Jesse Green: All right welcome to the risk panel discussion. I'm Jesse Green with the Enrichment Center. With us today to address and discuss the risks of hydraulic fracturing are Charles Stanley, Chairman, President and Chief Executive Officer of Q.E.P. Resources. Q.E.P. is an independent natural gas and oil – and oil exploration and production company with operations focused in the Rocky Mountains and mid-continent regions of the United States.

Also with us is Timothy Fitzgerald. He's an assistant professor in the Department of Agriculture Economics and Economics at Montana State University. He holds a Ph.D. from the University of Maryland and his research interests cover energy, environment and natural resource economics.

And we have Michael Levey from the Council on Foreign Relations. There is the David M. Rubinstein senior fellow for energy and the environment. He is CFR's direct of the program on energy security and climate change. He holds a Bachelor's Degree in mathematical physics, a master's in physics and a Ph.D. in war studies from the University of London.

Thank you all for being here. Just to remind everybody, please pass your questions to the aisles on the outside so that we can read those and be prepared when the Q and A comes. So bring those down as soon as you're ready.

I would like now to ask Chuck Stanley to take us through his presentation to help us understand this technology a little better.

Charles Stanley: Thank you, Jesse and good morning everyone. First I'd like to thank Dean Schizer and Professor Merrill for inviting me to engage in this discussion. I think it's a great forum. I look forward to the panel and I obviously enjoyed the panel earlier this morning. I thought – I'm a geologist by training. I don't have a Ph.D. so I feel rather undereducated here. I thought I would use a few diagrams to help us develop a visual image of hydraulic fracturing and drive home a few key points. A little bit of history. Hydraulic fracturing goes back, as Dean Shizer pointed out in his introductory remarks, a number years back to the 1940s. And the first wells that were hydraulically fractured stimulated were vertical wells and most of them targeted very poor quality reservoir. So it was a basically a technology that was used to extend the reach of well bore out into the reservoir to enhance the production of oil and gas from poor quality reservoirs.

First single stage fracture stimulation and later on in the 1990s we perfected technology that allowed us to do multiple fracture stimulations back to back in the same well and then drive out plastic fracture plugs and allow for comingling of different reservoirs and simultaneous depletion of a number of different sands or tight sands in this case, simultaneously, which really drove a huge revolution in tight sand development in the United States.

Later on we married additional technology – an evolving technology, our ability to precisely drive and steer the drive bit over long distances, first directionally and then horizontally. This was technology that was developed in the – off shore in the Gulf of Mexico and other places around the world, the U.K. North Sea, etc. But by marrying direction drilling and horizontal driving in multi-stage fracture stimulation, we were sudden able to attack not only vertical wells and stack sands, but also horizontally target reservoirs that were poorly productive or uneconomic without fracture stimulation. Tight sands, horizontal tight carbonates, we talked about Bakken Shale, and everyone says Bakken Shale and we think of it as being actually a shale oil source, but in fact the Bakken is a sandwiched reservoir, very poor quality carbonate reservoir sandwiched between two shales. And the horizontal wells are actually drilled into a very poor quality conventional reservoir and then multi-stage hydraulic fractured and that is responsible for a huge increase in domestic crude oil production in the United States.

And then lastly, horizontal shales, and of course a number of them have been mentioned today, the Marcellus being very close to New York. The first horizontal shale development – commercial scale horizontal shale development was in Texas in the Barnett Shale, around the Dallas – Fort Worth area and then, of course, it extended into to other shales, the Haynesville, the Fayetteville, the Eagle Ford down in South Texas. So these are the basic types of what we call – what we used to call, I guess as a technical person, unconventional resource plays. But what we call unconventional ten years ago is now very much the norm.

So what is hydraulic fracturing? I think we've already – in fact I would like to nominate the dean for an honorary geology degree because I think he did a quite good job of describing the technology. What is it? It's injecting fluid into – and a proppant, either sand or ceramic proppant into the well bore at high pressure and the idea is to create cracks in the rock and prop open those cracks so that you synthetically extend the reach of the well bore into the surrounding reservoir. The interesting fact is that almost every well drilled onshore U.S. today in over the past 10 or 15 years is being hydraulically fracture stimulated. Without hydraulic fracture stimulation, the vast majority of U.S. onshore gas production today would be uneconomic. The process has been around a long time. As many of the panelists before me have pointed out, the thing that has changed is the scope and scale. And I'll talk about some of the impacts around that. Over a million wells in the United States since 1947 have been fracture stimulated. The fluid composition, we've already heard, mostly water and sand with a small percentage, usually about a half of a percent or so of additives and those include things like soap, anti-bacterial agents, etc. as well as in some instances, guar gum which is the same stuff you find in toothpaste and some cosmetics to help carry that sand into the fractures.

And so it's this marriage, as I pointed out earlier, hydraulic fracturing along with directional horizontal drilling that's been the real key to unlocking a huge renaissance in the oil and gas industry in this country. And as my predecessor, colleagues have already talked about, there are a number of risks and impacts here that we need to consider. Some of them are not unique to oil and gas – not unique to hydraulic fracturing, but rather just part of the whole oil and gas extraction process. One of them is well construction integrity. It's very important not only for the process of hydraulic fracturing, but when you think about an oil and gas well that can last 40 or 50 years, the mechanical integrity of the well is absolutely paramount to isolation the hydrocarbon that we're extracting from the ground from drinking water aquifers as well as from the surface. Water use is a big deal, as the governor would point out to you in states like Wyoming where water's a very scarce and valuation commodity, we're very focused on that. But the industry in general has become focused on it even in areas where there's an apparent abundance of water because of our concerns about impact.

The handling of flow back water, which is basically the water that's pumped into the ground to crack the rock, as well as the associated water, all oil and gas production comes up with some water. There's water that lives in the rock with the oil and gas. When you produce an oil and gas well, water comes to the surface, and that's a very important part and I'll come back to that in a minute.

Surface disturbance, we have an impact on the surface and so the focus on industry on minimizing surface disturbance is very important and then long term production operations: trucks, vehicles, people in areas where maybe in the past folks haven't been accustom to us. Emissions associated with the drilling and completion of wells and then long term production of wells and the impact of those emissions on air quality are also important. And then traffic and other human impacts, especially in states like Wyoming where the population density's very long in a town like Pinedale Wyoming, with very small populations these rapid influxes of people who are not from around here and it does have an impact and there's some things that we've done that we've learned from our experience in Wyoming that I'll share with you.

First of all, when I think of hydraulic fracturing, I think of it as part of a continuum of the well construction process. The drilling of the well is the first part. We move in a drilling rig, we drill a hole in the ground, we cement steel casing in the ground. When we cement it we actually pump concrete down the hole and out around the outside to cement that steel casing very tightly in the rock. There are multiple strings, or multiple continuous strings of casing that go from the surface all the way to the bottom of the well bore. Each one of those is cemented in place. That's important not only for hydraulic fracturing, but as I pointed out also for the long-life production of the well. 40 or 50 years we have to maintain that isolation of the hydrocarbon that's coming out of the ground from the surface and from drinking water aquifers.

We have lots of technology. We talk about technology that's allowed us to unlock oil and gas from this very difficult rock. We also have evolved a series of tools that we use to evaluate the integrity of the well bore, starts with the types of cements we use, our ability to inspect those cements once we place them between the steel casing and the rock, observations about the rock quality and integrity of the rock from cores, from all sorts of remote observation that we can do, including microseismic studies as we're actually placing the fractures. We test the casing before we ever pump anything into it for pressure integrity and we do that not only prior to fracking, but also during the life of the producing well. We can look at the pressure between the individual strings of casing and we can detect any leaks, even if they're very small leaks that develop, we immediately stop production and fix those leaks over the life of the well.

We also have electronic and other tools that we can run inside the casing to observe the integrity of the casing. Any erosion or corrosion that's occurring over the life of the well, which also provides for a lot of comfort from the operators perspective on the well bore integrity.

There's been a lot of discussion about water use. I found this slide from a U.S.G.S., U.S. Geological Survey publication back in 2005 that sort of looks at the various uses of water in the United States and it may be hard for you to see, but in the front little pie there you can see that the mining and oil and gas industry in 2005 used about 1% of the total water consumed in the United States. It's a very small part of the total water use. That being said, in some places it can be a significant impact and so places where we can minimize that water use by recycling and reusing, we'll do so.

I'm getting the five minute high sign. Thank you, Jesse. I'll talk faster. I have 25 more slides to go, so don't worry, I'll finish up on time.

So let me give you a couple of examples because I think graphics here really help. So Pinedale, Wyoming, largest gas field in the Rockies, the gas producing horizons are about 7,000 to 9,000 feet below the surface, so they have lots of intervening layers above them. And this is a one to one diagram, so the vertical scale here shows the relationship. 7,000 to 9,000 feet to the top of the gas bearing horizons, and the gas bearing horizons are a series of thin, discontinuous sandstone bodies. Think of it like a bowl of potato chips filled with gas, a little bit bigger than potato chips, but nevertheless, the same visual image and that gas bearing interval is about a mile thick. And what we do is we drill a well into that gas bearing interval and then we frack that interval with about 20 separate frack stages. So how much water do we use? Well, if I say a million gallons or three million gallons folks, I don't know what a million gallons looks like, but I do know what an Olympic size swimming pool looks like, and so the volume we use in a typical Pinedale well is about the size – the volume that's contained in an Olympic sized swimming pool. So that sort of puts it into context and that's about a 47 foot cube. And if you think about that divided by 20, it's about a 17 foot cube for each individual frack stage.

So what does that look like if we put it on the same vertical scale? So this vertical scale here is 14,500 feet. I don’t know if you in the back can even see the little red dot as it appears, but that’s the total volume of frack fluid that we pump in a typical Pinedale well. And I put this slide together to help you understand the very infinitesimal likelihood that that volume of fluid can make its way vertically from 9,000 or 10,000 feet below the surface. So it – I think it helps to think about scope and scale here and what happens when you pump that fluid in the ground. Very little. It cracks the rock, it stays in the interval and if you have the well-constructed properly, it doesn’t come to the surface.

Another example just to put it into context, a slightly larger cube about a 66 square foot – or cubic foot cube – 66 by 66 foot cube for the Bakken, and again, pointing out to you the total volume of fluid that we pump in a Bakken to scale down in the lower right hand corner there. A very, very small volume of water being pumped into the ground, and obviously a lot of casing and a lot of protection of the groundwater going vertically.

What about surface disturbances? Surface disturbance in some parts of urbanized America is a big deal, so pad drilling, using technology to start at the surface and then drill multiple wells from a single pad has become a big deal. It became a big deal in Pinedale, Wyoming because of critical wildlife habitat and the desire to minimize our impact on sagebrush that’s used by sage grouse, which are a potential endangered species, as well as mule deer and other critters that call this part of this country home. So we went to an application of pad drilling in Pinedale, Wyoming. Again, voluntarily back in the early 2000s where we put multiple pads – multiple wells on a single pad, up to 50 wells from a single surface pad. So if we drill these wells individually, we would disturb about two and half acres. By drilling multiple wells from a single pad, we have well pads with 50 wells on them that have less than 10 acres of total recovered disturbance. So a huge reduction in the footprint.

What does it look like? Well, on the upper left hand corner you can see where we set the surface casing, we excavate a hole, we fill that hole with a concrete box, you can see in the middle lower photo there the well casing and well heads being put on. And then once we drill the well, we frack it, we removing the drilling rig out of the way, on the right side is what our producing sites look like.

We put a grade over it because you can drive a truck over those wells safely. And fortunately in Wyoming, it's relatively dry so we don't create swimming pools. So this is an interesting point about best practices because what works here, doesn't necessarily work in Louisiana where this particular hole would be full of water and alligators and snakes before we could complete the well construction. But here in Wyoming where it's very dry, well heads below the surface and covered production facilities is the norm.

Besides drilling from pads, we also install liquid gathering systems to gather the flow back water, the produced natural gasoline that comes up with the natural gas. It eliminated all the tanker trucks that used to have to come out and visit the well sites. 165,000 tanker truck visits per year just on our operated northern third of the Pinedale anticline all goes away because of the piping systems we put in place.

We put tanks in place to capture the liquids in the system to basically gather all of the volatile organic compounds. We went in very early on and we put the best quality diesel engines on drilling rigs that we could find. Low emissions at the time was tier two, we're moving to tier three and tier four ultralow sulfur diesel, long before it was required by the EPA. We converted rigs to gas boilers for heat in the wintertime. And we brought – our company brought flareless completions or green completions to the Rockies in the early 2000s. Frankly, I will tell you in part because of the economic motive. Why burn something that you can sell? It's very simple, but it also had a huge impact on the emissions.

Our production systems, we spend a lot of time looking for ways to reduce emissions and this slide, I think, drives home the point. In '05 our volatile organic compounds, which includes fugitive methane were at a factor of about five compared to where they are today. And you can see the number of things we've done. I won't read those to you, but the key point is that this was all done voluntarily. It was done in an effort to minimize our impact on the air quality in the area where we were operating. Some of the volatile organic compounds are precursor chemicals to ozone and we have found in certain parts of the west, that ozone issues are a significant concern. We get ozone in Wyoming in the wintertime. You think of ozone as being a smog formation compound in urban areas in the summertime, but in the wintertime due to the snow and cloud cover and atmospheric conversions. So we've been focused on reducing to the maximum extent possible the emission of organic volatile compounds.

Finally, I got to talk about the benefits. Obviously, hydraulic fracturing and horizontal drilling ultimately result in the extraction of more hydrocarbons with less wells. And that's a very important point. It's been a very important point from the economics for our industry, but it also has a huge benefit environmentally from not only the overall impact of our activity, but also just a surface disturbance and impact on the communities in which we operate.

Finally, a couple of other key points. We talked about the – the last thing I talked about the economic benefits of domestic activity. I don't think it can be overlooked. The jobs that we've created in our industry, direct jobs, but also indirect jobs in the areas in which we're operating, states and counties in which we're operating. And of course the obvious benefit that other panelists have already raised about the lower carbon footprint of natural gas versus other forms of fossil fuels.

So with that, Jesse, I'll turn the floor back over. Sorry I went a little bit long.

Jesse Green: Thank you, Chuck.

Timothy Fitzgerald: Thank you very much. I live in a little town called Manhattan, Montana, which we affectionately refer to as "Little Apple," or the "Big Spud" depending on whether you like potato production. That's sort of another topic. But I'm happy to be here today and thanks to Dean Shizer and Tom Merrill and Mr. Green for getting me involved in this. I'm going to try to talk about the risks from an economist perspective a little bit. And try to think about who you are affects how you think about risks. What the risks are and how you perceive those risks. And so, Chuck just did a great job of talking about risks from the operator's side. In fact, I'm going to just try to hit the high points on that and leave you with his far more developed thoughts. And I'll – then I'll elaborate my thoughts a little bit as I talk about risks for people other than the developer or the operator. The operators' objectives are fairly transparent. They're trying to find hydrocarbons wherever they are. We've depleted a lot of the really rich conventional reservoirs over the course of time and now thanks to technology, we have the ability to access profitably the unconventional resources. But really from an operator's point of view, what they're trying to do is construct – they're making an investment in a well that they hope is going to pay back in terms of production over the course of time.

Earlier we heard about production and price as both being parts of revenue, which is obviously very important to a profit maximizer. The distinction I would make, and why I'm going to emphasis production a little bit is the price risk actually can be hedged a little bit. And a lot of producers do engage in various financial engineering types of transactions to minimize that price risk, but the geologic risk is still there.

As we talked about – non operators are talking about more heterogeneous group of people. We're talking about sometimes it's a royalty owner. We're talking about sometimes it's a – just a surface owner who doesn't own the mineral rights. You get a split state situation it may be someone who's downstream or in the next county over who's concerned about the impact. So I'm going to try to talk about two different types of impacts: subsurface impacts and surface impacts which are different in terms of their verification costs and I'll leave the air impacts and address pass for somebody else.

So if I were to try to characterize as a – the process of hydraulic fracturing, really starting with napalm fracks in the 1940s, and moving on through time to the very sophisticated fracturing that we see today where it is used in almost every well. It's implemented in some places with horizontal drilling and some places without, but the reason why hydraulic fracturing is so compelling is it's by far the cheapest way for an operator to touch a rock. If you're interested in producing oil and gas, you got to figure out a way to touch rocks below the surface. It's three to five powers of ten, so thousands to 100,000 times cheaper to do that with a fracture than with a well bore, whether that's a vertical well bore or horizontal well bore.

Now that's – that's a pretty compelling reason to keep trying this. I'm going to argue that we are a little better technically on the drilling side than we are on the fracturing side and there are a lot of improvements and investments being made in optimizing this technology. So the picture that you see on the left here is a bore hole profile. This is the kind of thing that a well site geologist would look at – or geosteerer would look at as they try to steer a horizontal well. This is actually from a Bakken well and they're going to go down vertically and turn and try to stay in the target formation. In this case it was a middle Bakken well, then the rig goes away and the fracturing crew shows up and then they try to think about where the fractures are going to go. They're going to use very impressive technology, that's microseismic technology, which is depicted in the image on the right and you can see the different stages in color and those are the echoes from the microseismic to give the engineers an idea of the extent and direction of those fractures.

But my argument is that the information from the microseismic is a bit courser and we're a little less certain about where exactly the fractures are. We have a pretty good idea, but we're not as sure about the conductivity. There's a lot of discussion about this in the petroleum engineering literature and what parts of the production process can be changed and optimized. So there's still a lot of room to optimize and improve the design of fracks and the design of wells.

So to give you an idea of how that might evolve just within one play, the Bakken gets a lot of press. It was first discovered in the 1950s with vertical wells that didn't work too well. In about 1990 there was some new interest in that field when they came back in and drilled some horizontal wells. It was still too expensive given how much of the formation you were able to access down hole. And so really it was in the early 2000s when you had multiple horizontal bore holes – multi-leg horizontal wells and what they call an open hole frack, which is – probably the easiest way to describe that would be take the water that Chuck was talking about, you dump it down the hole, you pump it up and the fractures go where they go. You don't necessarily know which direction they're going, but you're going to crack those rocks.

The results turned out to be quite good. They were free flowing wells with a light sweet grade of crude. This encouraged operators to come back and try to refine that technology going on the consensus in that field was to go to a liner or multi-stage frack, much like Chuck described. And with an increasing number of stages, up to 40 stages in some of these Bakken wells. Now that trend has backed off here just in the last couple of years as some operators have thought that perhaps fewer initial fractures that would reduce the cost upfront of a well. A typical completed Bakken well right now is running over $8 maybe $8.5 to $10.5 million depending on exactly what kind of completion is used and some of the operators are trying to reduce that upfront cost, but also with an eye towards maximizing the long term production with less interference between the stages.

So operators are used to making these decisions and I think Chuck actually did a great job of talking about the kind of construction decision concerns – what kind of casing should we use? How should cement it? What information does the operator want before they go ahead and complete the well about well bore integrity? And they use a lot of contractors, the service crews are highly specialized contractors, but they're also drilling specialists, well site geologists and operators are going to make decisions about how to balance the risks of another day with a rig that may be $25,000.00 a day, is that worth it so that we can bring a wire line crew in and check this well bore. Do our initial pressure tests warrant that expense or do we think we have a problem? So this is something that operators are very useful – or very used to operating in this sort of uncertain environment or risky environment.

Same is true with the completions as I described within the Bakken play. The designs are evolving. Both in terms of the fluid additives, in terms of the type of proppant whether it's natural or synthetic and the various sizes and the stages in the way that production actually takes place. And then, of course, after you've got the completion, then you've got production coming in. And then you've got more questions about how to deal with water management. I think across all unconventional plays we're seeing more and more recycling. That's true in the Marcellus, it's certainly true in the arid regions in the west where water is a little bit harder to come by and so it's a bit dearer and worth spending the money to try to figure out how to recycle it.

So let me just kind of segue to the second part of my presentation as I talk about – I think it's very important to kind of keep in mind that they're different types of non-operators. There are people who own minerals and there are people who don't. And if you want the simplest litmus test for people's views on the risks of hydraulic fracturing, it's whether or not they own minerals. If you're likely to get a check, it's some sort of weird discontinuous relative risk aversion. I'm not really sure. I'm sure there's some economic breakthroughs to be had.

I'm going to try to talk about the subsurface environmental risks and then the surface environmental risks. I think they're really two questions about subsurface environmental risks. Okay, one is are these toxic fluid additives from half a percent of the injected fluid going to end up in my ground water well? So that's one question and then a separate, but related question is well maybe I'll have hydrocarbons contaminate my ground water. And just to sort of motivate why I think this is a valid concern or this risk is real, I'd like to tell you guys a little bit about some work a couple of friends of mine have completed. They looked at Washington County, Pennsylvania, which is down in southwestern Pennsylvania. It's in the Marcellus and they looked at market transactions. I mean, I'm a coldhearted economist, as though there's any other kind, and I believe that the market's going to tell us what people actually do.

So they looked at five years of housing data and the interesting thing about Washington County is some of the houses – okay, there are all these houses that are being bought and sold – some of the houses have municipally supplied water, and other wells are on private – other are supplied water by private wells. So if you look at the proximity of gas wells to houses and we might think that the risks from hydraulic fracturing are fairly local. It's actually true that the houses that are closer to gas wells sell for more by about 10%. So there's actually a local benefit from development. This could be because they own the minerals or it could be because they're more rural parts of the county are more desirable to live in. But once you control for whether or not you're on municipal or well water, that positive price impact, which may be because new workers are moving in and demanding housing, but if you're on a private well, all of the sudden what was a positive housing price impact is now negative.

So add together 10.1 and 26 and you get negative 16%, so the market transactions tell us that the perception of risk is in subsurface ground water contamination. So I think there are three pertinent questions about the subsurface risks: what is the nature of that risk? Is it the fluid? Is it toxics or is it hydrocarbons, which are also toxic if you drink too much of it I guess. And the evidence that we have is that it's hydrocarbons, right. We found methane. We found methane from deeper strata; we're not entirely sure how it got there. Whether it got out through a crack in the well bore or – this is drawing on work that was published in the Nation Academy of Science a couple of years ago. The best example, and there's been a lot of press coverage particularly from people who are more concerned about the environmental impacts, right, that there was actually fracturing fluid in wells in Pavilion, Wyoming. Pavilion, Wyoming is very – has very different geology from the Bakken or the Pinedale anticline or the Marcellus. The distances are very much smaller. And despite a draft report last fall in which the E.P.A. said they had – well it was last spring, actually. Last fall they had to back away from the sort of smoking gun that they'd found in Pavilion and that is still very much up in the air whether or not we're going to find fracturing fluid. We haven't in a couple million wells yet definitively. Maybe that's because we don't know what to look for due to the trade secret type provisions.

To just talk about a couple of the other aspects of the subsurface risk, one is the special extent. So how big an area do we think the risks from one particular are affecting. Well, we have some evidence that that might be one and a half kilometers, which is fairly close. Now that may be on the same lease. It may be, particularly in the west where we have larger landholdings, right? We would think about that risk sort of being internal to the transaction between the operator and the mineral owner. In Pennsylvania perhaps or even other parts of the west, Rifle, Colorado comes to mind, where there's much fractionated holding of the surface, you got a lot more people within that affected emulous. And so you may have more people who have an interest in – a mineral interest in the well or not.

The verifiability is obviously a higher bar for subsurface risks, particularly with – I always laugh at the people who say that I can light my wells on fire. Well, they've certainly never been to southeastern Montana where that's not even a good party trick because everybody has methane in their wells because that's where the water comes from. It comes from the coal, and guess what, there's coal bed methane in that coal. But the baseline data is rather sparse and one of the things I get to do as an agricultural economist is talk to landowners before they sign leases. And I always encourage them to go ahead and get that baseline data.

Talk very quickly about the surface risk – the surface risk we already – a couple of speakers have already talked about what do we do with the flow back water and the produced water as it comes back to the surface. There's a recent study that's just about to come out again in the National Academy of Science Proceedings looking at the surface water quality in Pennsylvania over the time that the Marcellus has been developed, so some of that produced water – it is no longer, but it was being run through municipal waste water treatment plants. Downstream – in watersheds downstream from places where that produced water was being disposed they find significantly higher chlorine concentrations in the water, but no more sediment. And so the treatment plants are doing a good job of getting sediment out of the water, but not salt. In sort of a different measure of the impact, if there are more well pads upstream from you in your watershed, you have more sediment in the water, but not more chlorine. So you're getting runoff from the well pads. And those are very different kinds of effects on surface water quality.

The last thing I'll talk about is – Chuck did a great job of talking about Q.E.P.'s done with having a network – keeping trucks off the road, having an infrastructure network in place that carries produced water from the wells to a treatment facility. And that may be used for recycling. That really requires the pad drilling model to have the density that – for example in the Bakken right now we're using two sections, spacing units 1280 acre spacing units, most of those are held by one well. It's just not worth it to run a pipeline out to each one of those wells when you've got 50 wells on one pad, then it becomes much more economic. However, that allows you to recycle the water it contains. It keeps the trucks off the road, but you have a different kind of intrusion as you build that infrastructure in and the – I might just observe that one of the surface impacts that the non-operator often finds objectionable is the fact that they're – oh, they're going to put in another pipeline. It's just a change in the lifestyle that residents of areas with unconventional development have experienced. So there's a tradeoff there as you try to think about recycling more of the water and reducing the risk from produced water spill or something like that with a known intrusion.

So with that I'll turn it back.

Jesse Green: Thank you, Tim. Thank you.

Michael Levi: Excellent. Well, thank you to everyone's who's organized this. It's a fascinating day of discussions. I'm going to focus on climate change risks related to shale gas development. And I want to say a couple things upfront to be clear. I'm not focusing on climate change risks because I've decided that those are the greatest environmental risks that we should be thinking about when we look at shale gas development. If I had to pick, I would probably say – at least for the near term – waste water, air quality and community impact would top my list. But I do think it's important to think about climate change risks, both in the near term and the long term.

The second thing I'll say right at the top is that while I'm going to talk about risks on the climate side, there are very large benefits when it comes to dealing with climate change from the current abundance of natural gas and particularly unconventional gas in the United States. The chart up here, I unfortunately can't point to it, so I'm going to use a lot of colors in this discussion. The chart up here, the four bars on the left are a conventional view of what greenhouse gas emissions from coal fire power plants when you use coal to produce electricity. The middle five bars are a range of natural gas fire power plants. The higher bar on the far right is from a sort of older kind of power plant that isn't as efficient, but what you want to focus on are the four on the left. And what you see is that the estimated emissions from natural gas fire power are roughly half the emissions on a per unit of electricity bases than the emissions from the various coal fire power plants.

If you look at the breakdown in those bars, the green is the carbon dioxide that comes when you burn the fuel in the power plant. And the blue and orange at the bottom are the emissions entailed when you actually produce the fuel to put into that power plant. The blue the carbon dioxide, the orange is methane. And it's useful to keep this in line as a baseline because I'm going to talk a bit about how these estimates could change if some of our assumptions were different.

When I think about risks to climate change from natural gas development, I find it useful to put them into two categories. The first is the risk of higher greenhouse gas emissions than what's on this chart when you burn natural gas in a power plant and when you produce natural gas to put it in that power plant. And to me I think of these sort of as the micro-risks. These are the risks that when you use natural gas, it could be considerably worse than we think.

The second category is risks to overall energy system transformation. If we want to deal with climate we ultimately need to get to a much lower carbon system, even then what natural gas can offer and we should be asking does natural gas use pose any risks to that sort of transformation. I think of those sort of as the macro-system level risks.

Let's start with the micro category. The big risk here is the potential for a lot of methane leaking from natural gas systems. Okay, so on the previous slide I showed very large bars when you burn fuel in power plants, moderate bars when you produce it. The big wildcard there emissions of methane when you produce natural gas. Natural gas is mostly methane and methane is a potent greenhouse gas when it's released into the atmosphere. Our data on methane isn't particularly great. For the most part what we have is a lot of sampling of what happens when you use particular pieces of equipment in the field and particular processes in the field and we do surveys of what different companies and different operators are doing. We try to put this all together in what you would call a bottom up analysis to come to synthetic estimate of what's actually happening in terms of emissions.

In the last couple of years there have been two studies that have been enormously influential in trying to question the basic assumption embedded in the previous chart that methane emissions exist, but they're relatively small and pretty inconsequential. I'm always hesitant to talk about these two studies because it makes me feel occasionally like I'm going after straw men. But these are the dominant studies in the academic literature. They've driven the scientific discussion of methane emissions and the climate impact and they've driven the popular discussion. And that makes it essential to pay attention to them.

The first is reflected in a nice chart that some folks at Nature put together based on a study by a large team at NOAA that was published in the Journal of Geophysical Research about a year ago. If you look at the green bar that is a sort of conventional estimate from the bottom up based on the process that I was talking about of what methane emissions would look like. The other gigantic bars – that's the technical term that I use to describe them – are what the team estimated based on field observations. What's essential here is that this is the only study published in the academic literature where people instead of building from the bottom up, when out and looked at how much methane there was in the air around some of these operations and used that to try and infer how much methane was actually leaking from natural gas facilities. The big challenge here is that there are a lot of sources of methane, the background levels are uncertain and so when you do this sort of thing you need a sophisticated approach to taking your air observations and reverse engineering them to figure out what's actually happening with these wells.

And when you take a look at their inverse methods, they have some severe flaws. I don't want to go into all the fine details, but what I'll say they've been extensively debated, the chart at the bottom is from a paper that I wrote trying to go back, remove some of the assumptions from their analysis and use more data to try and constrain the estimates. If you look at the third form the right – I wish I could point to this – but the third from the right is the sort of bottom up estimate, which is in line with typical estimates from places like the E.P.A. The top right was the inference in the initial paper from this top down atmospheric observations. And the two estimates on the left are what you get if you reanalyze the air emissions observations that the team reported, but without using so many assumptions and while leveraging more data.

There's a second variable that can blow out the impact of methane emissions on climate change. And that is how you look at the impacts of methane over different time scales. So methane is a much more potent greenhouse gas molecule for molecule than carbon dioxide. Counteracting that is that methane does not stay in the atmosphere for as long carbon dioxide does. It actually transforms into carbon dioxide over time. So if you look at methane on a very short time scale, it traps a lot more heat per unit per molecule than carbon dioxide does. As you look over longer time scales, that discrepancy dies down. And what this chart is is a different way of looking at the first one I put up there. So let's just quickly flip back you saw these. These are all the blue lines in this plot. The red lines are what happened when you say, "Instead of focusing on the impact that happens over 100 years, I'm going to focus on the impact that happens over 20 years."

And that makes methane look a lot more influential and results in considerably higher emissions estimates and climate impact estimates than you have in the initial case.

The big question is which of these time scales should you be looking at. Or should you be looking at things in a third way? People will argue on the one hand that you should look at these short term views because climate change is an urgent problem, which is true and because there are risks of near term tipping points. I don't love the term tipping points, but I do think it's fair to talk about whether you might exceed thresholds in the relatively near term that would lead you to considerably worse climate impacts and inhibit your ability to really restrain emissions particularly from land systems of greenhouse gases.

The other view is that climate really evolves on long time scales. There's a lot of inertia in the climate system and so you really do need to think on 100 year time scales. I'll say something in a second about how I like to resolve it, but I want to flag this. This is the second prominent study by a team at Cornell. And what they do is combine very high estimates for methane leakage with a focus on a 20 year time horizon. What you find is when you make that combination, natural gas is actually worse for climate change than coal. Okay, so it really is important to nail down both the methane emissions and the time scale that you need at things over.

This one may be a bit tricky to read, but I think it emphasizes something important for how we should be looking at time scales here. If you look the lines on the bottom, what you'll see is that – just compare sort of the line at the bottom with the one that says 5% leakage. 5% is considered a high leakage rate in this business. And what you'll find if you look on a 20 year time scale, that leakage really bumps up the projected world temperature. Again, simple model. You can argue with it, but it really bumps up that impact. And that's that 20 year global warming potential that I had up there before doing its job. But if you're really worried about ultimate climate impact, what you care about, at least the first order is the impact on peek temperatures. We always talk about not wanting to exceed this, that or the other temperature threshold. And that's where you really want to be drilling down. And if you follow this chart out to the end – and this is one particular scenario where we do stabilized carbon dioxide concentrations – you'll find that by the time you're really looking at what determines peek temperatures, you are out toward the end of the century and you are appropriately focusing on that long term impact of carbon dioxide and methane. And this suggests that it's most useful to really be focusing on the long term impact.

Now let me give you a couple bottom lines before I move onto the system part. Leakage is real. There are cost effective ways to reduce it. I think we're going to learn a lot more in the near future. I hope Mark Brownstein will talk this afternoon a bit about what the Environmental Defense Fund is doing in this area. It is on a different plane from anything else being done – this study, these issues. It's really extraordinary. But we shouldn't let the discussion over methane paralyze us into not being able to make a conclusion on whether gas is better for climate change than coal. It is better for climate change than coal when it comes to the immediate emissions, but we do have opportunities to reduce those.

Now let me turn to the system part briefly because I think this is really essential. And while 90% of the public discussion about natural gas and climate focuses on whether methane severely undermines the value of gas, a lot more should be focusing on what abundant gas does to our ability to transform our energy system over time. What I've got here is results from a recent modeling exercise done by the Energy Information Administration at the U.S. Department of Energy. Again, the caveat ever model is unusual. It has all sorts of quirks and assumptions. So just pay attention the basic patterns here which I think fit with what makes intuitive sense.

All three lines on the top have one thing in common. There is not serious carbon policy in place. One of those lines is the sort of business as usual case. One assumes that natural gas resources are much smaller than they think they are. So this presence of abundant natural gas largely goes away over time. The third of those lines assumes that renewable energy is about 20% cheaper upfront than we currently believe it will be. Alternatively you can think of that as a scenario where government subsidizes renewable energy. And the striking thing you will notice is that greenhouse gas emissions, which are projected there are barely different in the different cases, okay?

So compare that to the two bottom lines. And what the two bottom lines have in common is that there's a carbon policy. And what you'll see is that for the next decade or so the various lines with the same fairly ambitious carbon policy have a similar trajectory, but beyond that the one with abundant natural gas doesn't do as well in terms of emission. So I take two lessons from this. The first is that if we want to focus on the long term trajectory of our energy system, we would be doing better to look at our carbon policy than at how abundant natural is, but that as we get further out, abundant natural gas can pose some challenges to energy system transformation.

I do want to give one slightly different way of looking at this. In the projections I just gave you, there are assumptions about how technology cost develop over time. And those assumptions are consistent across the different cases. That may not be the right way to look at things. When you deploy a new energy source, you get opportunities to cut its costs. You can build economies of scale, you can learn. You can learn on the technology side, but you can also learn manufacturing, installation, financing. And if natural gas deters deployment of emerging technologies in the near term, then it could get in the way of opportunities to cut costs, which over time could have bigger impacts on the energy system.

And what I've got here is a plot for solar photovoltaic. Again, don't believe the exact numbers. Look at the basic trends. And what you see is a projection that if we cut natural resources and pushed our prices we could get more solar photovoltaic development, which means we would bring down costs more. But if we went to that purple curve, which is basically a case where you put in supportive policy, we would get even larger gains in solar p.v. deployment and presumably in innovation and cost reductions as a result.

So to me the lesson of this chart is that natural gas does create some risks for technology development. We need to mitigate those. But that support of policy is a much larger factor in determining whether we will have the low cost zero carbon options that we need.

Let me sum up by emphasizing, again, three bottom lines. First it's essential that we think about these micro and macro risks at the same time. That we not let one distract from the other. The second is that micro risk, the risk associated with methane leakage have often been overstated. They're still important, but they shouldn't blind us to the fact that natural gas is better for climate change than coal. And the third is that over time the macro risks have the potential to be considerably larger and deserve a lot more attention. Certainly proportionally than I think an absolute terms than they've received so far.

Thank you all for your attention.

Jesse Green: Thank you, Michael. Okay. Let me start with the questions and I'm going to go a little bit into the lunch in 15 minutes here, so that we can cover some of these questions.

The first one's a simple one, but I think it's an important one we really haven't addressed. What happens to a well after its 40 year life? And I'll add to that, is there any remedial action that needs to be taken on the well at the end of that time?

Charles Stanley: Great question. Many wells last longer than 40 years. In fact I think one of the oldest gas wells in the country is in upstate New York, ironically, around Fredonia. It's been producing for close to 100 years. Still going strong. Well, going very weakly, but producing gas. At the end of the economic life of a well, yes there is remedial action that's needed. The well is plugged with cement and the surface equipment is removed and then we do a remediation on the disturbance. Reseed the area, replant trees, etc. And I can take you to places where I would challenge you to find the surface impact or any evidence that there was ever oil and gas production. And those are in places like Wyoming where things don't grow very fast. So in places in the eastern U.S., if you go into the old historic producing areas in Pennsylvania, very little sign that there was ever any oil and gas activity there.

But, yes, there is remedial action necessary. It's required under the regulatory regime in all the states that the wells be properly abandoned and so they are put to bed or put to rest if you will very methodically.

Jesse Green: Thank you. Thank you. Different one here. Which is more dangerous: methane as a trapped greenhouse gas released into the atmosphere or methane used as an alternative source of energy? Tim or Michael?

Michael Levy: I'm happy to take that on.

Jesse Green: Go ahead.

Michael Levi: Can you guys hear me now?

Jesse Green: Yes.

Michael Levi: Methane trapped in the ground. Methane as an alternative source of energy is allowing us to reduce greenhouse gas emissions now. If we did not have this abundance of methane, we would be using a lot more coal than we currently are. And over time, regardless of whether we have abundant methane or not, we're going to need to adopt serious policies in order to reduce our emissions. We are not going to be saved by geological scarcity from the need to think seriously and act seriously on climate policy.

But methane in the ground is a problem. Particularly when we're talking about methane trapped in the permafrost. Because as we get to higher temperatures, the permafrost thaws, you get more methane release, it heats the atmosphere, that heating thaws more permafrost and does all sorts of other things that we don't like to see happen and you get the cycle. Now I don't think we understand it particularly well. We don't know the pace at which methane – at which permafrost melts at different temperatures. We don't know how differs by different geographies. But that has the potential to release very large amounts of methane into the atmosphere and to take things essentially out of our control once we're past a certain point and let them run away.

With natural gasses in the ground that we're deciding whether or not to develop, at some level it's always going to be within our control.

Jesse Green: Thank you. Thank you, Michael. Chuck this is for you. In the context of recycling frack water, how does the level radioactive contamination change over time and reuse and what measures can be taken to protect well workers from this water and ensure its safe and ultimate disposal?

Charles Stanley: Radioactivity in flow back water – in produced water over time, very, very small. There's been some studies done. I think there were a number of articles that appeared in publications early on about concerns over radioactivity in produced water associated with shales. Organic material in the shale is a – creates radioactive character of the shales and actually some radioactive minerals associated with the organic material. Remember these shales outcrop all over the place, especially in the Appalachians, the same Marcellus shale that we are drilling into completing and producing gas from, is widespread at the surface over huge areas if you look at a geologic map of the Appalachian region, the Devonian shales are the primary outcropping rock. So I think that there's a misplaced concern about radioactivity. Recycling water doesn't materially change it. The shales, in fact, as one of the earlier panelist pointed out, tend to keep a lot of the frack water incorporated in their structure – in the clay structure, so for us it is not a large concern.

Jesse Green: Okay. Thank you, Chuck. A couple here on methane and methane hydrates. First one, what is your understanding of methane residence time in water and air? And of course what's the implication on the pollution aspects of this?

Charles Stanley: That's your guy's question.

Michael Levi: It's only a climate question once it gets out. To be absolutely blunt about it, that really is true. The methane emissions that we worry about are ones that don't – that come out of – not just well equipment and drilling equipment, but particularly things like pipelines and local distribution systems. I mean, that's – again, I don't want to predict what the E.D.F. study will say, but I expect that that will be one of the headlines is that we're not losing in something specific to shale gas, as much as in the broader, natural gas system. Methane residence time the atmosphere in the half life is something like 12 years, but I may have that wrong. Someone can correct me.

Charles Stanley: That's about right.

Michael Levi: As far as it migrating through water, that's your guy's territory.

Charles Stanley I'll take this on because I think the system's leakage questions are very interesting. Absolutely there is leakage. I agree with Michael. I think that estimating the quantum of leakage is much more difficult. And I'll tell you from the producer perspective that we do everything possible. Of course, our primary business is producing the stuff to sell, not lose it to the atmosphere, so we spend a lot of time looking for opportunities to reduce fugitive admissions. I talked about some of the systems that we put in place in our producing fields. We have gas detectors. We go around looking for leaks, either with fleer cameras or with just sniffers to look for methane leaking from valves and from various connections in our gather systems and piping. As you move away from the well head and the gas transmission systems, there has been a lot of numbers published, which I question because there's still an amazing inaccuracy in the measurement and metering of natural gas at the well head versus when it's put into an interstate pipeline, when it's introduced into a local distribution system and then reticulated to individual houses and businesses.

And the cumulative measurement error some mistake for losses. In fact, pipeline companies and distribution companies have a line item called lost and unaccounted for, which in many instances is not leakage, it's mis-measurement. And measurement technology is still a – a 1800s orifice meter where you make a calculation about pressure drop and that gets you to a quantity. So the technology that we use in the field, because we're very interested in getting paid for everything we produce, we're using ultrasonic meters that can very accurately measure the flow of gas through the measurement systems. But downstream of that point, the measurement errors I think are confusing us. Now, in other parts of the world – other pipeline systems, especially in former Soviet Union and other parts of the world where care of construction of the piping systems has not been as great. And even in some areas in the U.S. with very, very old, some of the original gas distribution systems that were built, not to distribute gas from shale beds or from gas wells, but from actually warming up coal and driving methane off of it.

Some of these systems that – the local distribution companies around the country have been doing a lot of work to replace old cast iron piping with modern leak free piping systems. So I think there's still opportunity. I don't know how huge it is. I think that there's certainly a way to reduce fugitive emissions systems, but the math escapes me on some of it because I think a lot of it is confusing measurement errors with leaks.

Michael Levi: Can I pick up very briefly? So that's why – that's a big reason why I think some of the new work is really exciting because it's combining these broad observations with a bottom up look. What they'll do is they'll go out in the field, they'll say, "Well, that looks there's a lot of emissions happening. They seem to be concentrated in these places."

And then they'll actually get cooperation from the operators and go and say, "Okay, is it bleeding from this. Is it coming out of that?"

And you have to put those two pieces together to figure out whether it's a statistical issue, or whether it's a real – a real thing.

The second is that a lot of anecdotal evidence suggests that these emissions are dominated by the tails of the distribution. And so that means that even if you're doing a half decent job of sampling what's out there, you can be missing some important things.

The third you point to the former Soviet Union. Super important. The most alarming study that was – that's been published on methane actually used Soviet Union data to estimate what was happening in the United States. Not the best way to go about things, but if we're talking about globalizing what's happening in the United States, absolutely essential to keep in mind.

Jesse Green: Thank you. Last question I'm going to take so we have adequate time for lunch. As it pertains to fracking risks, can you comment on the potential or lack thereof, for methane hydrates to play a role in the coming decades? If methane hydrates come to pass, hydraulic fracturing could become a mere footnote. The regulatory and security issues could be significant.

Michael Levi: I have a thought on that one.

Charles Stanley: As a geologist, I'll start. Yeah, methane hydrates are widespread. They occur on the – immediately below the seafloor and a lot places around the world. Under the permafrost in Alaska and other artic regions. Been identified for 100 plus years as a potential source of energy. The problem is they're disseminated. They are – they're an unstable form of basically frozen methane. And how you can collect them, concentrate them and control their use is – has been a challenge. I know many countries, in fact the Japanese who are a large importer of natural gas because they lack a significant domestic supply, has spent billions of dollars researching methane hydrates looking for opportunities to commercialize them. It's a huge technical challenge, but just as I would have said maybe 10 or 12 years ago that we wouldn't be sitting here talking about the abundance of domestic crude oil or domestic natural gas, there are a lot of very smart women and men around the world looking at methane hydrates as potential energy source. And I would not say the problem is insolvable. It's very challenging, but it may not be insolvable.

Michael Levi: So there's a fascinating article in the new issue of the Atlantic Monthly out in about a week about this. And what's kind of interesting is that the writer reports that a dozen years ago or so he went out to some strange people in Texas who were doing something with this horizontal drilling and hydraulic fracturing and said they were going to develop a lot of gas and he had this great scoop. And then everyone he talked to told him it wasn't going to happen. He didn't write it.

And so he is compensating for that this time around by writing this breathless piece about methane hydrates after the recent discoveries in Japan. I just give one warning on that and then one broader observation. One of the things that has allowed development of shale gas to move ahead so quickly is the fact that you can cycle through innovations rapidly. So these wells aren't that expensive to drill. You drill a lot of them, there's a lot of learning that goes on throughout this sort of industrial ecosystem. And that allows you to improve quickly. These methane hydrates projects are big. They are expensive. They are government controlled. They take a lot of time and then you take time to produce results. That doesn't lead to the kind of rapid innovation that you've seen in this area. Just forget about people's attitudes and the technology itself, just the time scales are different. So it could be more like nuclear energy, which had very slow and possibly sort of negative cost reduction feedbacks. So there's just this very different characteristics of the technology that could lead to a very different development path.

But more broadly this brings us back on the climate front to importance of policy. Whether we have a ton of methane hydrates out there or we don't, we are not going to be saved by geology from needing to actually do things about climate change.

Jesse Green: All right. That concludes the risk panel session. Thank you to my panel.

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Duration: 70 minutes