Melbourne – Schlumberger

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Melbourne

Speakers: Paul McDougall, Joe Lima and Daniel Kalinin

Hon. Justice Rachel Pepper: Good morning. I'd like to commence by acknowledging the traditional owners of the land upon which we meet today. I pay my respects to their elders past, present and future. Thank you.

Gentlemen, if you could please introduce yourselves and explain who you're here representing today, thank you.

Paul McDougall: So I'll start. My name is Paul McDougall. I'm representing the Schlumberger Australia Land Business.

Hon. Justice Rachel Pepper: Thank you.

Joe Lima: Good morning. My name is Joe Lima. I'm the Director for Environmental sustainability for Schlumberger, it's a global position and I'm based out of the US.

Hon. Justice Rachel Pepper: Thank you.

Daniel Kalinin: Morning. My name is Daniel Kalinin. I'm representing Schlumberger Australia. I'm in the field of hydraulic fracturing stimulation, based in Brisbane.

Hon. Justice Rachel Pepper: Thank you very much. Whenever you're ready. Thank you.

Paul McDougall: Okay, again, thank you to the panel for availing of this opportunity. We were a bit late getting our corporate permission to do so, but again thank you. Again, I'd like to acknowledge the traditional owners of the land where we are, and also the basins where we operate in Australia and the elders past, present and future. I'd also like to thank the panel for the body of work that you've done in the interim report that has been published. We're very appreciative of that work and the torrid schedule that your community engagement of your available population of the NT of getting that communicating, so I appreciate that very much, and also thanks to Joe who has travelled a long way to be here today and I'll hand it over to Joe to take it from here.

Joe Lima: Great. If you don't mind, I would like to share some slides with you to give you a little bit of my background, but also our experience with the unconventionals.

Hon. Justice Rachel Pepper: Thank you.

Paul McDougall: Just one second while we get the presentation happening.

Joe Lima: You can tell we're experts on oil and gas but not PowerPoint.

Hon. Justice Rachel Pepper: It's giving me great confidence gentlemen.

Joe Lima: Great. I somewhat struggle with what the title of this presentation, but just decided to Unconventional Reservoir Development since that is I think what you're trying to understand. Just a little bit about Schlumberger. Schlumberger is the world's largest oil field service company. We employ around 100,000 people and we're working in over 85 countries worldwide. From a technology perspective, what we provide to our customers, we like to refer to it as a core to port hole. Core to pipeline perspective. Basically the things that you do to extract oil and gas from the ground and bring it up to the surface. That being said, essentially all places where oil and gas is being developed around the world in one way or another Schlumberger is interactive with those reservoirs. We have facilities again in 85 different countries. We have employee nationalities totaling about 140. Our company is 90 years old, we were founded in 1927. What you see on the bar graph here is basically the history of how Schlumberger has grown to be where we are today. We started out as a wire line company getting measurements of the reservoir rock, and we've progressed from there. One of the major companies that we acquired was in the 1960's, Dowell, which is where our pressure pumping experience, hydraulic fracturing, cementing and so on came from.

I draw your attention to the centre of the screen there at the graphic in the middle. We believe in reinvesting into research and engineering. Since 2011, every year we have invested over one billion US in research and engineering. This is technologies to further the things that we're delivering to our customers to help them extract oil and gas out of the ground. Throughout my presentation, I'll talk to you a little bit about the application of these technologies in an effort to more efficiently and safely help our customers produce hydrocarbons. So before I get too far into that, I'd like to give you a little bit about my experience, my personal experience. I'm a petroleum engineer. I've worked for Schlumberger for nearly 30 years now in various roles. Engineering roles, management roles and so on. Prior to the role I have today, I worked on Schlumberger's green chemistry for fracturing fluids. I also am the architect behind our chemical disclosure process, which is ultimately been adopted by frack focus as being the standardised process.

That being said, I'm going to go ahead and delve into the unconventional somewhat. I don't know if you're familiar with the concept of a resource triangle, but the graphic you see on the screen basically is saying that the high quality rock where oil and gas would flow naturally and so on is small in quantity. You look at the tip of the pyramid and its base across the bottom of the triangle is fairly small. As you move down into poorer and poorer quality rock, we end up with much more of that available to go out and produce hydrocarbons from. It is obviously the gas bearing shales and oil bearing shales where today most of the focus is on the unconventionals. The definition between conventionals and unconventionals essentially is that you have to stimulate the rock in order to make it produce. But as you move down the triangle, you're F & D, or finding and development costs increase. You have to put more technology in order to extract the hydrocarbons out of it. So it is something that has become more of a challenge to work in those types of environments.

Going back quite some time, looking at the evolution of the reservoir rock, obviously we're extracting hydrocarbons from organic matter that's been buried in the earth. Typically, geologists and geophysicists would be looking for structural traps, places where oil and gas would accumulate. They would end up with some degree impermeable barrier where the oil and gas would accumulate. They would identify those, and then they would drill to that. This would be closer to the top of that resource triangle. This is before hydraulic fracturing was really being deployed. In hydraulic fracturing, even though it's well documented that it's decades old, realistically hydraulic fracturing has been implied, in large scale, to the late 1980's and early 1990's. It is in that time that our customers were drilling into tighter and tighter rock. Mostly that was sandstone. The wells that were being drilled were typically vertical wells. As you are moving down into this tighter rock, you needed to have more wells in quantity to achieve the economies of scale.

Then come about 12, 15 years ago, the combination of horizontal drilling and hydraulic fracturing, but multi-stage hydraulic fracturing. In other words, breaking a horizontal well bore into smaller sections and stimulating it in a discreet manner. That has ultimately allowed us to economically produce from that very tight rock that's at the bottom of that triangle, the shales. I'd like to emphasise that it's a combination of existing technologies. Directional drilling's been around for quite some time, hydraulic fracturing's been around for quite some time, the combination of these two things has enabled it to happen. There were some technologies that had to be filled in, so how do you effectively and efficiently break up a horizontal well bore in order to be able to stimulate it? It's that type of development that allowed us to work in the unconventionals.

Why does hydraulic fracturing work? Why does hydraulic fracturing in combination with horizontals work? It's all about surface area. In this case, I have three different examples to show. On the upper left is a vertical well that's drilled through a 60 metre high reservoir rock. Without stimulating that, the surface area that you've come in contact with before the casing's put in place is about 30 square metres. If you take that exact same scenario and you put hydraulic fracturing, frack with two propped what we call frack wings, going off in either direction, to a length of about 60 metres, you end up with about 15,000 square metres worth of surface area. If you take that exact same rock and you put a horizontal well through it and you were to place 15 hydraulic fracturing stimulations on it, all the same length is as the one that's on the upper right hand corner, you now end up with an order magnitude, more surface area. In this case, calculating out somewhere in excess of 200 thousand square metres. It is about surface area, this is what makes these economic, what makes them produce.

Unfortunately, mother nature hasn't been kind to us. From one place to another, what would be classified as a shale, or an unconventional formation, is not the same. They vary in mechanical properties in mineralogy and so on. There may be quote unquote "technically shales," and even vertically within the same horizon you end up with variability because, as you remember from one of the slides I showed earlier, the material that we're producing from has been deposited over millions of years and they've changed in the quality as well. Another thing that buries is the height. Some of the ones that you see listed on the screen here, namely the Marcellus in the Eagleford and the Barnett are three of the more successful shale plays that we see in the US today. They are much smaller in scale than some of the others that we see elsewhere in the world. It begs the question, why is it so successful in the US and in Canada and we don't see it elsewhere? The simple reason why is because it's the information that we have.

The US has, and Canada as well, has the benefit of having a long history of drilling. Not necessarily into these formations, but in some cases formations that are deeper. There's a wealth of information, existing wells, and so on where we can tap into that data and basically build reservoir models. It's that experience that we have based off of previous drilling experiences that we can then tap into building reservoir models that allow us to be more successful. But again, what I'd like you to take from this slide is that variability in the reservoir rock is considerable.

Now I'd like to talk a little bit about how we work through the philosophy of going from expiration to appraisal to ultimately into a development phase. If you take this example, essentially you take seismic data as is shown on the right hand side of the screen, and you interpret that information to say, "Okay, here's the structure that is of interest and I'm going to do some further exploration into that." And then you map what's on the left side of the screen. The aerial extent of potential play. In this case, we're showing two existing wells, which may have some information telling you that a play of interest exists at about this depth and you can correlate this back to the seismic information. This is where the model starts to build. We understand that there's something that may be of geologic interest here, and its potentially hydrocarbon bearing.

The next thing we do is we start looking at the properties that are driving reservoir quality. Can the reservoir physically deliver the hydrocarbons to a well bore? We're looking at things such as the clay content, core pressure, the stresses in the formation, Young's modulus, Poisson's ratio, natural fractures and so on. But we look at all this information including the mineralogy and start to develop a map saying here is the high quality reservoir rock.

The next thing we do is just start looking at the completion quality. We start to ask ourselves can that well physically be stimulated? Can you hydraulically fracture it effectively enough to make it produce? In this case, we've highlighted that there are some faults that are going through this that would make it difficult in some places to hydraulically frack that portion of the well. Ultimately, we end up with a map that says here's the sweet spot. Even though we started out with this understanding that the aerial extent of the formation technically may be something that is the highest quality in order for us to complete, is a subset of that. It's a philosophy that I'd like to say that in some instances the best well is one that you don't drill at all.

Now once you start to build this, you can then develop your completion model. What you see on the screen here is a graphic that comes from one of our hydraulic fracturing models. It's showing an actual stimulation of what a hydraulic fracture would look like for this particular reservoir. You can see how it is extending out from the blue section, which is the vertical well. This case it is a vertical well. We haven't drilled a horizontal yet. We're really trying to calibrate and gather information about rock properties and how can the well physically be stimulated, or this formation be physically stimulated.

What you see to the right of that is some mineralogy information, core pressure information and so on that we've derived from various logs that were run into the well. The next piece over is a production log from that specific well, so its saying this is where we physically are producing once we've stimulated it. Then we can go back and we combine that with stress models to be able to go and say this is what fractured geometry looks like. This allows us to essentially continue to calibrate the model and become better at understanding what the extent of a hydraulic frack will look like, both from a vertical perspective and from a horizontal perspective.

At that point, and you see the same simulation on the right hand side but it's looking at a different perspective. We can then start planning where you're going to land wells. What you see, the green line running through the black portion of the screen is the horizontal well that's adjacent to that vertical well. This doesn't happen on every single well you stimulate, you don't always drill a vertical well adjacent to it, but it's that mechanical information that you get from the modelling that allows you then to transpose that for the horizontal well bore. Essentially, at that point, we can go in, we can model what the stimulations will look like throughout that environment. This helps us with things such as how we're going to break up the well bores, the philosophy on how you will stimulate the types of proppings that you'll use, the fracturing fluids and so on. What are the most effective in order to properly stimulate that reservoir rock. It's that model that is applied from one horizontal well to the next horizontal well.

Now let's talk a little bit about the places that are happening in the US. You can envision that this map would extend obviously into Canada as well. There are a sizable number of unconventional reservoirs in Canada that are economically viable. But, I'm just going to concentrate a little bit about the US experience on this. You see in orange, the gas plays and in blue the oil plays, so liquid-rich plays that are existing throughout the US. Many of these plays had a life previous to working in the current horizons that they're in today. Some of the newer environments are in the Northeast portion of the US, namely the Marcellus and the Utica shale, in Pennsylvania and Ohio, respectively. It is in those places where the oil and gas industry was largely absent for many decades after the initial shallower plays that were being completed decades ago. Now there's quite a bit of development that's going on in those environments.

We see, in the US, a lot of challenges as far as the different stakeholders that we have to work with. In some places you're working in federal lands where you might have some endangered species or potentially endangered species that people are concerned with. How you plan the development in that field becomes critically important. In other places, you're working directly adjacent to communities. Namely north of the city of Denver in Colorado, there's a large oil and gas development going on up there. I'll talk a little bit about that here in a moment. As I mentioned earlier, the US is not the only place where there are potential unconventional reservoirs to be developed. We find them all over the world. But again, the level of information that's physically there to allow that development to occur at the same level as what you see in the US does not exist.

Let's talk a little bit here about global stakeholders. Undoubtedly you've heard the term social licence to operate. We like to look at this as more of a social contract. A licence implies that it's one entity that has the permission to go off and do something and they're the ones who are ultimately in charge of what the development looks like. We like to look at this as being a partnership amongst many different stakeholders. On the graphic at the top of the screen, you have the communities, which we work in and amongst. And their concern was primarily safety, the financial stability, what is this going to do to my community as far as the strain that's going to add to it? In some instances, they don't benefit directly from the oil and gas production, so their direct benefit from it is implied.

You have then, going clockwise around this, you have the consumer. They're looking for, obviously, resources at the lowest possible price. Ideally speaking it's not happening in their backyard. It’s coming from somewhere else. Continuing on around, the environmentalists are looking for how do you ensure that the air is clean? The water is clean? Can we move toward renewable energies? At the bottom of the screen, you have the oil and gas industry, obviously trying to make a profit from drilling and completing and producing hydrocarbons. Today they're looking at how they can do that with more environmental sensitivity.

The next group is the regulators and the legislators. The question becomes how can we produce this, do it in an affordable manner, but also make sure that we're protecting all the various entities including the environment? Last but not least, it's the resource owners themselves. In the US you have a mix between privately held and federally held resources, and in some instances you may have folks who own the minerals for the hydrocarbons and a completely different entity that has the water rights. So those things all play into the complexity. In many instances, they're wanting to be able to produce those. Whether it's the hydrocarbons or the water, they're wanting to be able to monetize that. All of them have an equal say what the development looks like, ideally speaking.

One of the things that we hear quite frequently is that the industry is not well regulated. What this graphic is intended to demonstrate, or a snapshot of some of the regulations that exist in oil and gas development in North America. It's everything from well spacing to well abandonment, site reclamation, the setbacks on the surface from various entities, air quality and emissions. Even things like in some places around in due seismicity, and of course, as you're probably well aware, North America has ... Most jurisdictions has requirements around chemical disclosure for hydraulic fracturing. This is just a snapshot. This is not inclusive of all the regulations that we run into in North America. This is just to give you an idea of some of the ones that commonly do exist.

We started talking about the basin-based type of regulation. As an example, I'd like to talk a little bit about Colorado. Colorado has a long history with oil and gas development. It started out early on in Front Range Colorado, North of Denver on some shallower sandstones. What you see, the blue line on this graphic is the drilling rig count over time. This is how many rigs are running each month over time. The yellow dots represent key pieces of regulation that were put in place to manage that type of activity. The shaded areas represent different geographic portions of Colorado, so within the same jurisdiction, different geographic environments that we were working in over time. The first section is north of Denver. These were mostly vertical wells. You can see the rig activity was, relatively speaking, low. You see the regulations when they were coming into place.

Then, in the early 2000's, the gas plays in the Western Slope of Colorado started taking off. This is a play called Piceance Basin. Most of these were vertical wells, and you can see how the rig activities spiked at the time in excess of 100 rigs running per month. You see that the regulations were coming into place. Then, when we get into 2010, activity shifted to the oil bearing plays on Front Range Colorado. Back to Front Range, except now we're dealing with mostly horizontal wells in a completely different horizon than the original wells that were drilled out there. I've highlighted out some of the regulations that were put in place to address that type of activity. Things such as well bore spacing. GWA stands for Greater Wattenburg. Fracture disclosure, off-set well monitoring, this is from an existing well that may be in a completely different horizon, being able to see whether or not you're physically hydraulically fracturing into that. Spill reporting was updated, wildlife mapping, fugitive methane, water sampling and so on. The point about this is that the regulations are continuing to shift. They shift according to the types of horizons that are being developed in a geographic area, but also because of the change in activity levels and spacing of wells and so on, and so on.

But those things are driving, ultimately, what the regulations look like. The regulations in Colorado, while they may mirror other jurisdictions in the US, they have some unique components to it. And others would have some unique components that apply specifically. In other words there isn't a standard set of regulations, here you go, this is what you do. They're based off of activity and the types of horizons you're working in. Sticking in Front Range Colorado in this map, you see in the bottom of this screen the City of Denver. The red dots represent wells that exist north of the city of Denver. There's about 18,000 some odd wells there. Again, some of them are very old wells. When I say old, they might be 25, 30-year-old wells. Some of them are, relatively speaking, new over the last few years. You'll note that there is a hole on the upper portion of this map.

That hole is the city of Greeley, Colorado. That's within the city limits of the city itself where you have a fairly high density of folks living in the middle of an oil and gas play. That has largely been undeveloped and in this scenario, operators are looking at using multi-well pads and horizontal drilling to essentially drill underneath the city and be able to produce staying away from basically the potential of being offset to communities, to homes, to businesses, to schools and so on. They're using modern technology, essentially, to stay out of a certain environment.

Shifting to the Western Slope of Colorado, this is a picture of the Piceance Basin. This is the Piceance Basin after quite a bit of development. Obviously, this is a completely different type of an environment. Unlike the stuff that's happening today in the front range part of Colorado, this is very rural. Beautiful landscape and so on, like we see in many parts of the world. You can make out that there's a road coming up through that creek valley and you'll see a couple of locations that are apparent there. The vertical relief on this from the creek bottom to the top of the Mesa's is somewhere around 500 metres and change. Building roads up to the top of the Mesa's doesn't make a whole lot of sense. This play, when it was really active, was in the beginning of last decade, early 2000's type of timeframe. This is an aerial map of that same play. Looking at this creek valley, you can see where the creek comes in from basically three different directions. It was on the right fork of the screen where that image that I showed you previously was taken.

Looking back down toward the middle of the screen. You can make out, if you look carefully, in that valley section some beige areas, which represent the well sites, the pads. What does this thing look like below the surface? Same perspective from those pads, basically you're drilling off into different bottom hole locations. This horizon is a sand stone. It's a stack pay. But still, the philosophy of onshore pad-style drilling was born here, taking essentially the philosophy what you do in an offshore environment and import it into an onshore environment. What this allows you to do, is basically not develop on top of the mesa's and work around these environments and work from where the drilling might be easier down at the bottom, but also access to the land was much easier.

This is an image from one of the locations, or a cartoon from one of the locations that shows the different well bores from a single location going to different bottom hole locations. You can see that basically the wells are drilled directionally from a common pad, and then turned back to the vertical to intersect the target horizon. In order to make this happen, the industry had to become somewhat innovative in developing technologies. One of the things was the ability, since you had multiple wells in the same location, the ability to have the drilling rig move on its own. So, after you're finished drilling a well, the rig could literally lift itself up and move a few feet, set itself back down and start drilling again. This is where that type of technology was ultimately derived from.

At the same time, when you're drilling wells, you want to start to recoup that investment as soon as possible. Another way that the industry changed was to allow hydraulic fracturing to occur at the same time that you're drilling directly on the same location. This image, obviously taken in the winter time in Colorado, is a hydraulic fracturing crew on location with a drilling rig. What's difficult to make out on this image are some of the details that occur in order to make this happen, which included a blast wall that exists below the rig to prevent that if there was ever an accident on the hydraulic fracturing side that the rig would be protected from it. On this location as well, there are wells that are physically producing at the same time. Essentially you end up having what we call simultaneous operations occurring on location. But this required management of change, it required the companies that are doing these types of things to develop new processes and procedures to work in that unique type of an environment.

Finally, this is what the end result looks like. In this particular case, and this is an extreme, is 52 wells on a three-acre location, all going to different bottom hole locations. There are some inherent benefits of doing this as well from a production perspective, that all the production is being gathered to one location and from there it's being managed as opposed to being individual locations and then you're collecting the gas or the water that's being produced and having to take it to another location.

Not I'd like to talk a little bit about the learning curve. This is on the drilling perspective. We see this repeated in every basin that we work in. The first well that's drilled is the least efficient well. It’s the one that's drilled the slowest, there may be things such as data that you have to collect, and so you're drilling much more slowly. You're also looking at the accommodations of drilling fluids and bits and the right equipment in order to become very efficient at drilling. What this graphic shows, the blue line is the days from spud, which is the starting of drilling, to rig release. So, when the drilling rig is done. Hydraulic fracturing hasn't occurred yet. We're looking specifically at that portion of the operation, which is drilling the well.

The very first well that was drilled in this particular horizon, which is in the beginning of 2010, the bars represent each the number of wells that were drilled each and every month. That very first well took in excess of three weeks. Today, they're drilling the same wells in less than one week. That learning curve was significant. We see this again in all plays.

One of the key advantages of climbing up this learning curve, the experience that's under your belt. But, also the fact that when you're more efficient, ultimately it means that there's less amount of time that you're impacting surface entities. Stakeholders that either live adjacent to wells or maybe it's wildlife in the area and so on. In other words, you get the wells drilled and completed quicker.

The next piece is the well integrity. Obviously the most important component of a well is the construction and the cementing of that well and preventing contamination into aquafers and so on and so on. Cementing of wells is not like building a sidewalk. The technologies that are employed are different. You may have the same basic product, Portland cement, but what we're doing is creating a barrier to prevent fluids and hydrocarbons and so on from migrating to other horizons. The technologies that are derived here are pretty significant and impressive. We have today technologies that allow us the cement system after it's been set to essentially re-heal when it comes in contact with hydrocarbons. It senses hydrocarbons and it can fix itself and shut itself off. We have technologies that allow us to work in places where you have corrosive fluids. We have technologies, which allow us to work where you're going to have repeated temperature changes and stresses that are associated with hydraulic fracturing. The engineering of those technologies designed depends upon the environment that you're working in and what you plan ultimately to do to that well.

In addition to the physical cementing technologies, you also have things on how you design the cement jobs. We utilise software to basically model the cementing. One of the critical components of cementing is the removal of the drilling fluids. Also, making sure that the casing that is put in the well is properly centralised. So, when you're displacing drilling fluids out of the well bore, the flow on the annualist will allow essentially the washing of the drilling fluid back out and provide a better area for cement to bond with both the formation and the casing. But it's that type of knowledge, the deviation of the wells and so on. Do I have any losses that may occur in the formations? It's those things that drive the cement design. You can get to a point where you understand that in a particular field I'm dealing with this temperature range, I'm dealing with this type of corrosive fluids and so on. You get into the generalised design of what you're planning on doing. Then, on each well you will go and run a specific lab test to determine that the cement is going to perform correctly, will it mix correctly and so on. We collect samples after it's been blended. The actual sample that's going out to location, and then it's tested to make sure that it's going to go and to perform correctly.

Last but not least, the equipment that we use and the expertise that our folks have to allow the cementing process to occur. On location, the amount of energy that's put into mixing the cement is critical. The equipment is specifically designed to allow us to mix cement on the fly and be able to get to the right density and to be able to have the cement perform in the same way that the lab results show that it was going to perform.

So let's shift gear and talk a little bit about water. This is a recently updated table showing water per well for various US basins. You can see it does vary. We have some plays like the Haynesville, which use a considerable amount of water. And also what I'm showing on there is the second column from the right is the amount of water that's recycled on a per-well basis. This varies from play to play.

We see in the Northeast portion of the US, Marcellus and Utica, the highest level of water recycling. We don't see it in other places. In some instances, it's because you either don't have a lot of water available to recycle, to reuse, or you're getting water from somewhere else. Maybe from a land owner, a rancher who is providing you water. That's just to get you an idea of what we're talking about on an average basis, how much water is utilised. One of the key things that we saw as an opportunity, because we don't always have flow back water from previously fracked wells to allow us to stimulate the next well, is could we use the produced water that's coming from a given field to act as our source?

As I mentioned to you before about the money that we spend on research and engineering, a group based out of the US, which is what we call our client support lab, decided to take this project on themselves. It fell out of the normal research and engineering processing we had within Schlumberger. They were trying to tackle the idea of can you frack with produced water? Their goal was to develop a technology that allowed you to use produced water without treating it. You can envision that when you treat water, and you're trying to get the salts and other things that are in out, you're creating a residual waste stream that ultimately has to then be disposed of at some sort of hazardous waste facility.

The goal was can we just use produced water the way it is? They developed a technology that allowed us to work, and you can see for this example here at the top of the screen, this is the salts that we had in this particular sample. You go from the water that's on the right which is orange in colour because of the iron content, to basically the fluid that's on the right hand side that has some viscosity and allows the proper transportation of propping in the ground. We were able to achieve the properties that we want and being able to use 100% produced water without having to do anything with it. So we thought this was great, and a lot of folks are going to be wanting to use this.

Unfortunately, going back to the regulations what we found out was that the regulations that had already existed in many jurisdictions throughout the US do not allow the accumulation of produced water. Produced water is treated as an oil field waste and has to be disposed of expeditiously. Even though the technology exists, the regulation did not reflect the ability that technology was continuing to change. That's something that today the regulators understand, and they're actively working on how to achieve that balance where somebody is not just accumulating produced water, not disposing of it but that you're going to be using it for that next phase.

On a related note, that type of philosophy allows us to do things like reduce emissions. I've taken the typical amount of water that is used in a US shale and I said, "Okay, if you're going to have to truck all that water to a location plus the prop in and everything else, how much equipment are we talking about? How many truckloads of water do you require? If you have existing production already within a play and you're having to get that production off and send it to some underground injection control or other way of disposing of it, you have trucks going in exact opposite direction and carrying things off location.

Technology has continued to evolve from where it stood, where that was the way you would do it to where today you can go out there and use various technologies to reduce the water requirements number one. But then number two, be able to use water that already exists within the basin to stimulate the wells. The right hand side of the screen then shows what that would look like. Because of that simple thing of being able to plan and how you use equipment and water that exists within a play and so on, that allows you in this case as an example, to reduce truck traffic by over half and to reduce the corresponding emissions significantly because you don't have all that truck traffic in the field.

Another practise that's happened commonly in large-scale development in the US today is that where you can, you'll develop some sort of water system within the play that allows water to be piped to locations. So, instead of having to truck it, you can move it across the surface in pipes to get to the location which further reduces the emissions. So, by using those technologies and those types of philosophies, you're able to take the emissions significantly down from where you would have been if you did absolutely nothing from a logistics perspective.

Let's talk a little bit about chemical disclosure. Hydraulic factoring chemical disclosure started in the state of Wyoming in the US in 2010. That was the very first jurisdiction to have a regulation requiring such. At about the same time, the oil and gas industry was working with the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission to develop a chemical disclosure registry, which today you probably know as FracFocus. That process started in the beginning of 2011. It was voluntary at first, so industry was essentially voluntarily, no jurisdiction was requiring it yet, disclosing to this database. It was later in the year that we started seeing the first of the jurisdictions that were requiring disclosure and they were basically pointing to FracFocus. Today, FracFocus covers essentially all the jurisdictions where we're fracking.

The shaded area of this graph shows the percentage of the global fracturing market that is under chemical disclosure requirements. Essentially, anywhere that we're hydraulically fracturing globally today is under some sort of disclosure requirement. Again, some of these pre-dated FracFocus and as such they don't reflect it. They don't reflect the requirements that are in FracFocus. Most of the operators in my experience that are working where there are requirements to disclose are also applying those same disclosure standards to jurisdictions where they're not required to do so. You will note that there's a couple of places there that are outside of the US, so in the beginning of 2012, British Columbia, Canada became the first province to require it. In mid-year 2012 Western Australia required chemical disclosure, but not only for hydraulic fracturing but also for drilling fluids and cementing as well.

Today, FracFocus allows two different options for disclosure. The process that we use is what we call a system style disclosure. Essentially we can disclose 100% with little to no reference for proprietary chemistry because we decouple the chemical constituents from their parent products, so in other words, if you have something that has a sort of factor or breaker and other products in it, and those individual products may be made up of different chemical constituents, by going out there and saying everything that went through the well head and decoupling it from the parent products, it makes it very difficult for somebody to go out there and reverse engineer. Now if you look at when chemical disclosure first was required in the US, we've been applying the same process since 2010, and that process to date we have not found a single instance where somebody has gone out and reverse engineered what we've disclosed.

Last slide and I'm going to turn it over to Paul. This is the transition to Northern Territory. In 2011, we had a customer that was proposing to do some work in Northern Territory. They asked us for a chemical disclosure. We happily provided them a chemical disclosure, full disclosure so they could do their planning. This is again, without a requirement for disclosure to happen. The philosophy is simply that if we can disclose that fluid in a jurisdiction requires it, we can sure disclose it in a jurisdiction that doesn't require it. We supply that to our customers so they could then do their planning. With that, I'll go ahead and turn it over to Paul.

Paul McDougall: Thank you very much.

Hon. Justice Rachel Pepper: About 10 minutes left gentlemen.

Paul McDougall: No problem. I'll be very brief here.

Speaker 1: Might be even briefer.

Paul McDougall: Get this happening again.

Changing gears completely from Joe's experience in North America and Colorado, in particular. I'd just like to briefly run through Schlumberger's experience in the Northern Territory. As you know, we're a service provider. We break our business up into different pieces. We have something called Schlumberger Land Rigs, formerly known as Saxon, and we also provide services such as the cementing, fracturing, wiLine and other elements to the group that happens in the Northern Territory. The Northern Territory campaign is a very significant logistics exercise. Getting all the people and equipment to the field location and we did this by charter flight in and out of Daily Waters, Elliott, ex Darwin, weekly crew changes, ad hoc drive in and drive out ex Darwin for VIP visits or specialists visits and buses.

The rig activity was typically 50 person for the drilling project. Services in frack and other was an additional 70 people that were mobilised and we had no HSC or environmental incidents for the duration of the campaign. Just to give you a bit of a breakdown of the input into the local workforce and economy. The local supply spends in 2015 is just over $240k and in 2016 was just under half a million. The key suppliers, local suppliers was in Katherine. Engineering services, recycling services, lots of accommodation at the Larimer Hotel, the famous Pink Panther and at the Daly Waters highway in, Indigenous Beverages Australia and the Northern Territory Government and Veolia Environmental Services out of Katherine. This is just for a small, limited campaign. A significant spend that gets contributed to the local economy.

An aerial photograph of what our drilling operation looked like with Rig 185 on the Amangie campaign. You can see that the ponds in the background there for the conventional and under balanced drilling. This is what we would regard as a relatively compact footprint. This is not what a development footprint would look like. This is the exploration phase. The small equipment and associated services required. You get an idea of the impact. Approximately 200 by 100 metre footprint. Something that was very meaningful for the team on site was organised by Origin with the local traditional owners was a Welcome to Country ceremony. If you talk to anyone involved in this campaign, this is something they will remember very, very distinctly. As a company, I'd just like to highlight some of the things that we are doing in Australia in terms of engaging with the traditional owners.

A reconciliation action plan has been conditionally endorsed as of April of this year. We're working with the Clontarf Aboriginal College, University in Western Australia. We're providing internships, visits for students to our facilities. We do defensive driving training and practicing for interviews interfacing with the corporate world. Closer to home for me in Roma Technical College in Queensland, we've had a couple of interns of indigenous students in our Roma base in the Wild Line facility in Roma. We have apprenticeships. There's one ongoing now with a mechanical apprentice who's working in the hydraulic maintenance of our tools, and the local community has been providing cultural awareness sessions. About 14% of our local spend, this is with local suppliers, is going to indigenous suppliers. We started this initiative in 2016, and we've been assisting local suppliers with the onboarding process with a big company like Schlumberger. How to navigate our procurement processes and be part of our supply chain.

Something I just did myself recently. I'm on the executive committee for the Cooper Eromanga Basin Aboriginal community and we did an on-site session at Lake Penina just off the Birdsville crack. We held the annual conference there. I brought some of Schlumberger's management, my family, and we got to interface with the traditional owners including the dairy people and understand their connection to the land and how they can participate in our business. We anticipate doing much more of this in the Northern Territory.

Just another couple of photos. Now we're moving onto what the frack lease looked like during the drilling phase with a rig on site. This is our people on site on Rig 185. Something we did with the regulator and the NT Government was that we created a model so that we could illustrate to the regulator there what the cementing process is like, what the casing design looked like so he could help educate his employees and workforce as to what we're actually doing. This was constructed by the Schlumberger Land Rigs Team in order to foster understanding of what we're actually doing and how this regulation applies to us.

Moving on to the frack side. Again, we treat that as a distinct operation. The rig had demobilised. Here's a photograph showing what the frack spread looked like on site. We spent about $345,000 on waste and recycling out of Darwin using Clean Away. Again, the Highway In and Indigenous Beverages of Australia. It was Origin's first fracturing operations in remote Northern Territory. One horizontal exploration well, which was drilled in 2015 and re-entered towards the end of last year with 11 frack stages. The shale target, hard pressure treatments, two stages per day achieved and we had zero safety incidents with a total of over 18,000 man hours. 382,000 kilometres driven with no vehicle incidents and no loss time injuries for this operation.

A key contributor to the success of this campaign was the engagement with the local suppliers, which is the Toll NT Team based out of Darwin. They also provided indigenous site coordinators that work with the water and sludge hauling teams. Toll did the vast majority of the kilometres driven for us over 200,000 kilometres from Toll. I'd like to just quickly share with you, this is the rig superintendent for Rig 185. He is a local Territorian boy. He's got a farm in the Finnish River. He's a sole trader and cattle is his business. He's at the Adelaide base at the moment. He was looking after the rig, he was working for Beach Energy in the Cooper Basin. He started with Schlumberger out of Darwin. He considers Darwin home. He's had a career spanning Venezuela, Bolivia and Columbia before returning to Australia for the last seven years. He's a keen Northern Territorian and I think you might have met him. I brought him to the Daly Waters Engagement Session and we sat at the table with the pastoral community and he very much fits in with that pastoral community.

I just wanted to highlight, from my perspective, the engagement of local people and what that means for a career. I myself started in Darwin in the Northern Territory in 1991 and spent about five years working the territory, grew greatly attached to it, and then have been out of Australia for 20 years and have now returned back to work in Australia. I just wanted to pass on our much lower key and short experience in the Northern Territory that we've had so far and what it potentially means for us. And that is it from us.

Hon. Justice Rachel Pepper: Thank you. Thank you very much gentlemen. I have a list of questions, but I think I will actually open it up to the panel first to ask questions before I dive in because I'm quite sure they'll all get answered during the course of the questions of others. Thank you.

Yes, who'd like to go first? We'll start and work our way down, how's that? Dr. Jones.

Dr. David Jones: Joe, this is probably a question to you. One of the things that's greatly concerning to us in our constituency is well integrity. Particularly well integrity post decommissioning. We've lots of studs coming from the US, which is arguing that things haven't improved with technology. Well integrity still is as poor as it ever was. Most of these things seem to use methane as an indicator of issues rather than actual water contamination. Could you comment on some of those things?

Joe Lima: Due to sustained casing pressure and so on.

Dr. David Jones: Certainly during operating, yes.

Joe Lima: First of all, sustained casing pressure occurs on the annualist of the production casing. Remember that there are several strings as the graphic that Paul showed the model is intended to show that adjacent to the aqua-fer you have cementants and casing and then you have other cement encasing strings that are inside. The sustained casing pressures that we do see are typically at the annualist of the production casing. They don't have a sustained flow, though, so in other words they blow down, and you have some migration of methane to the surface in some instances. It's one of the reasons why we've worked in developed technologies to allow for the cement essentially to shut off when it sees any hydrocarbons coming through the matrix of the cement itself. They can basically re-heal itself. I can't answer the question that technology has not improved it because I would generally say that it has. We have seen repeated technologies that have worked toward these various issues. I'm not familiar with any widespread that says that this always has been an issue and will continue to be an issue. Generally speaking, we've seen improvement in cementing quality in the states.

Remember that also, remember the other thing is that the application of cement depends upon the environment you're working in. What you're going to do is be dependent specifically to the types of fluids you're coming in contact with.

Dr. David Jones: That's it. This issue of well integrity and statistics is a recurring theme that keeps getting thrown to us. We're not experts in petroleum or of the technology of drilling. We would like some kind of definitive answer as to yeah or nay. Is it getting better or is it the same as it always was? What does methane detect mean? Does it mean an issue of human health for environmental harm potential or is it just a case of this is something that's used, an indicator, but it's not necessarily a good indicator of that.

Joe Lima: I can't answer about the human health effects and so on from it. Is it a systematic problem that is ultimately leading to health effects? I don't have that type of expertise. I will point out that you're talking about 30 some odd thousand wells that are drilled in the US on an annual basis. Of those, I think they were talking about relatively speaking small fraction of these that we're seeing these types of problems that are being pointed to. I wouldn't say that it's an example happening on every single well. If you drill a well, you're going to have this issue.

Dr. David Jones: We appreciate this, but we've seen some statistics for example from King and King which-

Joe Lima: I'm sorry, who?

Dr. David Jones: ... King and King that produce a paper I think in about 2013, which suggested that the issue of total well bore failure was about .004 percent yet other protagonists are coming up saying that the issue could be as high as 6% or even higher. So, are we comparing apples and apples? I think that's the key number to question.

Joe Lima: I can tell you that the proper use, I feel firmly on this, that the proper use of technology you can achieve the goals of properly sealing off of formations and that the technology allows you to work in an environment where you're constantly stressing the casing, changing the temperature and so on and so on. So, again, it's the proper use of that technology that allows you to achieve that goal. Can I say that we're always seeing that proper application? There are going to be instances where folks haven't applied these things correctly. I think it is a matter of understanding the environment you're working in and saying what tools do I need to property do it. I think it is achievable, I think it's achieved more often than it is not.

Dr. David Jones: Just a follow up question on that is post decommissioning. We have the perception from the community that at the end of a well's life, that it's something like a genie in a bottle. Unless it's plugged up really well, that you're going to have to pop the cork and things are going to come up the well bore. Is that the case or have the assistance been so depressurized that that's not likely an issue?

Joe Lima: I think you do have the advantage that you've depleted the target reservoirs and when you're plugging the well, you're no longer in a commercial state that you have the benefit that you don't have that same amount of pressure being exerted in the overall system. I've heard the question before about is there a hundred years from now what does a well look like? There aren't a lot of examples of that. And plain and simple, there are not a lot of examples for us to even rely on. I can tell you that the ability to go out there and understand if you have a problem in a string of casing. In other words, looking at the corrosion in casing or does the cement exist behind casing and so on. Those technologies exist. They're tried and true, and that the application of those technologies will allow you to understand what you're dealing with.

The cement systems themselves, if you end up ... Let's just say the part where we call a primary cement job is the first application of cement into that well when you're trying to cement the casing. A remedial cement job is when you're going in and fixing a problem. Maybe you have some sort of place where the casing was laid up close to the formation and you have a channel there. There are cement systems that are specifically designed to allow you to get it to those places, so the processes of going in there, perforating the casing and then doing what is called a squeeze job to squeeze that off exists and so it is that type of application that allows you to achieve the goals you're intending.

I don't know of any examples, I cannot think of a single example at this point of where somebody said, "Oh, you know here's an old well. We've had to go back in or we're going to have to in and fix it. It's been plugged for some time." I don't know of any examples like that, but in theory, if you run across that I think you can go back in and fix that problem so it doesn't become a perpetual issue.

Hon. Justice Rachel Pepper: Yes, Dr. Priestly.

Professor Brian Priestly: Thank you for the information you've provided on the disclosure of chemicals used in the process. Hopefully we'll have access to the slide so that information can be captured. I have a two-prong question really. The first relates ... in some of the submissions we've had, we've had allegations that depleted uranium is used in some of the fracking processes. If this is the case, what is the function of that depleted uranium? How is it used and how important is it to the process? The second part of my questions is that there's also been an allegation that Schlumberg's was fined for having some of its workforce in Queensland exposed to radioactive materials. If that is true, can you explain the circumstances under which that actually happened?

Joe Lima: I am unaware of the use of depleted uranium in fluids. I have not heard that before. So I can't really answer that question. The second piece, if you don't mind repeating what was the case here?

Paul McDougall: I'll take that one. It is a legal matter. I would prefer to get the appropriate legal representation. I'm happy to connect you with them and you can have that discussion.

Professor
Brian Priestly: You're not able to describe circumstances under which it may have occurred?

Hon. Justice
Rachel Pepper: It’s been dealt with, heard?

Paul McDougall: It's been dealt with as, and heard, and I'm not an authorised spokesperson to handle that. I'd be happy to connect you with our legal counsel who can go through those circumstances with you.

Hon. Justice
Rachel Pepper: If you wouldn't mind that would be good.

Paul McDougall: No, I'm happy to do that and I predicted that question and I have this answer ready and happy to connect you with that individual, if you don't mind.

Professor
Brian Priestly: Ok.

Hon. Justice
Rachel Pepper: Yes, Professor Hart.

Professor
Barry Hart AM: I had a question on the well integrity. You mentioned proper use of technology. Everything was A-OK. How do you describe proper use? How would you expect it to be ... What are the sort of guidelines? Do you, around the world, what other various jurisdictions have to ensure that one, we know what proper technology is. The best available and that it's actually being regulated.

Joe Lima: What typically happens when you're developing a play is that you look and you say, "What other plays around the world are analegist to this?" And then you may start from that point. You say this particular play in Northern Territory is similar to say, as an example, the Marcellus. You start saying that from a reservoir perspective. That's really where the relationship stops. When you get into a specific field, you do have to understand things, especially with cementing, temperature anomalies. You have to understand; do I have any corrosive fluids that are native to the rock, to the formations? Whether it's the producing formation or any other formation that you've intersected. What do I have ... Am I going to encounter anything that's ultimately going to either have an issue with the cement or I'm going to have an issue with the casing itself. In other words, if that fluid get to the casing-

Professor
Barry Hart AM: Sorry to interrupt.

Joe Lima: Yes, sir?

Professor Barry Hart AM: I understand all of that, besides specific situation, but I'm trying to work out how then the knowledge that exists within your companies and like companies. Number one, the regulators know about it and can act on it. Because, otherwise the juxtaposition between what might be the right technology on what's putting guidelines regulations or whatever, and then the community feels happy that the regulator is on top of things. That's broadly where I'm going.

Joe Lima: Remember that these wells are intended to produce for decades. The operators of the wells, their goal is to get that piece of this. The time that you have to get the cementing done right is the very first time around. I was getting a little of a long-winded answer to your question. I don't believe that, in my experiences, I don't believe that the regulations will describe what the cement systems need to look at. It's the experience that you have at the field about the conditions I'm working in. Then deciding upon which cement systems and so on make the most sense to use. Even again, our models allow us ... We use these things as best practise. There are requirements on testing. Some of those requirements are our own testing. Some of them may be jurisdictional, but we have certain protocols on how you apply these things to the cementing design process. But then, once you've applied all these things, it's a matter of having all the right experienced people and the right equipment to physically get that placed.

The decision ends up being like with folks like Daniel based upon what your experience is in the field. That particular field, and then working through the depth of knowledge that he has but also other folks within the company has. So, one of the things that Schlumberger prides upon itself is that we work all over the world. We work on many, many wells and we have some internal communication systems that allow our technical folks to ask these questions of experts throughout the company. Essentially you're virtually tapping into experience from all around the world. You have something that's unique that's occurring, you can go and ask the question. Has anybody else dealt with this type of thing?

Again, once you get to that point where you designed this cement treatment, then it's going to vary from well to well to well based upon the unique circumstances that you're running into. But it's all these things. Cementing isn't just as simple as going out there and mixing cement with water and pumping it. There's a lot.

Professor Barry Hart AM: No, no, I understand all of that. The background to my question is, we have had submissions and communal consultations and I can tell you the great majority of people out there and the unwashed if you like, don't trust companies and they don't trust governments. We're very keen to think about what are the processes that we can put in place that might assist that confidence. That's all. So, let's leave it at that, I think that's fine.

Can I just ask you another question, it has to do with operations and difficult conditions. You showed the one in Colorado show in the winter. We've got the similar, if you like, but different wet season and we've been putting it to a number of organisations. The Origin and Santos and so forth. What about not necessarily operations, but no hydraulic fracking during the wet season? Because, you brought up the whole transport situation. Most of those guys, as I suspect, were paved roads. We're going to have one paved road and then the rest of it, and the pastoralist know that they essentially do nothing during the wet season. What's the story there do you think? No operation?

Joe Lima: Well, so we run into that, right? We run into this in places like Canada when they have that transition from the Winter time to the Spring, the break up. Yes, operations stop at that point and mostly it's because of the impact it has on roads and so on. Now, we have run into places where we know that we are going to need a lot of sand for hydraulic fracturing operations and this is in the US and yes, this is you know paved roads and so on. But again, driving down a winter road when you're sharing it with school buses and other things, you have to think about these things. What we did to solve that particular issue is that logistically we built a facility that allows us to go and get the resources we need closer to the field and then be able to transport them a shorter distance instead of utilising the network of roads. It's those logistics.

It's not just what you're physically doing on location, but a lot of this is around logistics, the transporting of resources and so on to location. That planning's important. But the other thing is that we're continually striving to how we can do these same types of things. How can we achieve these things with less resources. That is our goal. As I mentioned to you earlier about the importance of surface contact with the formation, that's what drives reservoir performance. The physical creating the hydraulic fracture and so on, we've continued to look at technologies that allow us to do it more efficiently with less water, less propent. So the application of those technologies is a potential, in some types of environments. I think that ultimately if you're looking at some concern with the roads, what little roads there are those other areas or the potential impact to the environment, you may end up having to consider doing something like that.

Professor Barry Hart AM: No operations, yeah.

Paul McDougall: If I could add to that if you wouldn't mind from personal experiences as a result of extensive flooding in the Northern Territory, that Joe, it's incredible actually how much of that country does flood. We have similar experiences in Queensland during the wet season there and you can't plan your activities to constrain it to area of high ground. You can stock pile. It really becomes a logistics optimization exercise. We work in many jurisdictions around the world and can manage all sorts of logistical constraints. It's a matter of whether it's a cost-effective way to proceed. This would really be an operative decision that we could fit into. They may hand some of it to us, Schlumberger, see if you can plan about putting a rig on this high ground for three or four months while it's flooding and what can we achieve in that period of time.

Professor Barry Hart AM: It's the planning. Just one more if I may. It has to do with the fact that where we are at the moment in the NT. I know there's a couple of wells and that's it. The question is around strategic roll-out. Have you any experience of ... Understand what I'm getting at that it is very, the hypothesis would be the roll-out of the industry, the unconventional in say in the beetaloo is very well controlled by an independent authority. Are there any other examples that you know of around the world where that has occurred? We get the comments all the time about the uncontrolled development in Queensland, et cetera, et cetera and I don't know, I don't have experience of Canada and the states but you get the same sorts of situations.

Paul McDougall: Yeah, so I think that there are some natural constraints that occur, specifically about where you are in the development process today, which you're not in development, you're in exploration and maybe into an appraisal type phase. What I try to articulate some of the slides here, was that on the field development perspective, it starts out slowly because you have to build that model and before you can get to where you're doing large scale development with a lot of wells, you have to understand what you have. So I think that there is a natural constraint. I can't think of any specific examples anywhere where that's happening by design as opposed to just happening from a natural perspective.

Professor Barry Hart AM: The knowledge build up.

Paul McDougall: Right, knowledge build-up that takes it slow. But again, remember that it is, in our perspective, the most of our customer's perspectives it is about being efficient. You'll look at building pads where you can for multiple wells and drill off that type of plan scenario. I think many of the images that folks are leaning upon and saying the uncontrolled growth ends up being some of the vertical wells and so on that occurred in the last generation of oil and gas development in the US. I keep on seeing those pictures popping up as examples, and they're not the contemporary of what's happening today.

Professor Barry Hart AM: Thank you.

Hon. Justice Rachel Pepper: Maybe just following on from some of the questions that Barry then asked. We know that there are problems in Texas. We know that there are problems in Queensland. We know this because we know that arguably that social licence has been lost, or social contract, to use your words. In Australia, we have a moratorium now in place in WA, we have a moratorium in New South Wales and we know that there's gas in both those jurisdictions. It's banned in Victoria where how much gas there has been in Tasmania, a moratorium in the Northern Territory. There have been problems. That's what spawned, really, organisations like Lock The Gate and others. What went wrong in those jurisdictions? Why is your industry now very much on the back foot?

Joe Lima: Two things. My personal experience is what keeps me up at night is not what we do, it's what people think we do. That's the big concern that I have, and the other half of this is that generally speaking, engineers do a very poor job of communicating with the general public. I think that our ability to go out there and communicate what's happening, and maybe there's an inherent mistrust for companies and so on. I think that that is ... We're being outpaced by folks who don't want to see development versus folks who understand clearly what we're doing. I'm a firm believer that knowledge is the power behind doing these things correctly, and that if you understand these things, you can engineer things correctly. So I think to answer your question, the big issue I think is taking some examples and using them out of context the same as a systematic stomatic type of issue that you're having that's going to follow you to Northern Territory or anywhere else.

Hon. Justice Rachel Pepper: Well it's more than that though, isn't it. There is this truly to sort of overly simplify this, there is no smoke without fire. We know that there are environmental and social problems that exist in Texas, that existed in Queensland. I'm not looking for an answer that's prospective, I appreciate the technology has changed. I appreciate that the way things are done now even from a social perspective have changed, but what happened? Putting your glasses on and looking back, why did things go wrong? And they did go wrong.

Joe Lima: Again, I'm a believer. The things that I've been involved and the things that I've seen have been primarily a miscommunication, misrepresentation of what's going on. I think that there are quite a few studies out there and I look at this that if you really want to look for something that says that something's not working, you'll find something to support your belief and then that's what you'll use as a banner. I don't believe that we have a systematic issue in the industry that is going to again say that just because you're doing unconventional development on-shore in a given area you're going to run into the same problems you ran into in Texas or in Queensland or any other place.

Hon. Justice Rachel Pepper: I'm not asking you that. I'm asking ... First of all do you accept that there are problems in Texas and Queensland? Just to pick two jurisdictions.

Joe Lima: I'm not sure which problems you're referring to. If you could be more specific, I'm sorry.

Hon. Justice Rachel Pepper: Well, in Texas there are instances of aquafer contamination, health problems. I think it's fair to say in Queensland as a result of bad practices between gas companies and land holders there was a lot of stress and anxiety created in those communities. So we know that things went wrong. I guess I want to know why you think that is. What it a failure of regulation, or where the regulations there and they weren't followed? What are your learnings, I guess?

Joe Lima: What's changing, what I see happening with EMP industry in the US is that they're changing how they're communicating. The cases that I think you're referring to, of ground water contamination, health effects associated with oil and gas are that you may have a study that says that this has happened and you'll have other studies that say no, this hasn't happened. So I keep on seeing these conflicts as far as what the real results are of these various studies. First of all, I think our industry is extremely innovative. We continue to share best practises and some of the things that you're hearing as far as plans by Origin and others are derived on some of the better things that have happened out of North America. How you drill, how you complete pads, the proper use of fluids, chemical disclosure. All those various things. So I don't see that as being a problem. I will say that in the US, many of the regulators they work together from a standpoint of helping each other understand what the regulations look like.

There is an effort that exists through the Interstate Oil and Gas Compact Commission called Stronger. I don't remember exactly what the acronym stands for, but basically it's essentially a peer review of the state regulations. If you're the head regulator in a certain jurisdiction, you can say, "I'd like to sponsor, to have a review of the regulations." The other jurisdictions will basically come in and they'll look at what's on the books and they'll say, "Here are the places where you have an opportunity for improvement." You do see that there is somewhat of a march that commonality between jurisdictions based off of those types of things. They do listen to what's happening in other places, in other states.

Again, to go back to what you mentioned before, I would say that the studies that you're referring to about ground water contamination and so on, I have seen studies have also said no, that's not because of this particular thing, so you didn't do this, right? You can't say that it was definitely that happening. Industry wants to continue to have that social contract, obviously, the ability to go out and have that trust. It is somewhat of an uphill battle to gain that trust. And again, that's why we see that many companies have the social programs, these programs to try to communicate what they're doing and what their plan is and participating with the communities, and so on and various things because they're trying to build a trust, have open dialogue, open lines of communication and so on.

Hon. Justice Rachel Pepper: Thank you. Perhaps just on the regulation thing, what are your experiences or what would be some of the toughest jurisdictions both in North America and Australia.

Joe Lima: I'm sorry, the toughest?

Hon. Justice Rachel Pepper: Toughest. The most onerous, most inefficient or expensive, perhaps to dwell it down, regulations to comply with? First in North America and then in Australia.

Joe Lima: That's a tough question. What is the toughest one?

Hon. Justice Rachel Pepper: What was the most difficult? As I said expensive?

Joe Lima: I've lived in Colorado. I'm more intimate with what happens there from a regulatory perspective, and remember, I'm speaking from a service company perspective. My personal experience with this, I see that Colorado has been very progressive and they've come up with things like fugitive methane regulations and so on ahead of others. Many of these things, industry voluntarily worked with the regulators to develop. Here's a problem that we're all trying to address. They're coming up with something that makes sense. I can't say for a fact that it's more onerous because we're not the entities that ultimately are living up to those specific regulations.

Hon. Justice Rachel Pepper: Thank you. Yes, Dr. Beck?

Dr. Vaughan Beck AM: I just wanted to continue the theme of abandoned wells. I've got two questions. One on abandoned wells and another one on rigs. In terms of abandoned wells, I've recently read a paper from the United Kingdom reporting on some 190 odd wells that have been decommissioned, so the removal of infrastructure and burial. They measured the methane emissions at the surface in the soil and there was a very high percentage of leakage wells. It wasn't a few percent, it was 10's of percent, could be 40%. I just can't recall the figure. There was a distribution, obviously, with the amount of leakage that was going on.

And they found that leakage occurred fairly early in the life and it wasn't a function of the age of the well, it was more that they happened fairly early. If they're going to leak, they leaked, and they leaked reasonably early in the life. I'm coming at this from a perspective of social licence to operate. There's evidence that there are problems and these are not abandoned wells, these are decommissioned wells, according to UK regulations. Rigorous de-commissioning requirements. We've got evidence of leakage, and they were speculating as to why they were leaking. Cement was clearly the one, they were speculating there could be leakage from gas seams higher up rather than low down. They were speculating as to how to try to prevent this because at the moment we're talking about a social licence to operate. We have evidence that there are significant leakage problems, and we can't dismiss that.

I'm looking to get some suggested solutions how we can overcome this problem so we can try to alleviate community concerns. Now, interestingly, in the paper they did suggest something that you had noted was the use of ... But in a different context was in you were talking about remediation of wells and perforating the casing and squeezing the cement. They were, I think, suggesting using that as a more routine procedure to try to overcome these fairly high percentage of leakage. I'm looking for suggestions as to how we can get procedures in place because current procedures clearly on the evidence are not working and what we can do to try to develop a social licence to operate. Because, if we don't do that, there are going to be problems.

Joe Lima: I'm not familiar with the case you're talking about, but I'm assuming these are in the UK.

Dr. Vaughan Beck AM: It's in the Oak literature.

Joe Lima: Schlumberger, just to give you a little bit of an idea of where we sit from a regulatory perspective, we don't lobby. We're A political and so on. I'm not going to go out there and tell you that this is the regulation you need to put in place. Again, the common theme that you're going to hear from me is that the proper use of technology I think is going to be the type of thing that enables us to reduce the likelihood of these things happening in the future. I'm assuming, when you say these are decommissioned wells, these aren't wells that were drilled last year or last decade, but they may be 20 or 30 or 40 years old. So the technology most definitely from when I started working for Schlumberger, nearly 30 years ago to today has significantly changed. It continues to become better, again, as I mentioned earlier, I believe that the application of these technologies, if you were to do the same well, the same environment today, use the most latest technology, you'll end up with a better environment that you ended up with before.

What those regulations, I think ultimately look like, I think it's going to be up to the regulators in the Northern Territory. I cannot comment about what they should ultimately look like to prevent this type of thing happening.

Dr. Vaughan Beck AM: The difficulty is that you said that you believe and we're looking for evidence. The community has beliefs, too, and those beliefs are sometimes quite diametrically opposed to your beliefs, and we are here in the middle trying to get a position. If you're not prepared to make suggestions, then who is?

Joe Lima: Again, there's no way for me to tell you what that needs to look like. We can't, by design, dictate what those regulations would look like to make that happen.

Hon. Justice Rachel Pepper: You can't dictate, but surely you can suggest solutions. Surely you can suggest solutions, because otherwise, maybe there would be a better recommendation, an unfavourable recommendation is made by this panel on the basis of an absence of any data or evidence or techniques, or recommendations coming from industry. So far we keep having industry giving us quite bland statements of it's for us and so on. That is not helping.

Joe Lima: I understand that.

Professor Barry Hart AM: Can I just add to that. You rightly keep making the statement about proper use of technology. We probably agree broadly with that, but what is the proper use that we're trying to scratch out here. So, you might not want to comment on regulation, but sure and the goodness you can tell us in the case of Vaughan's question about abandonment and leakage and methane. What is the best technology at the moment that we should be looking to ensure the industry goes ahead is put in place.

Joe Lima: My recommendation is that you talk to the folks who have a vast experience with regulating those types of environments. Remember that in North America you're dealing in excess of 30,000- 40,000 with Canada wells per year that are being drilled in the various jurisdictions. They have a long history of doing that and that the regulations have continued to evolve from what they were 30, 40 years ago to something that is addressing the contemporary applications today. I think, my personal perspective, not from Schlumberger's perspective is that they're probably the right entities to visit with. What are the things that you've seen that have worked best to solve these various issues? But again, remember from where I started 30 years ago, the technologies have continued to evolve. How we do things have continued to evolve and 30 years from now they're going to look different again. But they continue to address the biggest issues that are were we're being faced with.

Dr. Vaughan Beck AM: Our position at the moment would be on the basis of the evidence we could get to the point where we could recommend that there must be a universal perforation and squeezing of cements on the basis of the evidence that we've had.

Joe Lima: Yeah, well again, I'm not familiar. I don't think that there's enough wells, first of all, for me to be able to draw a conclusion that that would be the proper thing to do in that specific environment. It may be something that is unique to that reservoir that that paper said. Maybe there is a shallow play that is highly charged that is pushing the methane to the well bores. The well bores are just acting as a more conductive pathway to the surface than the natural matrix of the Earth. I don't know. I can't answer that question. But I believe that the application of regulations should be specific to the environment that you're working in because otherwise they become something that is, "Well, why are we doing this?" Well, because some half way around the world in a completely different type of horizon was doing that.

Dr. Vaughan Beck AM: Appreciate it, Thank you.

Daniel Kalinin: If I may, I'm not necessarily agree that the current regulations are not working. For example, if cement is not adequate at glance as they're not allowed to produce the well, to curate the wells in Queensland.

Joe Lima: Sorry they're not allowed?

Daniel Kalinin: They're not allowed to produce a well unless cement is adequate. They would have to do a remedial job to restore, cement it to integrity. To your questions, what is the technology for the abandonment? I recently presented the case in Darwin from North America where they had the high H2S content in the gas and the well was located in the vicinity of a school, so they use a cemented technology to describe it, which was like a self-healing cement is with flexible properties. That was successful, they put several plaques and there are no issues, they use it on a number of wells. I can provide to you further information on this.

Dr. Vaughan Beck AM: That would be useful if there is some pipes that are in the open literature that can describe this self-healing properties of cement and the performance of such, we would welcome details of that literature.

If I may move one, second questions to do with rigs. You mentioned 30,000 rigs or wells are being drills in the United States, just interested to sort of get an indication of how situation will develop in Australia where if we get into the production stage and at the moment, as I understand it, there are only a handful of rigs in Australia that can drill horizontal. Given the demands that are going on in the United States, is Australia going to be left with only a couple of rigs or how can Schlumberger build up to the capacity of getting up to 50, 100 wells drilled per year.

Paul McDougall: We have rigs sitting around now.

Dr. Vaughan Beck AM: You have rigs?

Paul McDougall: Yeah.

Dr. Vaughan Beck AM: How many? In Australia?

Paul McDougall: Yeah. They're not all deployed down.

Dr. Vaughan Beck AM: Can I ask how many?

Paul McDougall: The exact number is changing on a day-to-day basis, but we probably have five drilling at the moment and there's three or four that are stacked, not operating. And industry overall, there's many that are stacked. There's an excess of rigs at the moment.

Dr. Vaughan Beck AM: Capabible of drilling horizontal wells?

Paul McDougall: Not all of them are. And there's also the depth.

Dr. Vaughan Beck AM: My question is, in order to be able to meet some of the projections that are being given to us in terms of production in terms of drilling wells, is there and will there be sufficient drilling capacity in Australia?

Paul McDougall: Again, there would be significant technical gateways for the operating companies to get through and then plugging that into their commercial model and if that stacks up, we will get rigs available depending on the commercial outcome. That would be the short story. It will be the economics of the overall development of the project if it is significant, which remains to be seen, don't have enough data at this point. The same way that we ramped up for drilling activity in CSG, I anticipate that we can do something similar, with a different rig spec and design. It will be a completely different logistics story with some very remote operations. We're a service provider. We enjoy that kind of operating in that it's more challenging, more difficult and that's kind of what we do.

Dr. Vaughan Beck AM: Thank you.

Hon. Justice Rachel Pepper: Yes, Dr Anderson.

Dr. Alan Anderson: Thank you. I've got a question about well-pad spacing. It's in the context of community concerns here about risks of industrialising what are currently iconic Northern Territory landscapes. Obviously, distances between well pads is a key determinant of landscape transformation. Mr. Lima, you've talked about well pad spacing in your diagram of regulation evolution. I was wondering if you'd give us some information about the extent to which there are minimum spacings between well pads and regulations and different jurisdictions and where things are at in North America.

Joe Lima: It depends on the type reservoir, but obviously the tighter the formation rock you're trying to produce from typically the closer that you end up with parallel wells. If you're not draining very effectively you essentially add more wells to it. The US experience, I think, is a little bit different in what you would see in Australia from the standpoint that much of the land is being leased and you have to hold production, or hold the leases by producing from a given area. In some instances, you end up with early on, one well and then another well not very far off but basically helping to hold the lease from a production perspective. I've seen operators working in the US and when they've had the land leased up and so on and they get into a development process, they basically work somewhat of a factory and it knew that term could make people nervous but the idea is that you're working systematically across a play. Instead of drilling some wells all over the place and not to hold the production, hold the lease, you would actually work your way across this play, let's just say from the east over to the west. And, that you end up drilling so many ... Building pads to do so.

What's common today, the vast majority of the wells that are being drilled in the US I think it's in excess of 90% are either horizontal or they're directional in nature. Vertical wells are the minority today, where 15 years ago that was what you normally saw happening. With that, the ability like that one image I showed you underneath the city of Greeley, Colorado in the US, the ability to go out there and start a project by putting locations off in different places we're drilling up underneath these places to stay away from the places where folks don't necessarily want to see a development happen on the surface. We see that happening more and more. We've seen drilling underneath the airport in Dallas, Forth Worth, but obviously off from the side and drilling out underneath and so on. So that development, there's lots of opportunities. Directional drilling has allowed us to be very creative about how you place things.

There are some other things that can strain what this development looks like. Namely that if you were to drill, let's just say a well site with 10 wells on one common pad, is that typically you're not going to go out there and drill and complete and get the all producing at the same time. The reason why is because you have to build your production facilities to accommodate the peak production on all 10 wells as opposed to going out there and having a smaller facility that can accommodate lesser production. Remember you have a natural decline on a well's productivity. All these things go into the philosophy on how you're going to place wells. Typically with horizontals what we see happening is anywhere from two to 20 wells on the location. They typically will obviously go, you know you can drill let's just say off to the south in one set of wells and a completely unique set of well heads and well bores that are drilling off in 180 degrees, other direction.

Again, the advantage that all the production for those wells go to one location, so that's typically what I think you're going to see happening. Again, as far as the spacing of well to well, it going to depend upon how effectively you're producing these things. Typically, you might see that spacing starts out, let's just say for argument sake, it starts out at 160 acres spacing between wells to where you get down to eventually 20 acre spacing as the field continues to mature and you get an understanding about interference from a production perspective between the existing wells.

Dr. David Jones: I can understand that there's all sorts of technical and commercial factors determining the spacing, but I was thinking more in terms of regulation in the context of avoiding major landscape transformation from an immunity perspective and so I guess my question's very specific about is that regulated. Are there examples of where it's regulated in that context or not.

Joe Lima: I have not seen examples where that's required. I know that you shall do it this way and so on. But I see that that's happening in practise. Most of the operators, there's one operator that I work fairly closely with that sends its engineers to a potential location at night to see if the headlights shine through people's houses. That philosophy, even though the regulations doesn't say so, the philosophy exists that they're trying to minimise the impact on stakeholders. Whatever they are, whether it's wildlife or it's a community that's being engaged. But I can't think off the top of my head, I cannot think of one that specifically says you can't drill over here and so on. There are some requirements in urban environments in North America around distances. Setbacks from homes and schools, that type of thing. There's also some requirements around things like noise and noise levels.

Dr. David Jones: Thank you.

Hon. Justice Rachel Pepper: We're wildly over time. Thank you for being patient. Part of the reason why that has occurred is because I appreciate that you've come a very long way.

	Some of you have come from very long ways to attend here today and we're very grateful for the time that you've given up and the presentation. We'll be able to get a copy of those slides?
Joe Lima:	Yes.
Hon. Justice Rachel Pepper:	Great. But again, thank you very much for answering all of our questions to the best of your ability and we appreciate your time, thank you.
Joe Lima:	Thank you.
Paul McDougall:	Thank you. Just by way of housekeeping, who should I send? (silence)