there are a lot of roads being built. On the first slide that Lana had you can see the thousands of kilometres of roads, and non-aboriginal harvesters and so forth come into our community and they are using these roads to hunt. There are about four guys in a truck and they all have racks in the back of their truck. This is our food. This is access to our berries and our medicines. It could be devastating, especially if the water is being contaminated and it is feeding our medicines and our plants and animals — that is our concern.

It is really sad for me to see one resource that we all need and that we all have in common. Our bodies are made up of 90-percent water, so to see us use one resource to gain for another resource — it just doesn't make sense to me as a First Nation person. I think that we really have to look at finding other alternatives to extract this gas, and really think about our communities and our way of life and how we can protect the land.

As the elders said, you protect the land, you look after the land, the land will look after you. We live in a beautiful country. I like coming up to the Yukon and I think that there is lots to offer when it comes to eating off the land. We live in a beautiful boreal forest and there is so much out there to offer. It is our grocery store out there. We try not to eat as much as we can at the grocery store. When I'm there I try to eat around the perimeter as much as possible.

Those are just some of the things that I think that people need to really think about — like the crime activity. I know for a fact that crime has reduced with the slowdown of oil and gas. It was an article that was written in the *Fort Nelson News* that talked about the decline in criminal activity. I guess there is a lot of equipment that comes with this. Industry has a lot of equipment like chainsaws and four-wheelers and you see a lot of that stuff go missing. It's always in the paper and so forth.

Most definitely I think it is health care that we really have to look at — the health care impacts. I'll be presenting next month at the First Nations Health Authority meeting in our B.C. caucus. We're going to talk about how we're going to work together with this huge development that they're proposing in the Liard Basin. We want to get ahead of the game on all fronts and start working with different organizations to protect our people and our way of life.

Thanks.

Ms. Lowe: Just another point related to what Sharleen just talked about. In 2009-10 when shale gas was reaching its peak, there was a controversy in Fort Nelson because the increase in workers brought an application in for adult-oriented businesses to be brought into Fort Nelson and managed by the regional municipality. That was one of the largest town hall meetings I've ever attended. People were against having adult-oriented businesses licensed in Fort Nelson. In the end, it didn't pass. Those are some of the things that come with industrial development.

So the effect on our rights as Fort Nelson First Nation — we are having a hard time practising our treaty rights in the face of shale gas because of all the development in our territory. It's harder for us to get moose and when we do get them, some of them are unhealthy. We're not able to drink from the rivers and the lakes and the muskeg like we used to. Everybody brings water out when they head out to the camps now and to the trapline.

We're squaring off with B.C. on proposals for permanent water intakes on the rivers which are large, 20-metre cement blocks that house pumps. We don't want to see that on our rivers when we go out hunting to the cabins. The harvesting of our food and medicine plants is getting more difficult. There are less and less places for us to go to access these things.

One of our trappers has two gas plants and it's on the intersection of two major PDRs — petroleum development roads — and now there's a frack sand mine being proposed for across the street from where his cabin is, so he doesn't go out there to enjoy it any more.

Again, B.C. has an LNG strategy. The B.C. Liberal government feel they were elected based on this platform. They've promised trillions of dollars of new money — investment dollars — and thousands of jobs for the northeast. So we did a little bit of a study looking at what that would look like to our territory. Based on the numbers, we feel 10 to 25 percent of B.C.'s shale gas will come from our territory.

We're looking at, again, a 600-percent increase in drilling. We obviously have concerns about that because of the way the B.C. government fails to regulate the industry adequately.

The regulatory framework in B.C., we feel, is not adequate to protect the land in the treaty. The Crown takes an incremental approach to regulating activity. There is a land use plan in place in northeast B.C. The plan basically leaves it wide open for resource extraction. We have a land use plan that we've developed. We would like to see nine percent of our territory off limits to development. This nine percent is a river corridor that encompasses most of our villages and the Fort Nelson River. We also have a couple of other protected areas that we've identified, but that leaves 91 percent of our territory open for, we hope, world-class, regulated development. It can't be all shale gas. We have areas that we'd like to see set aside as guide outfitting territories, so we'd like to keep the shale gas industry capped — I guess is how to say it. We'd like to put limits to the development — where it happens and how it happens.

We're working with B.C. on that. It's a bit of a struggle to get there. We'll see how it goes. There are no cumulative effects assessments being undertaken in B.C. in the shale gas fields. Everything is regulated well by well, pipe by pipe, road by road.

One of the reasons or excuses that B.C. uses to not do cumulative effects assessments is that there are no baseline studies, there are no regional monitoring systems in place, so we're really pushing for baselines. We're working with companies to try to get the baselines ourselves, sharing the information with the province, and we're forcing companies to buy water-monitoring stations, climate stations. We're installing them, we're gathering the data and we're sharing it with the province.

I feel like we're out of sight, out of mind. A lot of people don't know what's happening in our territory. They don't know what's happening in the north. A lot of people don't know that LNG is connected to fracking. We feel that it's up to us and it's part of our treaty right and responsibility to manage the land, so that's why we work with companies to gather data to hold them to higher standards than what the province is holding them to.

Inadequate consultation, accommodation — yes, the B.C. government doesn't do a very good job of that. But I don't really want to go too far into that.

Because we're out of sight, out of mind, we feel that we're experiencing the largest impacts and the least benefit. Like Sharleen said, we have to send our ladies out of town to have babies because we don't have enough doctors. We pay the highest natural gas rates in B.C. The benefits are flowing south and we're left trying to figure out how to deal with it. We're hoping that the B.C. government will work with us to strike a balance between benefits and impacts and limit the impacts and maximize the benefits.

We feel that this has been forced upon us as a community and as a First Nation. They sold the tenures without talking to us. They sent us letters saying that they were going to sell the tenures. We had 30 days to respond. They called it "unconventional oil and gas development." We didn't know what that meant. We certainly did not know that it meant everything we've seen in the past five years.

It is a bit of an environmental nightmare. It can't be described any other way. The impacts are far-reaching and deep, and they are going to change our history. They are going to change how we experience our land. It's not an easy balance we're trying to strike. We know it's happening. Once we started seeing what was happening and what the implications were, we said no — flat out no. It happened anyway.

Now we are trying to figure out ways so that bears aren't getting mulched and the rivers aren't drying up and the moose aren't getting hunted out. We feel the only way we can do that is by working with industry and government to make sure that the right things are put in place so that we can do cumulative effects assessments and we can regulate and limit where and how shale gas rolls out in the territory.

Applause

Chair: I'd like to remind the gallery that, while we are pleased to have you, we would like you to not participate in the proceedings. Thank you.

Ms. Gale: I would just like to close off before the questions start rolling in. It's important to know that there are four huge gas basins in British Columbia, and all of them fall under our traditional territory. The development that is happening in the Montney Basin is surrounded by the other Treaty 8 First Nation communities and that is where most of the development is happening in Fort St John. Three of the other gas basins and the shale gas activity that is going to happen are in our core territory. Those are the Liard, the Horn and the Cordova.

Our provincial government is focusing on her LNG strategy. She is promising people thousands of jobs and promising us billions of investment dollars to flow through our province. As we had said, we really feel that there is a real risk of uncontrolled resource extraction and little regard for the environment, so it is up to our people to protect our land and to protect our treaty rights and ensure that our elders, our trappers and our community members are very involved in how this industry is going to roll out onto the land.

I wanted to invite you guys to our community in Fort Nelson First Nation in April. We are looking at having an LNG shale gas summit. I would be honored to have you guys in our community and have a tour of our community, meet our people, enjoy some moose, our way of life and be involved in our cultural values.

We are going to be inviting over 300 people — First Nation leaders, provincial and federal governments. We're also going to be inviting natural gas proponents and anybody who is involved with the industry. Fort Nelson First Nation likes to listen to all perspectives and to take the information that we gather from professionals who are really taking an interest in finding out how we can work together.

As I mentioned earlier, we haven't said yes. We're not at "yes", but we really do need to strike the balance and figure out how we can work together in making sure that the environment is looked after and that we find the gold standard for environmental protection for this gas extraction.

One of the things that we've worked really hard on for the last year and a half is to really sit down with industry and to ask them to work with us in finding this environmental practice. Some companies are taking a little bit longer to get on board than some others. We have asked them to step it up and be industry leaders and to go beyond what the government is asking them to do. In order for them to have access to our land and to our resources, they're going to have to really sit down with the Fort Nelson First Nation and consult with us on a higher level.

We look forward to finding solutions, especially when it comes to the water, our berries and our medicine. We rely on that as Dena people, and our survival as Dena and Cree people is tied to our land and to our treaty. For generations, the land has sustained us. It's who we are and where we're from. It's our livelihood. It's our culture. It's our history. It's who we are. Without the land, we have nothing and our treaty confirms this.

So I think those are really important messages for your government to hear. Also, when you guys are considering doing something like this in your province, then I think it's very important that you work with the First Nation communities. I know that decisions like this take time. They don't happen overnight. There's a lot of stuff that we could share with you on what needs to be done before any industry comes into your province, especially when it comes to baseline information.

I did mention earlier about the First Nations. When you're working with First Nations, really keep an open mind because the elders and the community members — they have a way of connecting with the land. The things that they say are very meaningful. You might not understand how they get that information, but the land talks to our people. Sometimes when the elders tell me stuff, and I'm like, "How do they know that?" and sometimes I just ask.

One year, we had a very cold winter but no snow. In the fall time, the elders were telling us that we're going to have a really cold winter, but there's not going to be much snow and so forth. I couldn't understand how they knew, but the land talks to them. It was because the bees were building their nests close to the ground. These are things that our people have learned over the thousands of years of living off the land.

So I really advise you guys to really work with the First Nation communities and honour what the people are saying, because it's really important that you go back to the users of the land and the protectors of the land. These are huge decisions and they need to be a part of the decisions that your government is planning on putting forth, make sure that some of those dollars roll back into the communities.

I hear from our government that our kids are going to be looked after and we're going to get hospitals and this money is going to make sure the lights turn on, but we're not seeing it in our communities. Our people are living in poverty and there is an obligation that every government has to First Nation people when you're visiting, and this is our home. We have an obligation to protect our way of life and our land, so I hope that you guys really consider what the First Nation communities are saying when you make your decisions. Thank you for having us here today.

Chair: Thank you very much. The Committee will recess for 10 minutes and then we'll return to engage in some questions. Thank you.

Recess

Chair: Order please. The Committee is going to resume. We're going to start with questions from the Committee. My question is about the moose population and the comment that you made about the illness in the moose and, in fact, the specific — I think you mentioned — cysts. I'm wondering if this has been documented anywhere in the scientific community.

Ms. Gale: I know that the Treaty 8 Nations through, I believe, the Treaty 8 Tribal Association, have done a study, or they do have pictures of different experiences — and with community members coming in and letting them know their concerns. I would definitely direct you to contact Tribal Chief Liz Logan and ask her because she definitely has mentioned it in some presentations with the concerns that are coming from the community members from the other treaty nations.

We are also starting to do our own little projects where we're using GPS technology to take pictures of different things that are on the land, like berry patches, gravesites and so forth. I would just direct you to the Treaty 8 Tribal Association.

Ms. Lowe: We do get a lot of photos or actual samples of tissue or cystine meat. One of our goals is working with the B.C. government to start a program where we can get the meat tested. One of the difficulties we're facing with doing a science-based study of what is going on with the moose is the fact that we're so far away from the labs. Getting the tissue and the meat to a lab in time for it to be properly tested, studied and analyzed is expensive and difficult. We're trying to work out with the B.C. government a process so that all the meat we have in our freezer in the lands office has a place to go.

Ms. Moorcroft: Perhaps before you begin timing my questions, I just had one matter of procedure to raise.

As with the other presenters who have been here before the select committee, the Fort Nelson First Nation has a slideshow presentation that they've prepared and that will be posted on the website. Those who were here in the Assembly were able to read the slides but the presenters did not read them all, so there is some information that you may not have seen if you were listening on the radio. Some of it may be captured in our questions or you can later look at the slideshow when it is posted.

I would like to start my questions going back to some of the things you said about community impacts. I'd like to thank you for your presentation and also thank you for the invitation to travel to your area. I hope that we will have an opportunity to do that.

Did Fort Nelson First Nation or the Fort Nelson community have baseline community health status reports prior to development and what are your thoughts on how social impacts could be measured and managed?

Ms. Gale: A couple of years ago, we did a food study and our cultural revitalization manager put on the program. So with that program, they took samples of traditional foods — berries, fish, beaver — anything that community members wanted to provide a sample of. Then we tracked where the game or the plant was gathered from. Some band members decided they would also give hair samples and so with that we're going to use that one program as a baseline for our food security. It goes in line with what Lana was saying. We're trying to really get ahead of the game on looking at all aspects where this huge industry could have effects on our community members. That's why we'll be working with the First Nations Health Authority to start finding ways that we can work together to ensure our people are looked after.

At this point we are working with other organizations to try to find the answers and how we can move forward.

Ms. Moorcroft: Some of the reports that have been done have written about the boomtown effect, where there is rapid change and then increases in crime and violence. You mentioned addictions, sexually transmitted infections and so forth.

Have you observed more pressure on your social services for mental health or for policing and what advice would you give to other communities about responding to the boomtown effect.

Ms. Gale: With any development in any community, there come those kinds of effects. I think that altogether — it's like the community has to work with the First Nation communities to come up with a plan. We do work closely with the RCMP. We do have a lot of workers on the front lines to help community members with health care and so forth. Yes, of course, we've seen an increase in the numbers of dealing with clientele and our community members and so forth. I think, ultimately, you have a lot of different people from all over the world coming into your community and just kind of — a lot of people are coming into the community, but they're also leaving the community and coming back. So people aren't living there. They're transient, I guess, and they're not part of the community. We have to find ways to work through this, I guess.

It's almost like sometimes we are just — you deal with it as you go. So there are going to be a lot of things that happen in the future, because I feel that a lot of people will probably be living in the community with these new infrastructures coming. There are definitely going to be more jobs, definitely, so we're going to have to work with the First Nations Health Authority and with the Town of Fort Nelson to find ways to find solutions, I guess.

Ms. Moorcroft: I would like to ask about employment and education. What impact has the employment in this industry had on local education results or on graduation rates and what level of jobs are the First Nation people working in? How many of your First Nation members have found employment since the industry increased?

Ms. Gale: Our community members work in a wide range of jobs in Fort Nelson. Community members also work in the oil and gas field and band members do have companies. So it's really important for us to strike the balance between that and ensure that the development that does occur has huge high standards of environmental processes.

We, as a community, were one of the top employers in Fort Nelson through our administration, our school and our businesses. We take pride in education. We have a school that runs from kindergarten all the way up to grade 12. I think that for the community of Fort Nelson, we do have high graduation rates.

We are also very lucky to be so close to a lot of the services that Fort Nelson has to offer. A lot of our kids are going off to college and university and I think there is an opportunity for us to be able to provide more services in our community.

We do work with the Northern Lights College and, most recently in our community, we started a trades centre and we work with NENAS to provide training in our own community because that is one thing that we find hard — to send people away. People want to live in their community and they want to be a part of their way of life. So having those services in our community means a lot to our people. We don't want to go anywhere; we want to live where we always have.

Ms. Lowe: Part of the approach we are taking with the shale gas industry is working with companies so that it is our people who are employed in the environmental services piece of the puzzle. I find that, as we hold companies to higher standards, we have more baseline studies being collected — we are actually doing groundwater and surface water testing. We need to have people in those positions to do the work.

I feel that we are creating job opportunities from a land protection perspective. Even the hand-cutters — the guys doing the seismic lines — if we insist on more hand-cut around sensitive areas than mulcher, then we are creating more people hours on the land, but we want to create biologists who work for the First Nation and hydrologists who work for the First Nation and have a place for our kids to aspire to, rather than, "When I get out of school, I'm going to work for oil and gas." They'll work for our community and our department and they'll have a role in environmental protection.

Mr. Silver: I just want to start by saying how important it is to our public presentations here to hear from your First Nation. It's interesting to hear the other presenters speaking about how, according to science, risks don't have to happen, and then to have presentations from your First Nation government witnessing the risks and your attempt for balance.

There are a lot of great questions from the gallery, so I'll be brief. I'd like for you to expand on the consultation process with the B.C. government. Are you getting consultation without accommodation? Are you finding it difficult to even get consultation? Where is the breakdown in your opinion?

Ms. Gale: So right now, as I have told our Premier, Christy Clark, there's a lot of work do with the Fort Nelson

First Nation and there's a lot of things that are coming from our community members and our elders that they need to take into consideration. Her LNG strategy is not a slam-dunk and I know that the race is on for the LNG development. There is just so much that they need to take into consideration. Right now we're sitting at government-to-government tables with the province in trying to find solutions. Lana is actually sitting on the negotiation team. So we have been working with the province to see how we're going to work through this but, as I said, there's a lot of work to do.

I will allow Lana to elaborate a little bit on some of the things that we're doing.

Ms. Lowe: We have a consultation process agreement with the B.C. Oil and Gas Commission. We signed it in 2012, based on some outstanding promises that a higher level of consultation would occur. The consultation process agreement is focused on referrals processing only, so an application comes in for a well or a road or a pipe — comes through the B.C. Oil and Gas Commission — and it comes to our office and we have 20 to 30 days to review. That's not good enough.

The government-to-government table that we're sitting at with B.C. is designed so that we're at shared decision-making level above the B.C. Oil and Gas Commission level of decision-making, so that we actually set — we're involved in setting the objectives and the strategies going forward that the B.C. Oil and Gas Commission has to carry out.

Those aren't easy discussions to have and it has taken us a long time to even get to that level of negotiation with the province. They were quite happy just to have us down at the OGC implementation referrals level, but it's not working because, the way they make their decision, it is road by road, pipe by pipe. It's not an overarching landscape view, so we're trying to get above that and start really working with B.C. on land use planning, cumulative effects assessment, and really have a say in what's happening, rather than the decisions are made and we get to comment.

Mr. Silver: You did mention that you were going to be having a committee on health talks coming up in your First Nation. I was just wondering if you would be producing any documents there and, if so, can the Committee be privy to those?

Ms. Gale: What is happening is in B.C. is that the First Nations Health Authority has taken over First Nation health care, and we're going to have a B.C. caucus meeting and there will be about four in the province with each region. We call in a lot of different chiefs from all over B.C. and we meet and talk about health.

I talked to the chair, Warner Adam, and I discussed with him the issues that may be coming forth with this development and I really want to start opening up a dialogue on how we're going to deal with it in our community, so I'll definitely share that information with you. It's just the start. I think it's a very important discussion that needs to be had.

Mr. Dixon: In your presentation, Ms. Lowe mentioned that you have a royalty sharing agreement with B.C. and that it's obviously fairly modest. You mentioned there's a possibility of renegotiating this. Can you explain a little bit about how you arrived at that agreement, what went into it, and then perhaps what the next steps might be for changing it or renegotiating it?

Ms. Lowe: I wasn't involved in the negotiation of the agreement but I know a bit about it now because I am involved in the renegotiation.

The Treaty 8 First Nations in B.C. have had economic benefits agreements with the province. In 2009 or 2010, our community walked out of the one we had with B.C. because they felt there were some terms in it that were unacceptable.

We went back to renegotiation, and again, after living with the agreement for a year and seeing that in the formula used for the revenue sharing at the height of drilling in 2010 we received just over $1 million in revenue sharing — for reference, it costs about $10 million to drill one well, so we were seeing that the formula that we had signed onto wasn't really benefiting our community to the extent to which the impacts were affecting us. So it's back for renegotiation in light of the LNG strategy.

The downstream First Nations in B.C. have been entitled to environmental review processes of the projects in their territory and also large revenue sharing agreements with industry. We're looking to strike that balance where we want the same environmental considerations that the downstream First Nations have, as well as benefits agreements that are commensurate to the impacts that are occurring in our territory.

Hon. Mr. Dixon: So those are the agreements you have with B.C. Do individual companies — are they required to enter into benefits agreements with the First Nation, and do they? If so, how has that gone and what structure do they use?

Ms. Lowe: They're not required to enter into agreements with us, but they do negotiate agreements with First Nations as part of their social licence to operate.

In 2010, we signed two agreements with industry. One of them is open for renegotiation again because, in those days — which wasn't so long ago — we accepted agreements that said we had signed off on all the company's development in our territory for a certain number of years in exchange for $100,000 a year.

We find that unacceptable, so we're working toward agreements with industry that allow us a real say in what happens in the territory, that allow us to hold them to higher environmental standards than the British Columbia government does — the infrared seeking cameras, stuff like that. The new agreements will not be a blanket signoff on all development in our territory in exchange for a cheque. Some community members feel that's similar to welfare and is unacceptable.

So we are working to really have agreements with industry that give us the ability to have a say in their operations in our territory.

Ms. Gale: I'll just add to that. When we talk about the activity that's happening on our land, it's not about money — it's actually about protecting our way of life and who we are as people. To allow anybody to come on our land, we're really going to push hard on the environmental standards. We have also split up the Horn River Basin Producers Group, which was a group that was formed to work together on how they're going to build roads and how they're going to try to work together to minimize the impact.

What we have done is we've got back to the table and let them know that there is no Horn River Basin Producers group; that each company is responsible for their own tenure and to ensure that we work with them one-on-one directly to develop the landscape. Because, like I said, the B.C. government is pushing this development on us and we are standing up firm. As I said, we're not to "yes" yet and we will be having community engagement sessions, ramping that up with our community to ask them — how much is enough? What are your feelings about this? Are we going to allow this to happen? These are really important questions that have to come from our people. We'll take direction from our people and that's pretty much how we have to come to the conclusion of how much is enough.

So, really it's not about money. It's about protecting our way of life as Dene and Cree people. I'd just like to let you know that.

Mr. Tredger: Thank you, Madam Chair.

I'd like to thank our guests for coming. I found their presentation very moving and much appreciated. It cuts to the quick in many ways.

My first question is around harvesting and wildlife and the effects on the environment. Did the First Nelson First Nation have any baseline data at all collected on berries or medicinal plants, moose, waterfowl or fish? Was traditional knowledge incorporated into any of that? The second part to that question is, what impacts are people noticing on their harvesting patterns? What ability do you have as a First Nation to set and enforce healthy standards?

The final part is just a question — when I was in the Cochrane area down by Calgary — which, as you know, is being heavily fracked — one of the ranchers mentioned that his cattle — when they did an autopsy on the ones that had died, they had a gel-like substance on some of the organs and they noticed that also in the deer population nearby. I wonder if that is being noticed in your area as well or whether it was just different chemicals.

Ms. Lowe: Prior to the shale gas industry moving into our territory, we didn't have a lot of traditional use studies completed or knowledge contained in one place that was accessible. We took advantage of the environmental review processes of some of the major pipelines and gas plants in our territory to access resources to train our people to do traditional use research and build a database.

Today we have a traditional land use database — and an oral history project that preceded this initiative — that we have put together in a database that helps us map out areas of use and interest. That database was the basis of the land use plan that we created where we took that information, mapped it out, had some community consultations about areas for protection and we determined that the rivers and the village sites were areas that we absolutely didn't want any development in. There are other areas of high traditional use that we have put aside as a special management zone so that we can try to manage the industry in those areas, so that the traditional use values that are there are protected and alive.

So, yes, we do some of that work. It is a difficult process of gathering knowledge and sharing knowledge — and sort of quantifying who we are as people in that way is difficult. Sometimes we run into problems where it's used against us, but we do our best to protect our knowledge and use it in decision-making.

The gel around the organs — that's somewhat disturbing. But I've noted that because I'm going to — the hunters, when they go out next year, I'll ask them to take a look for something like that.

Ms. Gale: Just to add to that, we do get reports from community members about some of the concerns. We had a family who use this one certain spot and they get fish. They have reported that this one year was the first time they have never caught fish there in their whole entire life, and that was from an elder in our community. They've been going there — and his family has been going there — for thousands of years. Very concerning to him — so what he had done is he actually set up a net, because it just was unreal that he never got fish this year from that spot where his family has been going for many years.

So those are some of the things that we hear. There also is even a community member who was never able to cross a river out by his cabin. He made a video about the activity that's happening out on the land. It was the first time in his life that he actually drove across the river in a four-wheeler, and he said you could never ever do that his whole entire life.

Another thing that we have done is we have a land use plan where we get community members to identify certain spots for no-go zones. One thing that I want to be able to do is bring my grandchildren to the same spot where my grandma used to pick berries. I don't want to have that spot destroyed and have a gas plant set up there. I want to show my children these spots and what they mean to our people and how we ate there for many years. My grandmother sat in those patches and I feel such a spiritual connection when I'm in those patches picking the berries that sustained us for thousands of years.

There are many places out there that we keep to our hearts, and each community member has their own places, and no one — we won't allow people to take that away from us, so we are looking at — when we go work with the First Nations Health Authority, we are going to be asking for funding to ramp up those kinds of studies, because it's really important that we get the true picture of everything. Like I said, we're open to everyone's perspectives and we just hope that people, as you, are open to even the First Nation perspective and protecting the land and our way of life.

We're the keepers of the land and I think that there is a lot to learn from First Nation people, especially our elders.

Mr. Elias: Chief Gale and Ms. Lowe, mahsi' cho for your very powerful and moving presentation — actually — it was great. There are so many questions from the gallery and from Yukoners today that I'm just going to make a comment and maybe just ask one brief question, but I do have a lot of questions and thank you very much.

My boys and I travel down to your traditional territory maybe two or three times a year to play hockey. Over the years, I've noticed, and they've noticed, a lot of infrastructure development along — especially between your community and Fort St. John — not to mention navigating through the bison from time to time. The last time we went down, we stopped counting at 400 B-trains. I just couldn't believe it. The amount of escalation of oil and gas development in your traditional territory has grown exponentially, and I just couldn't image that happening in my traditional territory.

I think for a comment it's with regard to traditional knowledge and your relationship. I'll just use caribou for instance. If caribou become few and far between and a generation is not able to teach the younger generation traditional knowledge about that specific species, that's gone and no amount of money is going to bring that back. So please consider that.

To the question now: your organizational chart for your First Nation includes an economic development corporation branch in your organizational chart. I was just wondering if you could comment on their roles and responsibilities in advancing your government's goals and objectives with regard to hydraulic fracture stimulation, if any at all.

Ms. Gale: With our economic development corporation, we're actually just setting it up. It has been in operation for many years, but it's really hard to get people to come to Fort Nelson — to be living in the community — so we've had some challenges there. Ultimately, what it comes down to is community engagement. We need to talk to our band members on what they want.

What kind of companies do we want to own? We're not very interested at this point in setting up any huge companies until we get this information from our community members. Of course, there are a lot of people phoning and wanting to start partnerships and stuff like that. We're at the point where we need to go to our community and say, okay, what kind of businesses do we want to own?

I will let you know that we do have a construction company and we do build roads and so forth, so that's part of striking the balance in how we're going to develop the landscape.

There are a lot of our community members who do work in the oil and gas industry and, as Lana had said, we want our band members on the land. We want environmental protection for our land and we want to be able to have the same authority as the OGC, where we can just walk in — or the NEB — and say, well, "What are you guys doing today?" and have those discussions with industry.

We are definitely trying to strike the balance. We have a lot of community members that have worked in oil and gas since the 1960s. We had one of the biggest gas plants in our territory since then and that's the Fort Nelson gas plant on Mile 285, owned by Spectra Energy. We definitely are trying to strike the balance and that's what our conference is going to be about. We're going to allow for industry and government and First Nation groups to present at our summit. I think it would be a really good opportunity for you guys to learn more about the people who are planning on coming into your territory and to hear some of the concerns that are being brought forth by the communities that are involved in LNG and that are involved in shale gas extraction.

We're going to open up that dialogue and we're going to talk about it, and with the community engagement — I mean, that's where we'll take the direction, from our community — on how we're going to move forward with economic development.

Ms. Lowe: This goes to the comment about the children learning who we are. We know it's coming and we have seen the exponential growth and we know it's going to get worse, which is why we did the land use plan and why we're — the non-negotiable with the B.C. government is the nine percent protected river corridor with our village sites.

So we can have that place to be who we are and to teach our kids who we are. We have built some cabins out at one of the villages that are closest to our main village now. Part of my role as lands director is to provide opportunities for our people to be out on the land in peace and to be able to have healthy moose and fresh water to drink.

We do host moose camps, so we are trying to find ways to strike the balance where we have places to go that are important to us, that are historical to us, where our people have lived and died for generations. We want to hold that for us, so that industry can't come in those areas.

I don't think it's a lot to ask. I'm encouraged with the discussions with the B.C. government that we will actually have those places set aside for us. We don't like to use the words no-gos and set-asides, but it's the reality. We've been able to prove to them and show them what's coming in our territory with the shale gas B.C. LNG Strategy. We're trying to find our way through it all.

Chair: We are going to proceed now with questions from the public gallery. I am going to ask the first question. Jacqueline Vigneux is asking if you are in contact with the regulators. How many regulators? How many wells?

Ms. Lowe: The B.C. Oil and Gas Commission is the regulator. We have a consultation process agreement with them. We don't have a high-level relationship with them at this point. It's not strategic. It's not planning. They are the regulator. It is their job to regulate the industry and they approve all development related to oil and gas. We have an opportunity to comment on the applications coming in the door. They are also responsible for compliance and enforcement. They have one compliance and enforcement officer in the north, so we feel that is unacceptable again. They do permit well by well, road by road, so there is no way for them to really regulate the industry in an effective way.

Ms. Moorcroft: I have a question from Jacqueline Vigneux. Do you know how much water the industry Apache used to frack wells in the Liard Basin?

Ms. Lowe: Apache has two wells in the Liard. The numbers vary regarding how much water is used per frack. They are permitted to use water through the B.C. Oil and Gas Commission, which is a temporary, short-term permit. The permitting reporting structure is somewhat difficult to navigate so we really don't know how much water is being used.

Ms. Gale: I would just like to add to that. Lana had mentioned that there is a huge concern about the water usage in our territory. She did mention that there are 20 permanent water licences on the table. What they're looking at doing is putting permanent water structures in our rivers, and our community members are saying no. We are in discussions with a company that has a proposal on the floor to build one of these infrastructures, so we're really creating awareness on that and saying no, we don't want these permanent infrastructures in our rivers. Our people don't want that and they don't want to see it. We want to enjoy our rivers the way they are. So we're really trying to find solutions.

Band members are very concerned that they can't go out and scoop up water like they have for thousands of years and make muskeg tea. Some of the elders don't even want to eat any of the medicines because they're very concerned about whether or not it's contaminated or not, right. So, water is a huge concern, water usage is a huge concern, and hopefully we can find a way so that we understand the amount of water that is actually being used. What we're told is that, for one frack, it takes four Olympic-sized swimming pools, which could take up to billions of litres of water, so just imagine all those water bottles piled up there. That water is being taken out of the ecosystem and not being put back.

It's being pumped into the ground and capped off, and we're being told that it won't affect our groundwater. Like I said, there is a lot of work to do and there are a lot of considerations when it comes to fresh water. We all need water. Water is life.

Chair: Mr. Silver, last question please.

Mr. Silver: This is from Rob Lewis. If you could go back to 2006, what would you do differently?

Ms. Gale: That's a very, very good question. I think that if we had the information that we have now, I think there would have been a lot more pushback because, like Lana said, we didn't know that the government went and sold our land. This was forced upon us. Putting these projects where they are piecemealing them and we're just getting permit by permit for these projects — they're not taking these projects and putting the full throttle of what they actually are. The LNG strategy — you know it's a pipeline. It's going to be running through this many communities and it's going to be this many kilometres long. For the shale gas extraction, industry has difference pieces of land where they are developing, so everything is just piecemealed and it's not showing a true picture of what exactly is going to come.

Now that we know what we know now through the Horn River development, plus working with other organizations and professionals, we've learned so much; we know what needs to be done. I think it's important that we're really creating awareness about what's happening in northeast B.C. We're very concerned, and like I said, we're Dena and Cree people and our land is our way of life. If we don't have land, then who are we as a people?

We have to be able to instill our cultural values and to live life as we formerly always have. It's a peace and sharing treaty, and I think that people need to come together to find solutions, because it can't just be what had happened in the Horn. We're really looking at how the Liard is going to be developed. Like I said, we're open to perspectives; we're open to working with different organizations to help us find the solutions, because we can't just be left with all the impacts and our people left to suffer. There are great considerations that need to be made.

That's one question that I would definitely ask my community. If we knew what was going to happen, what would we do differently? Those are questions that I will be asking the community, because it's a very good question and I would like to know the answers from the community members.

Chair: Any closing comments, Ms. Lowe?

Ms. Lowe: If I could go back to 2006, knowing what we know now, like Chief Gale says, there would have been a stronger pushback for sure. We have gained so much knowledge and understanding of what's really going on in our territory and what the impacts are and implications are.

I would have liked to have had that information and a very serious discussion, not only with our community, but with all of British Columbia, to ask people — is what you really want?

There's a lot at stake, a lot to be lost, and it is there. The benefits, sure they're there. They're huge. B.C.'s going to get rich and everybody is going to have great jobs, but the costs are pretty high and I think that it is a serious public dialogue that needed to happen before this came to be. That's why I commend the Yukon government for taking the time to have this discussion and really take this issue seriously, because it's not just one well, it's not just one road, it's not just a slashing job. This is serious environmental impacts, cultural, social. It's a turning point in our history and it needs to be taken seriously. These decisions can't be made by some guy sitting in Victoria at his desk ticking off checkboxes.

If we could go back to 2006, I think there would have been — there should have been — more public understanding, knowledge and debate.

Chair: The time for questions has elapsed and I want to thank Chief Gale and Ms. Lowe for coming and joining us today. I want to thank the visitors in the gallery and the Committee will be looking at the remaining questions that we didn't have time to answer and trying to get you some answers to those questions.

Just before we recess, Chief Gale.

Ms. Gale: I would just like to close off and really invite you guys to the summit. I think it's a really good opportunity to see how the activity is rolling out on our landscape and how our technical team and our administration is trying to work with industry and government to ensure that the highest environmental standards are put into place before any of these huge projects come. We do have time; it takes about three to four years to build this LNG facility.

I think it would be really good for you guys to see, because we have some of the same land. And we are just next door. We look forward to having you guys in our community and to see who we are as people and maybe really understand what we are trying to say, because this isn't about money — this is about protecting our way of life and who we are, and we would like to share that with you.

Chair: Thank you, Chief Gale. The Committee will recess for 15 minutes

Recess

Chair: Welcome 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'd like 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, 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, Minister of Environment, Minister of Economic Development and the minister responsible for 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 have had several presentations over the last two days — and this being our final presentation — 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 from the National Energy Board: Abul Kabir, Drilling Engineer; Gary Woo, Program Manager; and Patrick Sprague, Director Northern Applications.

The National Energy Board is an independent federal agency that regulates pipelines, energy development and trade. Following the presentation, we will take a short recess before proceeding with questions. At that time, we invite visitors in the public gallery to submit questions. There are forms and pencils at the entrance. The page will collect the questions shortly before the end of the presentation. I'd like to remind you that the proceedings are being recorded and transcribed, and if your question is selected, the information you fill out on the form may be read into the public record.

I have reminded all Committee members and I'd like to remind the presenters today that if they could indicate to the Chair who will be responding to the question so that the Chair can recognize you and have your mic turned on, that would be great.

I ask the visitors in the gallery to 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.

Mr. Kabir: Thank you for the opportunity. I will cover the first part of the presentation and Gary Woo is covering the second part. We are here to discuss some of these hydraulic fracturing operations and some of the risks and concerns. We will also touch on some of what we can do as a regulator to address some of the concerns.

What is in our presentation today? We'll talk about hydraulic fracturing operations. Our staff was engaged in various community consultations where they heard from the community and what their concerns are.

NEB has a mandate for safety and environmental protection, so we'll discuss what the safety risks are and environmental issues involving hydraulic fracturing, and we'll also highlight the regulatory framework and NEB's role in regulating hydraulic fracturing activities.

Before we discuss our hydraulic fracturing operation, I'd like to highlight a point — why we need hydraulic fracturing in the first place. There are hydrocarbons present in various rocks in subsurface formations. Some are conventional, some are unconventional.

Usually the limestone, dolomite and sand formations and conventional formations — they are porous and permeable rocks. What does that mean? The hydrocarbon presence inside the rock — in the porous void space — and those pores are interconnected. So when a company perforates hydrocarbon rock, conventional rock, it flows by itself.

On the other hand, unconventional resources usually are shale formations. There are pores and there are hydrocarbons, but the pores are not connected. Their permeability is very poor. It requires fracturing stimulation to create the flow path. So what does it mean? There is an artificial way the company creates the flow path so that oil and gas escape from the pores to the wellbore and to the surface.

Horizontal drilling and multi-stage hydraulic fracturing are the common technologies used to extract hydrocarbon from tight rock or shale formations.

So what is hydraulic fracturing? For shale oil and gas recovery, it requires hydraulic fracturing.

This well-stimulation process involves injecting high-pressure fracturing fluid into the rock. The rock is under overburden pressure and it requires hydraulic pressure to frack open the pores. Once the pores are open, hydraulic fluid is pumped into the rock. This fluid contains water or oil, proppant — a kind of sand — and various additives. The proppant keeps the fractures open and allows the hydrocarbons to flow to the wellbore. So once the hydraulic pumping is done, pressure is released — we call it "flowback" — the company calls it "flowback" — and hydraulic fluid starts to flow from the rock to the surface. One of the mechanisms to keep the permeability active, or pores open — whatever proppant or sand is pumped inside the rock, it needs to stay there to create artificial permeability.

Some proppant might come back and the flowback fluid contains the fracturing fluid and the reservoir fluid and the fluid inside the wellbore. This is a simple illustration of the process. Water, sand or proppant — and then it is mixed on the surface, pumped at a high flow rate into the wellbore, frack open the rock and stimulate the reservoir rock. Once the pressure releases the fluid from the rock, along with the frack fluid, it returns to the surface. Sometimes it requires artificial lifting because of the low permeability situation. Once the fluid returns to the surface, the gas is easily separated from the fluid and flared off. The fluid contains the frack fluid and oil. That oil and the contaminated frack fluid need to be managed on the surface.

There are a lot of concerns about fracturing fluids, so I will talk a little bit about the fracturing fluid here. As I said earlier, it contains water, sand and additives. This is a simple slickwater fluid example. Typically more than 99 percent is water and sand, and less than one percent is additives. What are the additives and why are they used here? Some of the additives are used as friction reducers. The objective of this hydraulic fluid pumping is to get maximum pressure into the rock — not to lose pressure inside the wellbore or in the equipment. The purpose of the friction reducer additive is to reduce the pump pressure between the fluid, the wellbore and the equipment.

Biocides prevent biodegradation of fracturing fluids during storage and during pumping. Corrosion inhibitors are simple; they prevent the corrosion inside the tubulars, equipment and pipes. Gelling agent — so when companies try to mix water and sand together, it doesn't mix. It needs some kind of viscosity so that the proppant or sand can suspend into the fluid and it carries from the surface into the wellbore — the target rock.

Clay stabilizer — usually unconventional rock is shale, and when shale comes in contact with water it tends to swell. The objective of using this clay stabilizer is to prevent the swelling. There are other types of foam-based and oil-based fracturing fluids, but it's very common, this slickwater fluid.

This is the layout of a typical hydraulic fracturing operation. It has a monitoring van, mixing facility, wellhead, sand storage, flowback fluid storage and some water tanks and fluid storage tanks.

As I mentioned earlier, NEB staff engaged in various community consultations and they heard various concerns about hydraulic fracturing operations.

Here are some of the highlighted concerns: surface water and groundwater contamination; volumes of fresh water used in hydraulic fracturing — usually the conventional well stimulation does not require as much volume as unconventional reservoir stimulation; and composition of fracturing fluids.

We talked about the additives. What are the additives? What sort of chemicals are they? What is the percentage? What kinds of additives are used?

Also, spills of fracturing fluids and flowback fluids. We are talking about volume, high-pressure pumping and high-rate pumping. What is the probability or chance there will be a spill?

Also, hydraulic fracturing-induced seismic activities — because of high-pump rate and high pressure, it cracks the formation, whether this formation is creating some kind of artificial seismic activity.

Air emissions — hydraulic fracturing, because of this low permeability rock, requires extended flow test. So what are the cumulative effects from the gas burning and what are the emissions? Also, there are a lot of logistics and transportations, so what are the impacts?

Environmental footprint — because of the nature of the rock, it requires more wells and more well pads to develop the fracturing field. So the more wells that companies drill and the more well pads they build, it creates more environmental footprints. Gary will cover these three slides. I will skip these three slides now.

Other than the company, our consultation with the community — we look into other jurisdictions and look at different literature, and also we developed a hydraulic fracturing filing requirement. During this process, we came across some of the concerns and hazards.

Here are some of the highlights: high pressure equipment involving hydraulic fracturing operations; storage, handling, mixing large volume of stimulus fluids; fracturing fluids and it's composition; fracturing fluids volume and high pump rate; fracturing stimulation pressure on casing integrity; extended formation flow testing; flowback fluids; contain, storage, handling and transportation of flowback fluids; storage and transportation of reservoir oil; and flaring reservoir gas.

So you can see our study is coincided with the community concern as well. This was the foundation of our filing requirement for the drilling operation involving hydraulic fracturing.

Now we talked about the hazards here. If something does not go wrong, there will be no effect on the environment and safety. If something happens, there's supposed to be risk probability for the impact. So for the next few slides, I will try to go from hazard to risk and how it impacts the safety and environment.

To talk about this risk — safety and environmental risk — NEB has a mandate for safety and environmental protection. I like to group it into two categories: one is on-surface and the other one is subsurface. One is above ground. We can see another one is below ground. It's hard to see.

We have to imagine a lot of parameters. So it involves high-pressure equipment failure. If the equipment fails, then there might be a leak and spill from the storage tank. Number and size of the well pads — if we have more well pads, more numbers of wells drilled, the environmental footprint will be larger.

Additional logistics compared to normal drilling — because of the high volume — we are talking about thousands of cubic metres of fracturing fluid and an extended flow period, so there are more tracking, bulk storage tanks and bulk transportations. If I summarize the possible impact or hazards to the surface environment, surface water contamination is slightly different from the groundwater. Groundwater — we'll talk about that one later. There is a larger environmental footprint and, because of the high activities, injuries.

The next part is the subsurface hazards. What are the risks that can come from the subsurface hazards? So, well integrity may compromise because of the high pressure. We are talking about three, four, five times more than the normal operating pressure.

Excessive fracture propagation — the company designed the frack's growth and how far it can grow, so manage the fracture propagation growth so that it does not communicate with casing, the natural frack or to the groundwater.

Well contour failure — there is a reservoir, it has a pressure, then there is a hydraulic fracture and during the flow — drilling, completion and flowback stimulation — all that time, there should be a well control. If it fails, that could create some environmental risk.

Extended formation flow testing and flaring — why does the company need the extended formation flow testing? Because of the low permeability of the rock, it requires more time to flow from the rock and understand the rock's characteristics and rock's productivity. In conventional oil, usually there is a couple of days' of flow testing — could be a week — but in this case — in unconventional resources evaluation — it might take months or even a year.

High volumes, high pressures and high pump rates — so what are the impacts on the wellbore casing cementing? If something goes wrong with these hazards, the impact could be groundwater contamination from fracturing fluid, stimulation fluid or the reservoir fluid and potential induced seismic events. During the frack operation, it creates high energy and could trigger some kind of seismic activity. So when we talk about the groundwater, we mean the subsurface fresh water.

In this part I will discuss in brief regulating shale oil and gas activities, and how the pieces fit together. There are various mandates: rights management, land use permits, and operations authorization and well approval. Aboriginal Affairs and Northern Development Canada has the mandate for rights management. Some of the elements are exploration licences, significant discovery licences, production licences, benefits plans and royalties.

The land and water board has jurisdiction for land use permits, water licences, environmental screenings and assessments. Actual work or operation is under the National Energy Board's jurisdiction at present. Some of these authorizations are exploration and production authorizations, geophysical authorizations, well approvals, drilling, completion and hydraulic fracturing, significant and commercial discoveries, and development plans.

One of the features of this regulatory framework is separation of the oil and gas rights and financial interests from safety and protection of the environment.

This slide is a summarized flow process of an application review. Companies submit the information and authorization application. Some of the elements are: safety plan, environmental protection plan, declaration of applicant, certificate of fitness, and proof of financial responsibility. All of them are covered in the filing requirement as well.

Our technical team reviews the applications. They assess and make recommendations to the board for their direction or decision. Before recommending, we require environmental screening approval, environmental decisions from land and water board, and the benefit plan from Aboriginal Affairs and Northern Development agency.

The board decides whether they will approve or grant the authorization with terms and conditions. Authorization may be followed by well approval, and we do the similar technical review and assessment.

The NEB regulates a project from start to finish. What does it mean? It covers the life cycle of the project — the application phase, decision phase, operations phase, compliance verification until abandonment.

Some of the elements we look at in the application are the management system — whether the company has a technical and financial capability to do the work safely while protecting the environment; the safety plan; environmental protection plan; financial responsibility — if something goes wrong with it, the company has a financial capability to address it; environmental screening; and benefit plan.

In our operational phase and compliance verification, we had reports, we reviewed the reports — drilling report, well operation report, well history report.

We have an inspection process for various types of inspection: environmental inspection, safety inspection and integrity inspection. Environmental inspection looks after whether the company meets the environmental protection plan they submitted. The safety plan — safety inspectors look at the operation and safety plan compliance and integrity looks after the operations if there is any problem with the well integrity. If required, NEB can contact the owners as well.

In the *Canada Oil and Gas Operations Act*, NEB has jurisdiction, highlighted in yellow. This is present status. NEB has a mandate for safety, protection of environment and conservation of resources. Under this act, for drilling operations, including hydraulic fracturing, we have regulations — *Canada Oil and Gas Drilling and Production Regulations*. For specific requirements, we have the *Filing Requirements for Onshore Drilling Operations Involving Hydraulic Fracturing*. To develop this hydraulic fracturing, we included all the concerns we heard from the community and also some of the studies we conducted in-house.

Now I'll talk a little bit about the onshore filing requirements for hydraulic fracturing. In September of last year, NEB listed this filing requirement. This is the board's expectation — when a company wants to submit an application to drill a well for hydraulic fracturing, this is what they need to include in their application. It also addresses issues and concerns we heard from the community and general concerns we found from studying in various jurisdictions and activities.

The filing requirement has various requirements. I would like to make two groups. One group already exists in the act and regulations. The other part is very specific to hydraulic fracturing. The first one is filing requirements set out in the *Canada Oil and Gas Operations Act* and its regulations, especially in the oil and gas drilling and production regulations, and the safety plan guidelines and environmental protection guidelines.

Some of the elements are a management system, safety plan and environmental protection plan. When we talk about the management system, we want to see the company has the technical financial capability and management system to do a job safely while protecting the environment. Safety plans need to meet the requirement for safety plan guidelines under drilling and production regulation and also Canada oil and gas health and safety regulations. Environmental protection plans need to meet the requirement of environmental protection plan guidelines under drilling and production regulations. The safety plan and environmental protection plan is the protection part of the operation. If something goes wrong, what is the company going to do? That's why they need to submit an emergency response plan. If something goes wrong, how are they going to address the emergency?

Companies must submit details of risk assessment — what are the hazards? What are the consequences? How are they going to meet the risks? Canada Benefits Plan — this is by Aboriginal Affairs. Financial responsibility — if something goes wrong, will the company have the financial capability to deal with the consequences and compensate? Declaration by applicant — the applicant is to declare all equipment is fit for the purpose. If required, they need to submit the fitness certificates to demonstrate the equipment is fit for the purpose. Also, we do the inspection to ensure some of the activities are safe to conduct.

The second part is requirements specific to hydraulic fracturing. Some of those elements include: identification and protection of groundwater zones. If the company wants to protect the groundwater, they need to know where the groundwater is. I'm talking about the freshwater zone. Where is the top of the freshwater zone? Where is the bottom of the freshwater zone? Is there any solid formation below the groundwater zone? So that when they design the well and integrity, they consider all those parameters of well design and integrity related to hydraulic fracturing. So when they identify the groundwater, they need to set the surface — for example, surface casing below the groundwater so that the groundwater is protected.

Hydraulic fracturing modelling, execution and evaluations — this is one of the concerns of the fracture propagation: how far can the fracture go — whether it is communicating with the natural frack or it is communicating with casing or the cement — cement leakage.

Extended formation flow tests — we discussed that one earlier. Chemical usage, discloser and waste management — when the company applies for a hydraulic fracturing operation, they need to identify the chemicals they are going to use, how they selected those chemicals and their selection process. Gary is going to discuss about the discloser and FracFocus in a moment.

Waste management — for the extended flow test and high-volume injection, the company can expect a high volume of waste. It contains fracturing fluid, wellbore fluid and reservoir fluid, so they need to demonstrate how they can manage those on the surface safely.

All-season well pads — as you know in the northern territories, it is a winter operation. If they go for an extended flow test or production, they need to access the well pad all season, so how are they going to deal with operation during the summer?

Inter-well distances on multi-well pads — if they drill more wells for the same oil pad, the wells need to be spaced out during the hydraulic fracturing operation and production. Those wells should not communicate to each other.

I talked about the filing requirement. This filing requirement is designed based on the community concerns and some of the studies. Among the main features of this filing requirement is the groundwater protection. I just bring this one as an example to illustrate the filing requirement and what is inside the filing requirement.

One of the requirements is to identify groundwater and permafrost. As I said earlier, to protect the groundwater, it needs to be identified. Where is the location?

Identify possible groundwater contamination pathways — in the blue, you can see this is designated as groundwater and the production casing zone could be the reservoir section. From reservoir to groundwater zone is quite a distance, but what are the pathways by which this formation fluid, or frack fluid, could reach the groundwater? The company needs to identify those pathways. For example, one of the pathways could be the casing annulus. If there is bare cement, it could leak through the cement and go to the groundwater, but if they have a robust design and multiple casings, the risk could minimize.

Either way, if the frack propagation is too big, it could communicate with the natural frack — or the natural fault — and communicate to the groundwater. But, if the reservoir is further away from groundwater, the risk is lower. The surface casing needs to set all possible groundwater zones. This is one of the objectives of surface casing design — to protect groundwater.

Well control barriers need to be in place for all the time during hydraulic fracturing, flowback, drilling and completion. They need to demonstrate the well barrier is sufficient, not only inside that production tubing, but also the outside of the casing — both ways are protected.

Here, I'll conclude my presentation. I'll hand over to Gary for his frack chemical disclosure presentation.

Chair: Thank you very much. Mr. Woo, you have about eight minutes remaining.

Mr. Woo: Thank you, Kabir. I also want to thank the Chair and the select committee for allowing National Energy Board staff to present on how we regulate hydraulic fracturing.

The goals of COGOA, which we regulate under the *Canada Oil and Gas Operations Act* — the two top goals are safety and the protection of the environment. The public disclosure of hydraulic fracturing fluid chemicals through FracFocus is in line with those two goals. The board recognizes the importance of the public disclosure of hydraulic fracturing fluid chemicals to northern communities and to Canadians.

To assist in that, I'll just give some background on FracFocus. FracFocus.org is a website created by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission, both based in the U.S. to allow U.S. oil and gas operators to have their fracturing fluids disclosed on a public website.

I believe that website was put on-line about April of 2011. In about the end of 2011, the B.C. Oil and Gas Commission obtained the rights from the Compact Commission and the Interstate Oil and Gas Compact Commission to create the Canadian version, FracFocus.ca.

As I mentioned, the Board recognizes the importance of public disclosure of fracturing chemicals. On November 27, 2013, the National Energy Board signed an agreement with the B.C. Oil and Gas Commission, the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission to participate in FracFocus.ca.

The Board has requested all regulated companies publicly disclose their hydraulic fracturing fluid chemicals on the FracFocus.ca website 30 days after the completion of their hydraulic fracturing operation. That's in line with both Alberta and British Columbia.

The Board anticipates high participation on this. The public disclosure of hydraulic fracturing fluid chemicals is one of the CAPP — that's Canadian Association of Petroleum Producers — guiding principles on hydraulic fracturing. In addition, many of the operators that operate in the Northwest Territories also disclose their chemicals on B.C. and Alberta currently.

Since the announcement in November, the NEB staff have been working to get the computer systems working with the B.C. OGC to have our systems all in line with FracFocus.ca. We expect to be on-line by late this month or early March, and this would allow any of the frack fluid chemicals of the hydraulic fracturing operations currently being conducted in the Northwest Territories to be disclosed 30 days after the operation is finished.

Currently in Canada, the B.C. OGC, Alberta Energy Regulator and the National Energy Board have joined FracFocus and have operators disclose their hydraulic fracturing fluid chemicals on FracFocus.ca. In the U.S., 14 states use FracFocus.org as their official means for public disclosure of hydraulic fracturing fluid chemicals — and that's all I had for that section.

Chair: I want to thank you very much for your presentation. The Committee will adjourn for about 10 minutes and then we'll come back and engage in some question and answer time.

Recess

Chair: Order please. We are going to proceed with questions. As mentioned earlier, I would appreciate it if you would indicate to the Chair who will be responding to the question or if more than one will.

We are going to start our questions with Ms. Moorcroft.

Ms. Moorcroft: Thank you for your presentation and for being here to make this presentation to the select committee. I am going to start in the area of environmental assessments. Does the National Energy Board support the conduct of unique environmental assessments in unique territories in each jurisdiction or do they think it may be appropriate to use environmental assessments that have been conducted in other regions or jurisdictions?

Mr. Woo: Thank you, that is a very good question. In the areas where much of the shale gas, shale oil — it's in the Northwest Territories, where its environmental process is subject to the *Mackenzie Valley Resource Management Act*. As in one of the slides that Kabir presented, it showed the land and water boards.

We rely on their process for the environmental assessment. So if it's in the Gwich'in area or the Sahtu region, we use their environmental screening — or the Mackenzie Valley resource — the Mackenzie Valley Environmental Impact Review Board processes for the environmental assessment.

Ms. Moorcroft: What information do you have in relation to permafrost, and do you think that there should be a cautious and comprehensive approach for drilling in permafrost? What level of background groundwater data do you think should be available prior to development?

Mr. Woo: Yes, in many of those areas in the central Mackenzie there are regions of discontinuous permafrost. We work with the land and water boards to ensure that they have the operators verify the groundwater and permafrost and, through their operations, have the casings set below permafrost and the groundwater — the lowest point of the groundwater.

Ms. Moorcroft: What are your views in relation to who should have the authority to licence in the Yukon when it comes to down-hole injections — a process through which companies put the toxic fluid byproduct of drilling into a deep well? Do you have any thoughts on that?

Mr. Woo: I can't fully comment on the Yukon, but in our jurisdiction it's the National Energy Board that regulates the down-hole injections. In addition, as I mentioned, we would work with the land and water boards where the proposed activity would occur.

Ms. Moorcroft: The National Energy Board has a role in regulating a number of areas and one of the requirements that you spoke to briefly was financial responsibility. Governments have asked companies for security bonds — money set aside to ensure there are funds to deal with negative impacts from the resource extraction, should they occur, and there is certainly anticipation that hydraulic fracturing would have long-term impacts.

What is the industry norm with respect to security bonds and what is an appropriate amount of financial security? How is that determined when it comes to hydraulic fracturing?

Mr. Sprague: What we do is look at every application on a case-by-case example and financial responsibility is determined hand-in-hand with the risks and the mitigation strategies of that particular application. So there isn't a set number that we would expect for financial responsibility for the funds to be set aside, but it is rather a tailored approach to each application that we assess.

Mr. Silver: Seeing as there are many good questions from the gallery and we've spent a lot of time with regulators over the last few months, I just have an opinion question. I want to ask which jurisdictions do you think have the best approach entering into this industry in terms of development permits, baseline data and social licensing in your experience?

Mr. Sprague: That is a really good question. We were actually instructed that we're not up here to share that kind of opinion as the National Energy Board. You can take a look at everything that we've produced and the documents that we have talked about to see where we go and look and get our advice and our expertise to see what our opinions might be on that. But, it wouldn't be appropriate for us to comment on our opinions that way.

Hon. Mr. Dixon: I thank you. We've met with one company that's done some work in the Northwest Territories and I assume it has been regulated by yourselves. It's MGM, near Norman Wells.

How many wells have been completed with hydraulic fracturing in the area that you regulate to date?

Mr. Kabir: MGM drilled one vertical well with very limited fracturing. It was not a multi-stage horizontal fracturing.

Hon. Mr. Dixon: We've heard a little, of course, in your presentation about some of the specific regulations related to permafrost. We've also heard, though, that while measures can be in place to cool the casing and to try to keep the temperature at a certain level, my question is about the gas coming up. It's coming from a very great depth, so naturally it is going to be warmer.

How do you prevent the gas coming from great depth, which is obviously going to be warm, from melting the permafrost?

Mr. Kabir: During drilling, they use the drilling fluid so that when the drilling fluid circulates back to the hole, it is easily cooled down on the surface. That's the way they maintain the drilling fluid temperature so that it does not exceed the temperature that could melt the permafrost.

Mr. Woo: Just to add, from the production phase, you can have the low thermal conductivity cement as part of the design. In addition, at the production stage, as Hon. Mr. Dixon mentioned, from gas production you could have active and passive refrigeration to protect the permafrost from thawing.

Hon. Mr. Dixon: So given that we only have one well that you said has occurred so far — and it's obviously not in production yet — how do we know that is going to work, that those measures are going to protect the permafrost from melting as a result of the gas coming from great depths?

Mr. Kabir: So this is best industry practice.

Mr. Woo: Just to add to Kabir's answer, we only had one well, as you mentioned, in MGM, which is unconventional, but we also regulated in the ISR, the Inuvialuit Settlement Region, where they have a greater likelihood of permafrost, and in some of those wells, the proposed plans have been utilized.

Hon. Mr. Dixon: So there are no producing wells to date that use that low conductivity cement to prevent the permafrost from melting currently?

Mr. Woo: Yes, there are no wells that are producing, but in the Mackenzie gas project where there was permafrost — those were the proposed mitigation measures.

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

Mr. Tredger: I have just a couple of questions on disclosure of chemicals. Is disclosure of chemicals used in fracturing — the additives to the water — voluntary or mandatory?

Mr. Woo: Under our legislation it is voluntary, but we do anticipate high participation by operators.

Mr. Tredger: Further to that question, are the companies required to disclose the concentrations, the percentage of chemicals that they're putting down, or just that they're putting a particular chemical down? And are there exemptions for trade secrets or proprietary information?

Mr. Woo: That is a very good question. Under FracFocus, they provide the concentration. From the trade secret perspective, we work with the B.C. OGC. If a company does use a trade secret, we could ask them to submit it in a different format that will have the chemicals disclosed.

Mr. Tredger: Just so that I'm clear, when you say the concentration, it would be the amount of each chemical that goes down, not just the fact that it is going down the well?

Mr. Woo: Yes. Under FracFocus, they provide the concentration of each chemical.

Mr. Tredger: And why 30 days after? One of the concerns in the north is that it is a very sensitive area, and in terms of working conditions and for the sake of first responders mitigating impacts, would it not be better to have disclosure of this information before the operations begin so that we can do some baseline data and we can alert people who may have to deal with it as to what it is.

Mr. Woo: Another good question. We, along with the Sahtu Land and Water Board or the other northern boards —

the chemicals they may use will be disclosed up front. What we disclose on FracFocus is what the chemicals actually used are after the operation is finished.

Mr. Tredger: Again, the north is quite a sensitive area. We are a long ways from major centres. How do you assess the ability and cost to remediate after an event, be it a small spill or catastrophic event, and what do you have in place or put in place if a major event does take place? Has there been a way to mitigate the effects on an aquifer or river or wetlands in a responsible manner should an event occur?

Mr. Kabir: The company is requested to submit an emergency response plan. As part of their emergency response plan, they have to identify how they are going to manage if there is any spill.

Mr. Tredger: I guess my concern is that sometimes we are dealing with smaller companies, and if there is a major spill or event in the north or the Beaufort Sea or in an isolated area of the Sahtu, the costs would be increased proportionately. Is there a backup plan? How do you ensure that the company does have the resources to fully remediate an event?

Mr. Kabir: During the application process, they need to demonstrate that they have the financial capability to mitigate some of the risk you were talking about. If they don't demonstrate it, we don't approve.

Mr. Elias: Just to expand on the permafrost question given to you earlier, what mandatory requirements do you have in the Northwest Territories for regulations or directives for companies to follow that they have to adhere to when there's continuous permafrost before, during and after drilling?

Mr. Woo: As one of the things that Kabir mentioned during his presentation, they need to identify groundwater and permafrost and give us their plans for how they protect the permafrost and groundwater during the drilling. At the production phase under the *Canada Oil and Gas Operations Act*, we have a stage called a development plan before any operator can develop its field, including those fields that may have continuous permafrost. They need to demonstrate how they protect permafrost at the production phase.

Mr. Elias: Over in Norman Wells, they're drilling into the Canol Shale and that Canol Shale extends right over into Eagle Plains. The Eagle Plains depth of the Canol Shale is quite a bit deeper than it is over in Norman Wells. We're also dealing with a thermokarst subsurface geology. Over in the Yukon in Eagle Plains we are very close to that and to limestone.

Do you require your surface casing in the Northwest Territories to be below any identifiable drinking water? How do you define what is potable drinking water or drinking water? It's a two-part question.

Mr. Kabir: So, the current filing requirements require a company to identify groundwater — that is, freshwater and surface casing. One of the objectives of setting the surface casing is to protect the groundwater so that the surface casing is set below all reasonable freshwater zones.

Mr. Elias: How do I word this one? What's the distance that you regulate for how far the surface casing goes before drinking water? Is it 100 metres? Is it 200 metres? How far do you regulate the surface casing below groundwater?

Mr. Kabir: We will assess case-by-case depending on the geology and the position of the groundwater zone. If there is a good formation below the groundwater — that will depend on where the good formation is below the groundwater so that the casing depth can be set there.

Mr. Elias: No further questions.

Chair: We are going to start now with the questions from the public gallery. We are going to start with Ms. Moorcroft.

Ms. Moorcroft: I have a question from anonymous here.

The previous presenters from the Fort Nelson First Nation spoke about the lack of consultation. The question is:

What is the National Energy Board's position on the approval of applications for oil and gas developments in northeastern British Columbia on First Nation lands without First Nation consultation and permission?

Mr. Sprague: We have a very strong consultation program as the National Energy Board and we have filing requirements and expectations that companies are performing consultations, so our opinion would be that there should be good, solid, strong consultation with impacted parties where projects are being proposed.

It is in our filing requirements and you're going to hear this a lot in our applications, being quasi-judicial, where case-by-case application assessments — so the board members decide every case based on what is presented to them as to what is appropriate consultation. It is in the filing requirements to conduct adequate consultation, so it is a requirement for the application.

Mr. Silver: Thank you, Madam Chair. This question is from Jacqueline Vigneux.

Have you or your expert committee read the following document: *Brief Review of Threats to Groundwater Contamination from the Oil and Gas Industry's Methane Migration and Hydraulic Fracturing*?

Mr. Kabir: I have not.

Hon. Mr. Dixon: This is also from Jacqueline Vigneux from Whitehorse. Both Roland Priddle and Ziff Energy provide long-term forecasts for each of NEB's seven LNG approved applications. In your estimation, how reliable are these two consultants' documents and approval for Canada's national gas forecasts, given all the approvals and upcoming approvals for LNG and tar sands usage?

Mr. Sprague: Again, I'll refrain from sharing our opinion on the Priddle and Ziff reports and recommendations and what their thoughts and commentary might be. I can get it for you — I can't think of the name right now — but we do our own market and supply report that we prepare and publicize and put on our website for people to see what the NEB's projection of supply and demand markets are for Canada.

Mr. Tredger: This is from someone anonymous. Why are frack fluids disclosed after the fact instead of before?

Mr. Woo: What FracFocus discloses is 30 days afterward, but in my prior response, through the Sahtu Land and Water Board or the other northern land and water boards, they disclose what the operator may use and FracFocus actually discloses what they finally do use.

Mr. Elias: This is from Marguerite Roberts from Whitehorse. What responsibility does the National Energy Board accept for the environmental cleanup and health degradation, if any, of the projects approved by the National Energy Board that result in environmental catastrophes, i.e. severe health impacts?

Mr. Sprague: We regulate all the facilities and projects that are within the jurisdiction of the NEB on a life cycle approach. The jurisdiction responsibilities we have cover any accidents or malfunctions that occur during that life cycle. Every action — or every requirement and action we take in application assessment and compliance verification activities are all designed to prevent any substantial impacts to the environment. We do have emergency preparedness and response expectations and an assessment and we audit companies' programs around how they're going to be able to effectively mitigate any accidents that do happen. We do hold the companies accountable to have good management systems so that, when those — if those — emergency plans are ever needed, they're implemented effectively.

Chair: I have a question from Ms. Hanson. The regulatory regime you describe appears to be that of pre-devolution, i.e. for Northwest Territories, Nunavut. What role does the NEB play in Yukon where the federal government has transferred in 2003 responsibility for management and administration of land and resources to Yukon?

Mr. Sprague: You will notice on — or if you did notice on that slide that we had up there, the Yukon was not coloured yellow for the NEB's jurisdiction for responsibilities of regulating in the north. We do know that the Yukon's in the north, so I believe we have a memorandum of understanding with the Yukon government to conduct any regulatory expertise that may be required on a request basis. And I believe that's the only role we play in the Yukon.

Ms. Moorcroft: This question is from Don Roberts. Why were water boards in the Northwest Territories dismantled and who took over their responsibilities? Are there plans to dismantle the Yukon Water Board in a similar fashion?

Mr. Sprague: That's a really good question but its way beyond the scope of us as a National Energy Board panel here to discuss or to answer. I would ask the same question myself.

Mr. Silver: This question comes from Sandy Johnston. How is NEB's priority to ensure adequate domestic supply of natural gas being addressed in light of your recent approvals for the export of LNG that in total exceeds the current production of natural gas in Canada?

Mr. Sprague: Another difficult one. We came prepared to talk about fracking and drilling and our filing requirements for fracking. We have a department that looks after supply and demand and markets for Canada. I'll have to get the name for it, our supply/demand report that looks at the entire picture for Canada. I believe we produce it every two years and put it on our website for everybody to see exactly how the NEB is seeing that future of supply and demand for Canadian energy sources.

Hon. Mr. Dixon: I think this one you have perhaps answered already but perhaps you can build on it. From Rick Griffiths of Whitehorse: what is role of the NEB in Yukon and do you have the authority to override regulations drawn up by Yukon?

Mr. Sprague: I'm definitely not an expert to talk on the jurisdiction of the NEB to overrule anybody's regulations, so I'd be speaking way out of turn to even guess at the answer on that, but other than having a signed MOU to help out on a request-by-request basis on any regulatory matters, I don't believe the NEB has any role in the Yukon regulation.

Mr. Tredger: This question is from Don Roberts. What are the expectations with respect to the price of LNG in North America once exports commence to much higher-paying foreign markets?

Mr. Sprague: Another really good question and one we didn't really come up here prepared to answer and talk about — the supply and demand impacts and markets. Again, on the NEB website, there is information on how that is being viewed and what the current outlook is for a lot of those issues.

Mr. Elias: This question is from Gary Bemis from Whitehorse. What is the life expectancy of the biocides used in the fracking process — hours, days, years?

Mr. Kabir: There is no specific life cycle of the biocide. It's designed to prevent the degradation during the hydraulic fracturing and, to some extent, flowback period. Once the flowback is done, it's the formation fluid. Formation fluid doesn't require the biodegradation.

Chair: I have a question from Sandy Johnston. What role does the National Energy Board have with regard to ensuring that the GHG emissions of the combined projects it approves do not affect Canada's obligation to reduce GHG emissions by 17 percent from 2005 levels by 2020?

Mr. Sprague: In the environmental protection plans that we require to be prepared and submitted by the companies, one of the issues that is covered is cumulative effects and greenhouse gas emissions. We consider that in the technical review that we saw as part of the process in Mr. Kabir's presentation, so we do look at greenhouse gases and the plans to eliminate or minimize those as much as possible.

Ms. Moorcroft: Just to explain, the first two questions that I pulled out were identical to questions that have been read, so I'm now going to ask a question from Sandy Johnston. With FracFocus, are there any exclusions for proprietary concerns? Is there independent verification of data submitted by industry to FracFocus?

Mr. Woo: In some cases there will be some chemicals that will be proprietary, but in response to the prior question, we have been working with the B.C. Oil and Gas Commission which owns FracFocus.ca. We may request an operator to resubmit in a form that has all the chemicals disclosed without disclosing the recipe for the proprietary chemical.

The second part of your question again was —

Ms. Moorcroft: About independent verification.

Mr. Woo: The chemicals are generally provided to the operator by the service company. At this point, I am not clear on the independent verification part.

Mr. Silver: This question comes from Rick Griffiths. As a national regulator, do you oversee provincial/territorial regulations in defence of a national standard?

Mr. Sprague: We're always collaborating as much as we can, as you've seen with some of the practices that Alberta and B.C. have undertaken with FracFocus. I believe we try to keep a harmony and we're all looking at the best practices. I would be speaking above my pay grade to comment on whether we influence any of those provincial regulations with a national interest. It is beyond my ability to comment on that.

Hon. Mr. Dixon: This is an anonymous question. There are numerous studies beginning with the 2011 study by Howath and Ingraffea that are warning us that natural gas exploitation — particularly those related to fracking — are causing more fugitive methane emissions and thus further exacerbating global-warming impacts. Could you comment on these concerns? Would you agree that it would be wiser for the Yukon to impose a moratorium on fracking until the industry can absolutely prove that it is safe to both our climate, locally and globally, and our water resources before we even consider moving toward oil and gas?

Mr. Kabir: I'm not aware of this study. If anyone wants to —

Mr. Tredger: This question is from Sally Wright of Kluane Lake. Will the NEB review the cumulative impacts on a watershed-by-watershed basis or on a geological-basin-by-geological-basin basis?

Mr. Sprague: Again you're going to hear me say on a case-by-case basis. The expertise and the risks and the mitigations for each independent project that is put in front of the board will be reviewed on its merits and risks, and those decisions will be made by the panels that are reviewing each project that is in front of them.

Mr. Elias: This question is from Julie Frisch. Who is FracFocus? Who pays their bills and who employs them?

Mr. Woo: In the U.S., it was started by the Groundwater Protection Council and the Interstate Oil and Gas Compact Commission and it is covered off by them, and in Canada it is B.C. OGC, but whoever else joins, like the NEB, they would have to sign a commercial agreement and so it partly is the regulators — so in Canada, it would be the regulators.

Chair: I have a question from anonymous. Where is the regulation about greenhouse gases? Perhaps that is, are there regulations about greenhouse gases?

Mr. Sprague: So again, we came up to talk about fracking and drilling and the filing requirements for that. The environmental protection plan and the management system approach — the performance-based regulation asked for an environmental protection plan to be prepared and submitted by the company, identifying all the risks and impacts to the environment. Within that will be greenhouse gas emissions and the company's plans to mitigate those impacts.

Ms. Moorcroft: Question from Sally Wright. Why did the NEB allow a vertical fracking well by MGM in the Sahtu in the Northwest Territories without an environmental review?

Mr. Sprague: I'm not aware of the exact circumstances that are being described there and I would not want to discuss a board member panel decision that I wasn't privy to — and I pass on that question right now.

Mr. Silver: This question is from Sandy Johnston. How will the massive export of LNG from North America affect the price of LNG and natural gas in North America?

Mr. Sprague: Another really good question on supply, demand and prices. Again, we do release a report at the NEB that discusses exactly those impacts and the forecasts of price and supply/demand. It is on our website, and now that it's the fourth or fifth question, I'll make sure I send that link up here when I get back to the office.

Hon. Mr. Dixon: This one has perhaps been covered already, but I'll ask anyway. It's from Marguerite Roberts. What role does the NEB have with respect to ensuring and monitoring the cumulative GHG emissions of the combined projects it approves do not affect Canada's obligation to reduce GHG emissions by 17 percent from the 2005 level by 2020? Please explain how we are on track to meet these given projects that have been approved and increases expected from the development of shale gas and tar sands.

Mr. Sprague: Another really good question on greenhouse gas emissions and again, our portion of it and the regulatory regime that we use does ask for an environmental protection plan that does identify all the risks and all the impacts to the environment that that project would have. If it has greenhouse gas emissions, we expect the company to describe exactly what they are going to do about those greenhouse gas emissions to minimize them as far as they possibly can. I did not come prepared to talk about how that's impacting Canada's commitment as a whole.

Mr. Tredger: I have another question on the price of LNGs, so I will go on to a second question, as you have already answered that. Sally Wright has asked a question — I note that the NEB regulates mostly in the north. What are the regulations associated with permafrost?

Mr. Kabir: In our drilling and production regulations, it requires surface casing design to be set so that the permafrost and ground are protected.

Mr. Elias: This is another question from Sally Wright from Kluane Lake. Does the National Energy Board keep track of the total amount of water that has been poisoned and lost to living beings in perpetuity by the oil and gas industry? When will the National Energy Board start charging the oil industry for this loss?

Mr. Sprague: The answer to that one is a difficult one in the way the question was posed. I would like to say that, as part of that environmental protection plan we discussed about greenhouse gas emissions, any environmental impact — whether it's impact to water, impact to flora and fauna — it's all addressed in the impact assessment by the company that's proposing the application to the NEB.

On a case-by-case example or application, we assess those impacts and the company's mitigation plans to minimize them. If we can't minimize them to an acceptable standard or if the company can't minimize them to an acceptable standard, the project would not be approved.

Chair: I have a question from Sally Wright. What is the CO_2 equivalent that the NEB uses for methane? Does the NEB recognize human-caused climate change?

Mr. Sprague: Another good one. It's hard to speak to these ones that say what does the NEB view the impact of it.

I would say that based on the environmental protection plans that we asked to be submitted and what companies are identifying as environmental impacts, greenhouse gas emissions and energy projects have impacts on greenhouse gas emissions. They do have greenhouse gas emissions and that has to be assessed and has to be mitigated to an acceptable degree. We do request that companies identify every impact that a proposed project would have on the environment.

Chair: The last question goes to Ms. Moorcroft.

Ms. Moorcroft: Thank you. A question from Sandy Johnston: What baseline water quality data for surface and groundwater do you require to be collected prior to drilling?

Mr. Woo: As part of the slides that Kabir had up, a lot of the water resources in the north, especially in the central Mackenzie — that's the jurisdiction of their various land and water boards — we also work with them. This type of drilling activity is new and we do have to establish some baseline of those water wells. It's a new activity in the central Mackenzie, so we are initiating with the land and water boards groundwater monitoring to establish those baselines.

Chair: Thank you. Now that we are out of time for questions, I want to thank the NEB for participating in our presentations. I want to thank the visitors for participating in our questions. The Committee will review those remaining questions and see if we can't get some answers for them.

These proceedings are now adjourned. Thank you very much.

The Committee adjourned at 5:02 p.m.