SOUTH CENTRAL ALASKA ENERGY FORUM

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Egan Convention Center

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P R O C E E D I N G S

(On record - 8:00 a.m.)

CHAIRMAN NORMAN: Good morning, folks. Welcome to the second phase of the South Central Energy Forum. We'll go ahead and start. We've got a couple of very interesting speakers to lead off and they'll be introduced by Commissioner Dan Seamount.

I was asked yesterday to make an announcement and one that I didn't get to and that is if any of the speakers or presenters left memory sticks be sure to pick them up. They're over there with the IT folks.

Commissioner Seamount.

COMMISSIONER SEAMOUNT: Okay. If any of you haven't realized it all the material that was on the table yesterday is to your left. If you want to pick it up that would include the agenda.

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CAROLYN DUNMIRE

COMMISSIONER SEAMOUNT: Okay. Our first speaker is Carolyn Dunmire. She is the managing director of Dunmire Consulting and she is the lead author of the Cook Inlet Energy Alternatives Study which is after reading it, is a very complete and excellent report. I think you all should read it. In this study she evaluated over 20 different supply and demand alternatives for providing energy to the Cook Inlet region. She also conducted a similar analysis on renewable energy alternatives for the villages in Lake and Peninsula Borough. So let's welcome Carolyn Dunmire.

MS. DUNMIRE: Good morning, welcome to the second day of the forum. And I think it's going to look a little bit different today which, I think, is good. Yesterday we saw a lot of charts with cliffs and gaps and, perhaps, shortages and today is going to be more of a discussion about solutions. How to fill those gaps, options and alternatives for avoiding falling off the cliff. So I can assure you that in my presentation there aren't area charts and it looks like even in the next one, too, so there's going to be some new material today so I hope you're looking forward to that.

I'm going to be talking about the Cook Inlet Energy Alternative Study. This was commissioned by ANGDA, the Alaska Natural Gas Development Authority. Harold Heinze and the board asked us to look at alternative energy solutions for Cook

Inlet.

I'm going to show some of the study results and the study conclusions. And the best way -- I tried to pack a lot of information into these slides so the best way to follow along is with the paper version that's over on the table there so if you don't have one of those in front of you, you may want to get one because you're going to be cursing me about the size of the print.

I also want to thank the Commissioners for not only inviting me to speak today, but also bringing me up here. I'm from Colorado and they helped pay my expenses to be here today, so I really appreciate that.

Just a little bit about the Dunmire Consulting team. I'm the lead author. I have 20 years experience in the energy industry and did a similar study for Lake and Peninsula Borough on energy alternatives for village power, specifically renewal alternatives.

Other members of the team include Integral North America here in Anchorage. Charlie Sassara, one of the team members is here today. And they did some key surveys of stakeholders to help us shape the criterion and the presentation of our results.

And then also we included Cronshaw Consulting, Mark Cronshaw, who added a very unique perspective. He worked on the pipeline, gas pipeline economics 20 years ago and so he

brought a unique perspective on looking at the gas pipeline alternatives today.

What the ANGDA Board and Harold Heinze asked us to do is to identify and quantify the major energy sources in Cook Inlet. What's here now. And then look at -- identify energy alternatives and quantify things like on line date, capital investment and other parts and then compare the alternatives. What they didn't ask us to do was find the answer.

What we did is looked at and compared the alternatives. We did not say this is the way to go. So we looked at -- we reviewed probably about 20 to 25 different options and ranked or compared about 18 -- no, 17 different alternatives and we divided an alternative into two groups.

First of all, an alternative is any sort of action program project that would bring supply to Cook Inlet, energy service or supply to Cook Inlet. And we compared them in terms of natural gas billion cubic feet and I'll explain a little bit more about that later.

We divided the alternatives into two groups, supply alternatives and demand alternatives. Supply alternatives are those alternatives that use the existing natural gas infrastructure, the transmission and the delivery system that exist in Cook Inlet. So it includes things like increasing production, the different pipeline, natural gas pipeline routes to bring North Slope gas to Cook Inlet, coal bed methane,

importing liquefied natural gas, and developing gas in other basins such as Bristol Bay, Nenana or Copper River.

The other thing on this list is coal gasification and that's kind of a little different. Coal gas isn't necessarily the same thing as natural gas, but as a gas it could use that existing infrastructure, so it's included as a supply alternative. We can talk about where it belongs at another time.

The demand alternatives look at either reducing or substituting for natural gas. And the way this works is you heard yesterday about two-thirds of the electric power generated for the Rail belt or for Cook Inlet is generated using natural gas as the fuel. So if you can use another fuel or reduce electric demand somehow that will by substitution reduce natural gas demand.

So we looked at coal, hydro, wind, nuclear, tidal, gas conservation and electric conversation. If you use less electricity you, therefore, use less gas. Distributed generation and geothermal power. It looks like it got a little messed up on the print-out. So we looked at about nine different alternatives here.

And if you've seen this presentation before we've now added geothermal and kind of updated some of the other options so you can stay awake for the end of this thing, too, 'cause it has changed a little bit.

Then we looked at the evaluation. You know, how did we evaluate the different alternatives. We came up with eight different evaluation criteria. And I'll go through each one as we go through the results. The idea here is to look at each of the alternatives and we rank them according to the criteria.

And then you, personally, or as other decision makers can then say well, to me the most important criteria is, for example, energy service. It has to bring at least 100 Bcf worth of gas to the region and I won't consider anything that does not do that. Well, you can then rank energy service as your highest criterion.

So this is the way -- the way this study is put together is that you can then rank the alternatives depending on what criterion is most important to you. So let's look at the different criterion and the way we evaluate them.

The first one is energy service. And the way we defined energy service is how much energy can this project plan resource bring to Cook Inlet and we did it in terms of billion cubic feet per year. Remember from yesterday Cook Inlet area uses about 200 to 220 billion cubic feet per year of natural gas.

So the top alternatives, those with the biggest flame rise to the top of the list. Supply about a 100 to -- or higher billion cubic feet per year. The ones in the middle supply anywhere from five to about 100 and then the ones at the

bottom supply less than five billion cubic feet per year.

Now, we need to talk a little bit about how this -- how we defined or scaled the alternatives. When we define an alternative we looked at not just, you know, how much hydro can we possibly build in Cook Inlet. We looked at what is most likely scale of hydro and number of projects to be built in, say, the next 20 years.

So we eliminated things like Susitna hydro partially because something at that scale, like, 1000 megawatts is just too big and very unlikely to be built because of the amount of capital and the potential environmental impacts associated with it. What's more likely to be built in the next 20 years is, say, five to 10 smaller hydro projects so that's the alternative we looked at here.

On the other end we eliminated some of the really small things, say for example, wind diesel hybrid system. Now, those are being very successfully implemented in village power, but the economics of those systems don't work in some place like Cook Inlet was -- when you've got an electric grid. So that's kind of how we define the alternatives.

So some of the things that have rather small energy service like nuclear power that's kind of surprising. Nuclear power usually is implemented on a rather large scale and actually what they're looking at for Alaska is this new, simple, safe, small -- you know, I forgot, four S reactor for

Galena and that's about a -- I think a five megawatt -- 50 megawatt nuclear generations so that's a new scale for nuclear generation that's being tested or proposed to be tested here in Alaska.

So -- and one other note on the -- kind of the ranking of things, while they're kind of ranked in order here by size you kind of see that they're grouped by big flame, middle flame and little flame. Within that group things could kind of move around up or down within that group. We're just kind of giving you an idea of is it either the top of the list the middle of the list or the bottom of the list. So that's energy service.

Prerequisites for success, these are the hurdles that the alternative has to clear before it will provide the energy service to the region. The alternatives with the lowest hurdles to clear are at the top of the list. So things like gas conservation, increasing production, those are kind of happening already because of the higher gas prices that we're seeing so that's encouraging things like natural gas conservation, turning your thermostat down so that those things are already happening.

The classic example of this is the spur line. You can't have energy service in Cook Inlet until there is gas flowing through the main line at least to the takeoff point for the spur line. So prerequisite for the spur line is that there's gas flowing in a main line to the takeoff point, so

that's what a prerequisite for success is.

Start-up date, fairly self-explanatory. Things with the earliest start-up date are at the top of the list. Something 15 years out is at the bottom of the list.

And the reason why things might be near the bottom of the list, for example, tidal power is that there's really only demonstration scale projects being implemented in the world right now and there has yet to be a demonstration done here in Alaska and so there's still just too many questions that need to be answered and covered before a commercial scale tidal power project will happen so we're expecting that to be out near, say, 2015.

Capital investment, this is the amount of money you've got to raise to make this thing happen. So the alternatives with the lower amount of capital investment requirements are near the top, the ones with higher amounts are at the bottom.

Hydro power surprisingly is near the top mostly because we're talking about smaller scale hydro projects. Hydro is generally fairly capital intensive. Things like distributed generation, again, because they're a smaller scale you don't have to raise as much money.

Conservation are usually a little bit smaller as far as capital investment, but usually you have to invest something as far as people buying light bulbs, improving furnaces and appliances, that kind of thing.

Monthly bill, this looks at the effect on utility bills for customers so while capital investment looks at the one time amount of money you have to raise, a monthly bill looks at what is the annual cost associated with this thing and including debt service. And the things that have the lowest impact on utility bills are at the top. The alternatives that might double utilities bills are at the bottom.

So, again, conservation rises to the top because it actually can reduce total monthly bills for people. And then the cheaper electric power options, coal, geothermal, wind, hydro are in the middle and then the more expensive capital, move expensive options, things like importing LNG move to the bottom because you've got to buy imported fuel.

Uncertainty, and this has to do not with risk, but uncertainty. We're talking about here what are the uncertainties on whether the alternative will bring the amount of energy service on the start-up date for the capital cost that we estimate here. How certain are we about those things happening.

And so the things with the least amount of uncertainty move to the top so conservation moves up because we have a pretty good idea -- there have been now some -- I learned yesterday there's been some calculations of elasticity so if you raise the price of gas a certain amount clearly people reduce the amount of gas that they use and there's some

estimations of that now, but there are questions about will that persist if gas prices were to drop, would people continue using less or would they go back to their old demand levels.

Hydro power, coal power, wind power, those are things that have been fairly well demonstrated. There's commercial operation throughout the U.S. and the world that we can look to and say this is what it takes to put together a coal project.

Things like tidal power, small scale nuclear power fall to the bottom of the list. And then, you know, coal bed methane, other Alaska gas we really don't know what the amount of economically recoverable gas is there. There just still needs to be more exploration work done and so there is quite a bit of uncertainty about what those resources are so they fall to the bottom of the list.

Key word here is unmitigated environmental impacts, not total environmental impacts. We're assuming that any project that is built or alternative that is implemented will meet or exceed environmental regulations or requirements so these are things that are unmitigated meaning that there isn't anything done to -- there just can't be anything done to help that problem.

So the things with the smallest amount or fewest unmitigated environmental impacts move to the top. Conservation appears up there, distributed power. And then alternatives that have potentially large unmitigated

environmental impacts move to the bottom.

One impact that I think is really interesting and Harold Heinze pointed this out to me is related to the pipelines. If you look at the picture up there is that a positive or a negative. When you've got a right-of-way for a pipeline it could be one or the other. Some people may view that as a positive impact and I've spent my time in Bush Alaska, pipeline right-of-ways are a great thoroughfare. You can get through on your four-wheeler, you can walk, use your snow machine and it's a great way to get around.

On the negative side that great way to get around is now access to what was pristine land. And so the right-of-way access becomes either a positive or a negative impact depending on your perspective and so even though it is an unmitigated environmental impact, it's not clear whether it's positive or negative.

Alaskan citizens, this is -- talk about being in the headlines here it is, it's the impact on Alaskan citizens as measured by things like the dividend check. What impact will it have on the Alaskan economy, employment, as well as state resources and revenues. And so things that have the most potential for new jobs increasing state revenue move to the top. There's the pipeline projects. And the things that use either imported technologies or imported fuels fall to the bottom.

And people are often surprised to see things like gas conservation, electric conservation, nuclear -- well, not so nuclear, but wind power at the bottom and that's because these are imported technologies. You're going to have to go outside to bring in the light bulbs, the wind turbines. All of that technology and equipment will come in from outside because it's not manufactured here in Alaska and so those dollars and investment dollars will go out of the state so that's considered a negative impact from this perspective for Alaska's citizens.

So putting it all together what do we get. These aren't the answers, but they're some ideas and trends that we're seeing. The top alternatives, things that sort of hung near the top are gas conservation and increased production. What they would do in the near term is buy time. It would prolong the existing supplies that we know about, to buy time to raise capital, implement demonstration projects, try new things.

Intermediate term, coal gasification looks pretty good and I learned more yesterday with Tim Johnson here on the Blue Sky Project that the technology is even looking better. There are some new coal gasification projects going in throughout the world using the lower heating value, low rank coals like Alaska has and they're proving to be quite successful, so coal gasification is looking quite promising.

And that brings the option of using the existing gas infrastructure and keeping facilities like Agrium on line and Agrium then would generate power which would help with the power shortage as well.

Long term, looking at the pipeline alternatives from these perspectives the enriched gas line looks a bit better than the Bullet Line mostly because it just brings more energy. It brings some liquids as well as natural gas to the area.

Coal, wind and hydro deserve equal consideration. There's been a lot of research and time spent on the pipeline projects. Coal, wind and hydro deserve equal time. They show equal promise and Alaska has the resource to implement these options. They deserve consideration.

Geothermal and tidal are two things that I sort of overlooked before, but there has been some recent projects, namely, Chena Hot Springs has started a geothermal project just last month and that's looking really promising. It uses a new low temperature technology and that looks like it could be implemented in a lot of places throughout the state.

And tidal power, there's recently been a feasibility study done for Knik Arm near the bridge that's proposed across Knik Arm and that has just sort of filled in some of the question marks about what the potential for tidal is here as well as what the costs are.

And, finally, the spur line tops the list, if the

pipeline carrying North Slope gas comes through Alaska the spur line is at the top. It brings the most gas -- most energy service for the least amount of money and most reliably, but there's that big if about the main line pipeline.

So this could be Cook Inlet's energy future. You know, we're looking at things like hydro, wind, that there's some bio mass turbines there, as well as the Clean Coal Project at Healy and that's the Chena Hot Springs project.

So we don't have time for questions this morning, but I will be here all day and I would appreciate your questions, comments, any additional information that you have. The full study is available at ANGDA's web site there and you can contact me by e-mail at that address. Thank you.

COMMISSIONER SEAMOUNT: Thank you, Carolyn, that was very informative.

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MARY ANN PEASE and CHUCK LOGSDON

COMMISSIONER SEAMOUNT: Our next speakers are Mary Ann Pease and Chuck Logsdon. Mary Ann Pease is currently working for the Governor as a gas pipeline advisor. The focus of her efforts will be on a comprehensive communications strategy with special emphasis on the community and business outreach portion.

Prior to her position as a gas pipeline advisor to the Governor, Pease was vice president, corporate communications at Alaska Communications Systems. At ACS, Pease was responsible for the company's corporate communications strategy to include investor relations and regulatory and legislative strategies at the state and federal levels.

Before joining ACS, Pease served as vice president of Aurora Power Resources, Incorporated where she developed strategies relative to bringing competition to the power industry.

Ms. Pease has an undergraduate degree in Economics and a Masters Degree in Finance. She served in progressively responsible positions during a seven year tenure with the Municipality of Anchorage, including more than four years as chief fiscal officer for Municipal Light & Power.

In addition to Chairman of the Board for the Anchorage Chamber of Commerce, Pease serves as a national board member for AEDC, board member for Commonwealth North, Executive

Committee, and board member for the Alaska State Chamber and is a member of ATHENA. She is also president of Alaska Children's Services.

Chuck Logsdon is a Matanuska Valley resident and graduated from Palmer High School in 1967. He has a Ph.D. from Washington State University and was the former chief petroleum economist for the State of Alaska and has more than 25 years experience in petroleum economics. He has been working for the last year for the Governor's Office as a spokesman for the gas pipeline negotiations.

Please welcome Mary Ann and Chuck.

MS. PEASE: Well, good morning, everyone. And that did say I was Chairman of the Anchorage Chamber and that was true, but that is an elective position and that chairmanship role changes each and ever September so we have a new Chamber chairman in Bill Evans, and he is going to be doing the September through September term that started just a few weeks ago.

I'd also like to note in the audience is president of the Anchorage Chamber, Stacy Schubert. Stacy, why don't you stand up there so everyone knows who you are. Thank you, Stacy.

This year the Anchorage Chamber among many things that we undertook as key policy initiatives was a review of natural gas in Alaska's future.

And I'd like to mention briefly that these white papers that were developed are extremely extensive, comprehensive and very, very informative. They talk about the facts, they talk about priorities for a natural gas pipeline and they even discuss which route is the most viable. So they're available on the Anchorage Chamber web site and I think Stacy also has some copies in the back that you are welcome to if you so desire.

Now, moving on to the presentation today and we'll see how this works. Oh, it works quite well. You know, it's nice to start at the 50,000 foot level and look at Alaska gas and our basin structure here. You know, there's a reason why Alaska is so incredibly attractive to investment and it's shown right on this chart. Lots of opportunity. Granted much of the oil and gas exploration have taken place in two regions, both at Prudhoe Bay and also the Cook Inlet and, you know, there's a simple reason for that, oil and gas were discovered early on and the infrastructure is in place.

I truly believe that the opportunity for Alaska will be severely curtailed with this chart even here if we have a reserves tax on the November ballot. I believe the impact.....

UNIDENTIFIED VOICE: No politics, please.

MS. PEASE: I believe that the impact on oil and gas exploration would extremely take a negative turn because of the impact on investments going forward.

If you look at this next slide it is an iceberg and as most icebergs this is only a representation. The very top part is the proven reserves in Prudhoe Bay and Point Thompson of 33 trillion cubic feet. And what you see underneath there, the part that's always hidden under the water is what we call the technical resource base with over 2035 trillion cubic feet and over 529 trillion cubic feet of gas hydrates.

Now, the issue with gas hydrates is, of course, that those have not been technically proven on how you remove them. The technology doesn't exist today, but going forward in time I think there's another, you know, incredible opportunity there.

These estimates are based on the Department of Natural Resources and if you look at the total current U.S. consumption, trying to put all of this stuff in perspective, we're about at 22 trillion cubic feet per year.

Now, zeroing down and coming into the more centric portion of where the resources are if you look at Cook Inlet with about 1.6 -- you know, I'm not moving this forward. If you look at Cook Inlet with about 1.6 trillion cubic feet of proven reserves, there is an additional potential there of 13 to 17 trillion feet. Bristol Bay and the Alaska Peninsula about 23 potentially. And the Chukchi Sea potentially 60 plus trillion cubic feet.

There's plenty of other non-conventional gas that people have already mentioned and could take the form of

hydrates, coal bed methane, shallow gas, tight gas, et cetera.

Now, this next chart here is truly a starting point and what you see here is the mainline. I believe that's the first step. It takes the gas off of the North Slope, comes down through out state with the offtake points, those squares. I don't know if you can see them or not, but -- well, I don't want to laser Chuck or anyone else in my view here, but the offtake points are the squares that you see there and the various spur line options that truly would be a very viable source for bringing gas to South Central.

This chart, I think, is one of the most important charts in our presentation today. It looks at the historical and projected crude oil and the natural gas production. And if you look at the oil production curve without any gas, it is in steep decline. And if you look at where we'll be by the year 2030 I certainly wouldn't want to be balancing the state budget under this scenario.

What is desperately needed is that pie, that additional increment that could come in from the natural gas production. Those needed new reserves. And, hopefully, with that additional gas exploration you'll also have additional oil that will be discovered that will help fill that gas that you see in this chart here.

So, you know, it was very nice last night when the Permanent Fund dividend was announced and I know people are

excited about the numbers, but I truly believe that scenario going forward would be dramatically different if we didn't have the additional natural resources filling that. And from a non-political standpoint, the reserves tax truly would definitely impact this chart because I do not think you would see that additional gas exploration and additional oil exploration going forward.

UNIDENTIFIED VOICE: There's nothing to substantiate that.

MS. PEASE: There are numerous benefits associated with the gas pipeline. The state revenues, the growth and sustainability in the oil and gas industry and also the private investment and growth opportunities. Job opportunities, stability, growth. A very positive picture going forward.

Now, under various scenarios, does anyone know what gas closed at yesterday? The October contract was under $5. Oil under 60. When Chuck and I were giving this presentation a few months ago oil was in the $70 range and gas was well over six. So the numbers change, but as you can see the state income if you look at it over a 30 year period is still very positive.

That break even point that we're looking at here was around 3.50 and that was with, you know, a return as well to the state. So state income if we're at about that $5 range would be somewhere between 60 and $70 billion over that 30 year

period, pretty substantial.

You know, the total state general fund budget runs around three, three and a half billion dollars and the state revenue that is projected from the gas pipeline would be about two to three billion a year for the next 30 years.

So when you put it in context with that total picture it certainly does give us some hope for what the future holds if you look at that new revenue coming in rather than reverting back to that chart that showed the oil production decline that is so much a concern on the TAPS Pipeline. And, you know, no one wants to be a one trick pony with just oil, so it certainly would be nice to get that double bang on both oil and gas.

State revenue for public policy, I believe quality education is extremely important to the future of our state. Economic development in communities, revenue for communities, whether it take the form of municipal assistance and state revenue sharing and also safe communities, well maintained roads, infrastructure development, everything that oil and gas revenues have played a very pivotal part in, in years past.

And, of course, 25 percent of all of the revenues from the gas pipeline would go into the Permanent Fund and some of the estimates are that there would be at least an additional 10 billion deposited over time into the Permanent Fund.

And, finally, jobs for Alaskans. Many of the internal reports projected 9,300 additional jobs. And, hopefully, with

the job training opportunities that have been so much at the forefront this last year, those jobs could stay here in Alaska rather then so much of the imported labor that we've seen before.

And then, finally, the segue into Chuck's presentation is truly gas for Alaskans. The most critical component of any gas pipeline project. I know Harold Heinz's organization and many others, the Anchorage Chamber also identified this, it's fine if we have a gas pipeline, but there has to be that very important segue into gas for South Central. The offtake points that are provided for in the contract are very critical pieces. The state identified four offtake points in Fairbanks, Delta and Yukon and also to South Central.

The contract does require an instate use study to be paid for by the producers. And with that I'll turn it over to Chuck.

MR. LOGSDON: Well, thanks, I appreciate the opportunity to speak to the symposium today. I've caught a number of the sessions, they've been great. I really enjoyed Carolyn's this morning. I want to talk a little bit about -- well, let's see actually I think there were some other bullets here. Let's see which one here, that wasn't it.

(Off record conversation)

All right. I want to talk about gas for Alaskans. Mary Ann has laid out the scenario of getting a mainline

pipeline built to commercialize their natural gas resources. That's -- we believe if you want to look seriously at what the future of Alaska is that's clearly -- that's a central thing and we -- she just went briefly over the sort of fiscal benefits that would provide for the state in terms of revenue and jobs, but I want to talk a little bit more about the gas for Alaskans.

And I'm going to talk about it in the context of a lot of work that's gone on over the last two years to move in that direction. And I know Harold could talk a lot about ANGDA's -- what they've been doing, but I want to talk about this in terms of the contract.

And Mary Ann already talked about the four offtake points. We've identified three. There's the option for a fourth one and some have talked about well, what if you had an offtake point on the highway route, say, maybe Haines Junction or somewhere else in Canada and take gas to tidewater as well, so that's potentially another option.

One of the biggest issues is, of course, once we get a pipeline in place coming off the slope, as Mary Ann suggested once you have infrastructure in place you're going to see a lot more exploration and this time people will be looking for gas not necessarily oil. Why would you look for gas if you had no way of commercializing it. You'd spend a lot of money, but have no way of getting your money back.

With a pipeline system in place it provides the opportunity for exploration. It's to capitalize whatever they find and that's what a pipeline can do, but what we'd like to see and we'd like to see up front is that pipeline be expandable. If the pipeline could be expandable then -- easily expandable then that raises the stakes even higher.

It's potentially -- we're talking about a pipeline that would bring four Bcf a day to market. With expandability you could see a pipeline initial design capacity for -- with added compression that could, you know, bring the capacity of it up to six billion feet a day and you could take all those good revenue numbers and jobs and escalate them even further.

But what do we got going? First of all, there's both a regulatory and a physical process. I mentioned a couple of things that you build into a pipeline. Primarily you identify how it could -- throughput could be boosted with - -- everything from simple compression to looping and you try to get that built in as the pipeline is constructed, but there's a regulatory process. And in the regulatory process that FERC has established so basically most expansions they have to make economic sense to happen.

The state, if we owned a piece of the pipeline, which is what the draft contract that's been negotiated allows for, in fact, calls for the state actually would be a part of the LLC or the operating company that could actually advocate

within -- as an owner to advocate for expansion.

And one -- the chart that Mary Ann put up there that showed the barrel equivalence of gas, one of the things that was kind of missing in that chart we drew it in and somehow it didn't make the final cut in the slides, but basically if we have a four Bcf a day pipeline and you do the numbers with the 35 trillion cubic feet of proved reserves, you're short about 15 Tcf to fill that line at four Bcf a day over the full 35 years.

So we're going to need exploration and we're going to need it fairly soon after the pipe- -- either before or after the pipeline starts flowing because it takes time to develop those gas reserves. And the pipeline is going to have space in it potentially because gas production- -- gas fields have a natural decline rate as well. They'll be room in that pipeline anywhere from 10 to 12 years after it starts up to start putting in new gas reserves, so first we've got to fill that.

And, secondly, if we get the kind of exploration that we think we may -- it may spark we should get -- there's a good chance we may have to start expanding the capacity even earlier.

What is the process for guaranteeing access to the pipeline? I mean, I just said we're going to encourage exploration. How do we ensure that there's access for everyone? Well, this gets down to the process known as the

open season where people who want capacity on a pipeline bid for what's called a fixed term capacity, FT.

It was -- I don't know how many of you caught the presentation on the Cook Inlet system. At least one of the pipe- -- I hadn't realized that at least one of the pipelines in the Cook Inlet system is a contract carrier and requires contract commitments to take a fixed -- a com- -- a transportation commitment.

As far as the regulatory, the FERC has already established rules for the Alaska gas pipeline open season which are designed to promote competition and provide opportunities for expansion.

Back to expansion again, the FERC can mandate expansion under the rules that they've established. That's kind of the only pipeline that I'm aware of in the U.S. where that's the case.

The initial open season would be conducted one and a half to two years into the construction planning process which under the draft contract that was negotiated that has to start 90 days after the contract is signed.

Under those same FERC open season rules the project sponsors would have to publish a perspective instate tariff. Those tariffs would be mileage and cost based so that there would be a separate tariff for each intermediate destination on the mainline, so there would not be a single postage stamp

tariff, but there would be a specific tariff for destinations.

And, of course, with the four offtake points we've identified, if they are purchases who want to buy at those intermediate points they would -- and sellers more importantly 'cause we're talking about people taking an ad tecum on the line that they would know in advance, have a good idea exactly what they would expect to pay.

So having said all that about the offtakes and the open season process let's talk in a very, very cursory way about some of the South Central energy issues that you guys have been focused on.

I've put up this area chart. It's the only one I have and I think you probably saw version of this. In fact, it's contained in a DNR publication, but what this shows is where does the gas go in Cook Inlet, to what kind of use. And it shows that basically the bulk of it does go to industrial use, the LNG plant, as well as the fertilizer plant. And power generation is the next in line as -- and the other one is, of course, to the gas utilities. So you can see that -- and I didn't identify -- the gray area, of course, is the gas that's used to produce oil and gas in the Cook Inlet.

The growth profile, it's actually been relatively flat since about 2000 or so, but with the exception of if you look at the power and -- power generation and the gas utilities, so that's -- you would think that would make sense as the

Anchorage area and everywhere has grown in population.

This is a nice little summary I took off an Enstar chart. You may have already seen this. It does point out that 67 percent of the gas generated in Alaska -- I mean, of the power generated in Alaska is gas generated, 15 percent hydro, 13 percent fuel oil, five percent coal with a total of 330,000 gas consumers in the state.

The -- kind of the -- missing that one here. Oh, and this is the chart you've seen many times, too. This is the famous cliff that Carolyn managed to avoid in her presentation. Although she presented a lot of solutions -- potential solutions, there are two vertical red bars. What you see on the -- on the green line, the top line is gas production and because gas production is essentially going to be gas demand, we have gas demand and we fill that by producing to meet that demand.

What you see is that we're right at the verge -- now, this is DNR numbers and I'm sure that there may be some modifications, maybe we can stretch that green line out, but we are literally on the verge of the cliff. According to the DNR projections next year we start a fairly radical decline in Cook Inlet gas availability, that's the first red line.

What does that mean? Well, if you look back to that area chart with respect to where does most of the gas go, well, most of it goes to the industrial uses and the consumers --

local consumers have priority so you're going to see some interruptions in gas supply which, of course, Agrium is already wrestling with.

The second red vertical line, that's where the gas production, of course, falls dramatically enough that we actually have shortfalls in gas to provide power generation and heating to Alaskan residents. I think D-day on this chart is about 2016 or so.

Now, of course, I've assumed a two percent -- I just plugged in a two percent growth in consumption. That number may -- you know, that may not be exactly correct and I think Carolyn identified conservation as one of the things we could do to deal with that issue.

But let's talk -- let's get back to something a little more optimistic here and look at why from an economic point of view a spur line would be such a great deal. In fact, for Fairbanks just getting a mainline going through Fairbanks is going to help a lot. What this shows is a theoretical cost advantage to local consumers in Alaska versus what the consumer in Chicago if -- assuming the gas ultimately is sold at a market price.

What you can see there on this chart is that if you start with the first bar and I've called that Cost to Lower 48. The total bar gives you the market price and from that you can subtract the top piece called the tariff and effectively that's

the tariff from the North Slope to that market, so in this case I think it's about 550 in MMBtu delivered to Chicago. Subtract off 2.70 an MM -- and actually I think I put this in Mcf's -- in thousand cubic feet. You subtract off the 2.70 and you're left with a wellhead value of 2.80.

So if -- now, on strictly a cost basis if you took that 2.80 and added the tariff to get that down to Fairbanks and that's estimated to be about 65 cents in Mcf you get a price of something just south of 3.50 in Mcf or something in excess of $2.00 Mcf cost advantage over the consumer in Chicago. Well, that's -- you would think that that margin would be enough to attract entrepreneurs that might be interested in obtaining gas in Fairbanks if they could get something close to that wellhead net forward price.

I think in South Central with the spur line, let's assume that you start with a net back price to Chicago of 2.80 and a 76 cent Mcf tariff -- I think that's a mistake there. It's a little bit more than that. I don't have the number correct here, but basically you'd have a cost advantage of -- that would be a little bit less. In this case I've estimated about a buck 28 in Mcf.

So I think the point is, is if -- and one of the things that we were looking at policy-wise, once we get a mainline in place we have the FERC open season rules, we have -- with regard to tariffs. The only things is that, you know, what

would the state's policy position be with respect to trying to ensure that gas delivered to Alaska utilities and Alaska entrepreneurs whether that's -- who may be involved in industries or whatever to take advantage of this cost advantage.

Anyway that's -- I just wanted to give you a little bit of preview of what could be and why I think the spur line from a mainline comes up into the top quadrant in the presentation you heard just before we came on.

So let me summarize real quickly, looking at Alaska's future in natural gas in the biggest possible picture from the South Central perspective if we get a mainline the whole darn state gets a big benefit, but also we get the opportunity to use some of that gas in both -- along the Railbelt for sure. I mean, the mainline is going to go through Fairbanks, plus we get a spur down to South Central Alaska.

The state revenue and economic boost from the project will benefit Alaskans for generations. I know that this is all -- something you probably already know, but the timing is such that the project will not come on time to -- probably to prevent that gap as illustrated in this presentation and which -- I'll just finish.

This may include wind generation, new coal generation, maybe LNG imports, coal gasification, the Blue Sky Project at -- for providing, you know, feedstock to the fertilizer plant

has already been discussed in yesterday's sessions, but frankly I -- you know, this -- I don't think this session is extremely timely because, I mean, for so- -- from the standpoint of South Central and the State of Alaska as a whole a seriously comprehensive solution to the dilemma needs to start now. Thank you.

COMMISSIONER SEAMOUNT: Thank you Mary Ann and Chuck. And thanks to the panel for some very good information.

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STEVE DAVIES

COMMISSIONER SEAMOUNT: And now we'll move onto the next panel, is Cook Inlet Oil and Gas Resources. We're going to get a bit technical here and we're going to start off with Steve Davies and David Hite you could come up here, too, please.

Okay. Steve Davies is a Senior Petroleum Geologist who has been with the Alaska Oil and Gas Conservation Commission for the past seven years. In addition to his work with government, Steve has 19 years of industry experience working for a major oil company and an Anchorage based geo-science consulting firm. He earned a Bachelors and Masters of Science Degrees in Geology from the University of Utah. Please welcome Steve.

MR. DAVIES: Okay. You know, following the excellent speakers of yesterday and today I have a pretty difficult task. I have to present some of the same material and I have to keep it interesting.

Because you all represent so many different interests and industry and agencies what I thought I would do today is give you a very general overview of the geology of the Cook Inlet basin. This is going to be Cook Inlet 101. What I want to review, how the basin and gas accumulations came about, how they were found and then I'll finish up with how the AOGCC's vision of the future. This will lay the groundwork for David

Hite who is up next who will talk about resources potential.

The Cook Inlet Basin is bound on three sides by faults, the Castle Mountain Fault, the Bruin Bay Fault and the Border Ranges Fault. We have the Alaska Range to the north, the volcanoes of the Alaska Peninsula to the southwest. And the Kenai Chugach Mountains. We also have the Aleutian Trench farther southeast.

Now, if we cut a slice through the earth's crust that runs through about here and we view it in cross section form you'd see something that looks like this.

The Cook Inlet has its origin about 70 million years ago at the beginning of the tertiary when the Pacific Plate began sliding or subducting beneath the North American Plate. The sediments and material on top of the plate were scraped up in a series of thrust plates that formed the Accretionary Ridge -- or Prism, excuse me and an oceanic trench formed.

As the plate subducts it begins to melt. The lighter fraction of that material rises and it finds its way to the surface and forms volcanoes. Now, between the volcanoes and the Accretionary Prism a basin develops. That's termed a Forearc Basin. The sediments that have eroded from the flanks of the volcanoes and from the Accretionary Prism are shed and washed down into the basin and form a thick deposit. These are the current names that we apply to those different features.

Now, this is an elegant model, but how do we know that

it really happens. If you take the earthquakes that are recorded in the Cook Inlet Basin over a three year period and you bought them in cross section form you see a picture that looks just like this, nicely displays the subducting plate.

So let's focus now on the sediments that were shed into the basin. The talk will focus on the Upper Cook Inlet, that's everything north of Augustine and Seldovia. If we cut a section through the earth and view in it cross section form we'll see a thick sequence of tertiary sediments that were laid down over underlying sediments.

This interval of sediments is about four miles thick and geologists have divided it into several different intervals that we call formations. From bottom to top we have the West Foreland, the Hemlock and the Tyonek. These are all intervals that contain oil and associated gas reservoirs. Overlying those we have the upper portion of the Tyonek, the Beluga and the Sterling. These contain non-associated gas accumulations. I'll talk about those terms a little bit further in just a moment.

Now that we've seen how the basin formed, let's see how the oil and gas form. There are five essential elements to the formation of any oil and gas accumulation. First of all, you have to have an organic rich source rock. You also have to have a hydrocarbon generation mechanism, either heat and pressure or bacterial action.

You have to have a migration pathway otherwise the oil that you generate stays locked in the source rock and is worthless. You have to have a reservoir rock, something that's porous and permeable that will host the accumulation. And you have to have a trap and seal mechanism, something that will stop the migration of the hydrocarbon and cause it to accumulate, that can be either a fold or a fault or it could be a reservoir rock that's encapsulated in finer rock. We call it a stratigraphic trap.

These are the essential elements that constitute what we call a petroleum system, that is, they're all the elements that are necessary to generate, migrate and trap hydrocarbons.

In the Cook Inlet Basin, the Upper Cook Inlet Basin, we have two petroleum systems, the Tuxedni-Hemlock, which are deeper, oil bearing reservoirs. They have gas associated with them, but it's wet gas, it's methane with heavier gases.

This is a stratigraphic column, it's what geologists use to depict the geologic section in a basin. Near the center is a column that has symbols that represent the different rock types for lithology. The dotted patterns are conglomerates and sandstones. The dashes represent finer grain rocks. And the horizontal lines are the coal seams that are interspersed throughout the section.

Now on this I've shown the Tuxedni at the bottom. Those are older, organic rocks, that's a siltstone. That's the

source rock for all of the oil within the Cook Inlet Basin, the Upper Cook Inlet Basin.

And we have the Hemlock which is the principal reservoir and holds about 80 percent of the reserves, the oil reserves in the basin. Secondary reservoirs are the Tyonek on the underlying West Foreland.

Now, let's look at how oil and gas form. We'll start with a simple model here. It's a source rock, a reservoir rock with an overlying seal, capped by overburden. To make it a little more realistic let's fold it and warp it and incline it to make it look like one of the limbs of the Cook Inlet Basin.

Now, as you go downward through the crust of the earth heat and pressure increase and at a depth of about four miles in this particular basin those conditions become sufficient that they will break down organic material and turn it into oil. That's called the oil window.

Now, in the Cook Inlet Basin as the basin subsided the Tuxedni source rock entered the oil window. Oil was generated and since it's mobile if there are migration pathways available it will migrate up structure until it hits a barrier. In this case we showed it as a fold. It could be a simple fault. Anyway, the progress is impeded and the oil begins to accumulate.

As oil continues to be generated, if you exceed the capacity of the trap and there's an exit route, the oil will

take it and move up structure. So you can develop a series of filled structures, either folds or fault blocks, on the limb of a basin.

Now, once you go down about five miles pressure and temperature becomes sufficient to cause any organics or any oil that's still trapped in the source rocks to convert to gas, so gas and oil now are both being generated. They both migrate and they're trapped and if there's sufficient gas present the gas cap may developed. So you can see that there's potential over time to develop a very complex oil distribution pattern in the basin.

Back to our reservoir. This is the tertiary sediment wedge that we talked about earlier. You can see that in the basin on the west limb several oil fields have accumulated, oil and gas associated fields. And on the right we see the Swanson River and Beaver Creek fields. If we look at the distribution on a map this is what we see.

Now, yesterday one of the speakers pointed out that, you know, there is still plenty of room for exploration and that's true. If you look at the east limb there are only two oil fields. If you look at the west limb there are four so there's exploration potential off to the east.

Now, the Upper Cook Inlet Basin contains two petroleum systems. There's another one that I just briefly labeled or prudently (ph) labeled the non-associated gas petroleum system.

These tend to be shallower reservoirs. They're gas only with no associated oil. It's dry gas, almost entirely methane, excellent fuel and it's formed by the bacterial action on -- action of bacteria on coal.

Non-associated petroleum system reservoirs of the upper portion of the Tyonek, the Beluga and the lower portion of the Sterling. The gas is generated from the source rocks you can see indicated on the right by the red arrows. Those are the coal beds that are interspersed throughout the system.

If we look at our tertiary wedge you can see that there are non-associated fields on both sides of the basin. If you look at them in map view you can see that they're more widely scattered throughout the basin.

So now that we know how they formed let's see how they were found. Commissioner Kelly and Bill VanDyke went through a lot of this material yesterday and what I'm doing is showing it in map form. I'm a geologist and I need maps to show me the spatial and temporal orientation of things and to see trends. So what I've done is plotted all the exploration wells on a series of maps.

Between 1900 and 1919 a total of six oil exploration wells were drilled. All of them on the Iniskin Peninsula. Four of them near Oil Bay, two of them near Dry Bay.

From 1920 to 1949 three oil exploration wells were drilled. One, northeast of Palmer, the Old Wildcat No. 1 in

northeastern Anchorage and the Iniskin Bay Associates well, this is the one that was mentioned yesterday. It was financed by Walt Disney and Hal Roach and Cecil B. DeMill, other Hollywood luminaries.

1950 to 1959 brought a period of increased exploration activity. There was a lot of drilling up in the Houston area, the Houston core holes, the Rosetta wells. The initial drilling occurred at Swanson River, Kenai, there was a well at Deep Creek and the final two wells on the Iniskin Peninsula. The results of that drilling, one oil field was discovered, the Swanson River field.

From now on all the oil fields that you see will be underlined. The gas fields with be highlighted with the circles. So during the time period one oil field and one gas field were discovered. The estimated ultimate recovery from these discoveries was 230 million barrels of oil and about 2.7 trillion cubic feet of gas.

1960 to '64 was the onset of the boom here in Alaska. (indiscernible) gas exploration well in the Kenai gas field. Offshore was open to drilling. The first wells were drilled in 1962 and the results of that activity were one oil field, the Middle Ground Shoal field was discovered, and six gas fields. The estimated ultimate recoverable is 210 million barrels of oil and 3.7 trillion cubic feet of gas.

The first platform, Shell's Platform A was set in the

Cook Inlet in 1964.

During the next five years, '65 to '69, was the period of greatest activity in the basin. 107 exploration wells were drilled, 103 for oil but four were dedicated to gas exploration.

Offshore drilling was common. 13 platforms were installed in the Cook Inlet. 13. It's just hard to fathom that level of activity in a basin. 13 platforms. And they were all brought on line.

You'll notice the flaring here. That was a common practice in the Cook Inlet until the regulations were changed in the mid '90s. The results of that activity; five oil fields were discovered, six gas fields, 920 million barrels of oil and 1.7 trillion cubic feet of gas.

'70 to '74 brought a distinct drop in interest in the Cook Inlet Basin as everyone's attention focused on the North Slope. 24 exploration wells were drilled all for oil. The result was the discovery of the Beaver Creek field with 7 million barrels of oil and 220 billion cubic feet of gas.

'75 to '79 activity was about constant. 28 wells were drilled, but this time eight were targeted for gas. The result was the discovery of four gas fields with an estimated ultimate recovery of 230 billion cubic feet.

The decade of the '80s didn't see the drilling boom that went on, on the North Slope. There were only 20

exploration wells drilled in the Cook Inlet Basin, one gas field, Wolf Lake was discovered with 1. Bcf of estimated ultimate recovery.

The '90s were about the same. 25 exploration wells, but six of them were targeting gas. The West McArthur River oil field was discovered as was the Lone Creek gas field. Estimated ultimate recovery from these, 14 million barrels of oil and 14 Bcf.

That brings us to the last six years. We've seen a relatively boom in interest in the Cook Inlet. 59 wells have been drilled, exploration wells that is, 13 of them for oil, but 46 specifically seeking gas. Three gas fields were discovered, Three Mile Creek, the accumulations that now constitute the Nickolai -- or excuse me, the Ninilchik unit, and Happy Valley.

It's hard to get your arms right now around the estimated ultimate recovery. The best estimate that we can make is about 170 Bcf, plus or minus with a question mark.

So to summarize, over the past 106 years, 335 exploratory and stratigraphic test wells have been drilled in the basin. They've discovered nine oil fields, 22 gas fields with 1.4 billion barrels of oil and 8.9 trillion cubic feet of gas estimated ultimate recovery.

So the question comes up is the basin mature? Has it been over-drilled? Well, if we limit our area of interest to

what I've shown here on the map between the Castle Mountain Fault and the Border Ranges Fault I count 297 exploratory wells. That works out to about one exploratory well for every 30 square miles.

To help put this into perspective let's take a look at the Beluga River field. This field is two miles wide and six miles long and has produced about a trillion cubic feet of gas.

If we take a 30 square mile rectangle and superimpose it on a street map of Anchorage it stretches from 15th Avenue down to O'Malley, from Minnesota on the west to just past Boniface and Birch on the right and if we drill a well right at the Lake Otis Post Office, Lake Otis and Dowling we see that it's possible to miss something as large as the Beluga River Field. In fact, it's possible to miss two of them.

The same goes for the deep drilling in the basin, 42 wells have been drilled deeper than 14,000 feet, only six have exceeded 16,000 feet so there's still plenty of room for exploratory drilling. One thing to note on this map is the circles that I've used to highlight the locations of the wells that reach five miles in diameter.

So that brings us to AOGCC's prediction for the future. If there was somebody here who wasn't here yesterday this is for you. This is the production graph from the Cook Inlet gas fields. That's the present. This is what we face in the future if we do nothing. Even if you layer in the undeveloped,

probable reserves the picture doesn't change much.

You're also familiar with this graph. What we've added are two additional curves. The dashed green line represents DNR's forecast of supply and the solid blue line represents AOGCC's vision. You can see that there is some variance between the three agencies, but the overall picture is the same decline.

So that brings us to my conclusions. There's still plenty of opportunity left for exploratory drilling in the Cook Inlet Basin. The three agencies have similar reserves in production forecasts if we do nothing. So what that means is if we continue the course there is no exploration drilling or outside source brought in, in a very few years we're going to face a very big problem. Thank you.

COMMISSIONER SEAMOUNT: Thank you, Steve. Another way to put it in perspective is there's about 14,000 square miles in Cook Inlet Basin. It's about the same area as San Juan Basin in New Mexico. The San Juan Basin has 29,000 wells in it and they're still making discoveries there. Cook Inlet Basin has 1,000 penetrations in it, so as Steve says it's very under explored.

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DAVID HITE

COMMISSIONER SEAMOUNT: Okay. Our next speaker is David Hite. He's a consulting geologist residing and working in Anchorage. He received his BS in Geology from Oregon State University in 1962 and his Masters of Science and PhD from the University of Wisconsin in 1964 and '68 respectively.

He started in the petroleum industry with ARCO in 1967 as a research geologist in the Plano, Texas lab. Subsequently he worked for ARCO as an exploration geologist, staff geologist and manager of both exploration and technical support groups. He left ARCO in 1992 and has been a consult since that time.

While with ARCO he spent the great bulk of his career working Alaska, commencing with work in the Cook Inlet in 1967. He moved to Anchorage full time in 1979 as North Alaska District Geologist and has been here ever since.

As a consultant David has worked for major corporations, Native corporations, independent and small oil and gas companies and has contracted with federal agencies such as the DOE. Let's welcome Dave.

MR. HITE: Well, Steve has set me up beautifully so I think we're not going to have much of a problem getting through the first half dozen or so of my slides if I know which button to push. Okay, we're off and running.

We managed to skip the first slide, but that's all

right. It's simply an introduction that pointed out that we were going to be talking about additional, potential reserves in -- oh, there it is, in Cook Inlet.

This is -- much of the presentation this morning and this segment at least will be taken from a report that SAIC did for the Department of Energy so if you've read the 2004 South Central Alaska Gas Study you're probably going to be bored somewhat until we get toward the end of it.

Much like Steve said I'm going to concentrate on the Upper Cook Inlet. If you'll note the illustration here is pretty much the same as Steve had. We'll be looking at -- if this thing works, ah, forget it.

North of the Castle Mountain Fault in the Susitna Basin -- okay, great, thanks. The Susitna Basin, we're not going to be discussing yet, south of the Augustine/Homer/Seldovia arch is OCS, that's probably going to be discussed by Drew Comer in a few minutes so, again, I'm like Steve I'm going to concentrate in the Upper Cook Inlet Basin.

I've got a slightly different stratigraphic chart than Steve had to give you a perspective of what I'm going to be talking about. Most of the focus of the talk will be on the dry gas that Steve was referring to in the upper part of the section which is sourced and reservoired in the upper part of the Kenai group, the upper Tyonek, Beluga and Sterling formations, but there will also be some discussion toward the

end on the gas sit- -- excuse me, on the oil situation and the associated dry gas which is generated out of the Tuxedni group and reservoir out of the lower part of the tertiary and the West Foreland, Hemlock and lower Tyonek.

And, again, we're dealing with the thermalgenic (ph) petroleum system in the lower part of the section and a biogenic petroleum system for the upper part of the section.

You'll note here I'm using a slightly different number of exploration wells than Steve referred to. We went through and, sort of, picked out wells that were very close together and I don't think in everybody's classification it would be considered an exploration well, so I'll be dealing with a number that's about 60 or 70 less than Steve referred to.

However, all it does it make the values of exploration success higher than Steve would have them. If you used Steve's numbers the exploration success would even be lower than I'm going to refer to here, so it does not necessarily make the picture look any rosier to use Steve's numbers. It just says it takes an awful lot of luck as well as knowledge and endeavor to find a hydrocarbon accumulation.

Right now we're looking at 220 exploration wells within the Upper Cook Inlet most of which are shown as dots on that map. The nine wells in Susitna Basin north of the Castle Mountain Fault which -- not all of which are shown on there and I did not show any of the wells drilled in the OCS and this

does not include any coal bed methane. This is purely conventional gas and/or oil.

This table I hope you can follow it, sort of takes some of the same data that Steve was addressing a few moments ago and places it in a time frame of five year intervals. We're talking about exploration wells drilled, gas and/or oil fields discovered and the success ratio. As you can see in the early stages few wells -- we're starting from 1955, mid '50s to current date. Exploration wells drilled in that first half decade were 17. There were four -- or five discoveries, that's a 29 percent success ratio. Very high in terms of gas.

And most of those gas wells I will point out were not explored for -- they were found by accident while one was looking for an oil accumulation. There was no reason for anybody to be looking for gas in the early '50s and '60s, there was no market for it as a consequence we were just fortuitous to have found those things.

Two or three points I want to make exploration activity has decreased over time and I think this was touched on yesterday. A good portion of the energies and resources of the industry moved north very rapidly in the lat '60s and early '70s with the discovery of Prudhoe Bay. And only the operators who actually had sustained production in Cook Inlet stuck around to do much of anything.

Basically, like I say, here all the exploration I've

been corrected until the mid '90s was for oil, there were some exploration activities, but very minor for gas prior to that. Recent activity in the last five years, as Steve pointed out, has been focusing on gas. And to date we have found approximately 10,000 -- excuse me, 10 Tcf of gas in place and approximately eight and a half Tcf estimated ultimate recovery.

In terms of the oil picture we're looking at -- Steve used a little higher number, I'm using 3.7 billion barrels of oil in place with about 1.36 billion barrels of oil, that's estimated ultimate recovery from the activities to date.

This next slide refers to accumulations not necessarily oil -- gas fields. We're counting 28 gas accumulations, eight oil accumulations -- I'll by (ph) nine now days. This is two, three years ago. And two distinct northeast/south -- oops, hit the wrong button -- northeast/southwest trends. The oil fields are shown in green and the gas fields are shown in red on that map.

These are largely controlled by these large anticlinal transit developed in the basin similar to the illustration Steve was showing in terms of the development of Cook Inlet Basin.

Now, the general characteristics of the gas accumulations in Cook Inlet -- and on the next few slides you're going to be directed primarily to gas, is that the gas by origin is 94 percent biogenic. That's that dry gas sourced

and reservoired in the upper part of the section in Cook Inlet. The upper Tyonek through the Sterling formations. Only six percent is thermalgenic associated gas found in reservoirs with the oil in the West Foreland, Hemlock and lower Tyonek.

The primary reservoirs for the gas are the Sterling which has about 57 percent of the known accumulations, the Beluga 14 percent and the Tyonek 25 percent. Two of that 25 percent in the Tyonek incidentally is associated thermalgenic gas. The rest of the gas which is thermalgenic in origin is in the Hemlock and West Foreland formations.

Currently the AOGC reports 29 gas fields or discoveries. Field size, three large fields, the Kenai, Beluga and North Cook Inlet fields account for approximately 80 percent of the expected ultimate recovery. So three of those fields found very early in the history of the exploration of the basin have the bulk of the reserves. Now they also probably, as Steve -- excuse me, not Steve, but Scott Jepsen mentioned yesterday, probably have the greatest potential for additional reserves additions, reserve growth.

Now the charts, as Steve pointed out yesterday showing the cliff, do not take into account reserve growth within (ph) unknown fields and they do not take into account future exploration potential. Those charts with the big cliff falling off about now basically are saying what we known and we have discovered today. They do not -- they say we need to do

something like developing these extra reserves within the fields or explore for them if we're going to maintain production in Cook Inlet.

One thing about the field size distribution, and it's going to be the focus of the next few slides, is that world-wide oil and gas fields are accumulations are logged normally distributed per basin. Meaning you have a few number of large fields increasing the number of smaller fields and in terms of where the oil is reserved and reservoired.

In Cook Inlet we'll see -- we show an illustration or two coming up, there are gaps in this distribution. Oil fields -- excuse me, gas fields and to a lesser extent oil fields do not have a log normal distribution in Cook Inlet. Discovered fields do not have a log normal distribution. The implication being that there are undiscovered fields and that's what we need to go out and look for.

Here's a statement, the discovered fields in north -- in Cook Inlet do not conform (ph) to log normal distribution. The lack of log normality in the gas field size distribution was examined in a DOE report -- again, this is the South Central Alaska Natural Gas Study, the level of gas endowment in the basin necessary to achieve a log normal distribution status was tested.

Oil was not included in this earlier study, but we did sort of a back of the envelope calculation for the presentations

today and I'm not quite as happy with it as I am with the gas, but we'll talk about that in a moment.

Using the USGS field classification -- field size classification we can sort out the fields that we have found or accumulations that have been discovered in Cook Inlet. And you can see these fields range from class size zero to a class size nine. We do not have any tens currently found in Cook Inlet, but that class size zero is less than six billion cubic feet of original gas in place.

We're not talking about reserves, we're talking about original gas in place. An average value for recovery from Cook Inlet gas fields be something like 85 percent.

We do have three class nine fields. This is original gas in place volumes again. That is North Cook Inlet, Beluga and Kenai. Those are the three which constitute more than 80 percent of the reserves. And if you'll notice taking a look at this last column over here those three big fields have seven of the potential 10 Tcf gas in place.

Now let's take a look at the log normal distribution aspect. We did not construct one for the 10 Tcf endowment, but we've constructed log normal distributions at five Tcf intervals from 15 to 35 Tcf. Again, this is gas in place in Cook Inlet. This is not recoverable gas. And it includes the currently discovered fields.

On this graph -- from both of these graphs red

represents the current fields known in Cook Inlet. The left side represents number of fields per class size. The right side represents oil -- excuse me, gas in place per class size. As you can see in both cases there's a significant gap. There are no fields, for instance, in class size seven and there are no reserves attributable to those class sizes. This suggest right away there's something out there missing and it's fairly significant in terms of size.

We went then to a second extreme. This is the other end of our spectrum. This was using the 35 Tcf original gas in place and this distribution really, sort of, warps the world. It's kind of hard to conceive that that really matches anything present in Cook Inlet.

So we went back and filled in the gaps between the two. This is the 15 and the 35, sort of, bracket what we consider to be a reasonable distribution. Again, this would suggest a very large number of missing fields with very large reserves and even with the exploration history of Cook Inlet it's kind of hard to believe that we would have missed that many large fields.

So backing down to the 20 to 25 to 30 this one doesn't seem to fit a log normal distribution much better than the 15 and the 20 case. We still feel this is inadequate to represent a log normal distribution.

Bumping up to the next two 25 Tcf, we're starting now

to get something that approaches a log normal distribution in terms of field size and reserves distribution per field size.

And finally in the 30, again, just, sort of replicating what we saw in the 25 case. So our best interpretation of the data is that the basin endowment is probably somewhere between 25 and 30 Tcf original gas in place. Ten Tcf of that have been discovered and are in the existing known fields. So that leaves us something like 15 to 20 Tcf of gas sitting around out there somewhere undiscovered to date.

Now where is it? Well, there's a possibility we simply haven't discovered -- and let me say that. First of all, this analysis -- boy, what did I do?

UNIDENTIFIED VOICE: Hit the wrong button.

MR. HITE: Yeah, you're right. There we go. This analysis does not provide any evidence on where the fuels would be located in Cook Inlet, but I can suggest what kind of features these reserves may be in.

There has been essentially zero stratigraphic exploration in Cook Inlet. Everything has been -- that's been drilled to date has focused in on the anticlines, these large structural up-warps that Steve showed in the cross section during his oil generation and migration process. They're very easy to find seismic -- well, relatively easy to find seismically and they are complicated, of course, by faulting and the like so even within those large structures there may

still be unexplored fault blocks.

I think Scott Jepsen and a couple of other people yesterday mentioned, you know, taking a look at the backside of some of these features. The fa- -- and this -- actually I think that was Aurora presentation. The under-thrust west sides of many of these things have not been adequately explored, the existing fields. There may well be reservoirs and accumulations there.

The stratigraphic trapping mechanisms, most of these sediments in Cook Inlet -- well, all the sediments in Cook Inlet are basically non-marine. They do not have wide, lateral extent. A sand package does not go on for 20, 30, 40, 50 square miles as it tends to have a linear -- a few hundred, a few thousand, maybe a couple miles wide package, a few miles to maybe tens of miles long and it's not a straight line. It's sinuous.

You can go out and take a look at rivers and valleys and river systems all over Alaska that's what you're looking at. Look at the Susitna Basin. It is probably a modern day analog of what one would see in much of Cook Inlet at any snapshot in the last 25 or 30 million years. Trying to find those individual riverain (ph) channels that are running out there that happen to be charged with oil -- or excuse me, in this case gas is a no mean task. It takes a lot of work.

3-D seismic and the like are making things like this

much more possible to do. However, Cook Inlet is full of coals. Coals help screw up your seismic interpretations in terms of being able to identify things that may be gas bearing especially if you're looking for direct hydrocarbon indicators which is beyond the scope of what I wanted to get into right now.

But nonetheless, there's a lot of opportunities out here for additional reservoirs and in many mature basins around -- and this Cook Inlet is not a mature basin in terms of exploration by any stretch of the imagination despite what you may read in the papers. Many mature basins, half or more of the reserves ultimately end up being in stratigraphic traps. You just apply that rule of thumb there's probably half again or in as much gas and or oil floating around out here as we have found to date.

Distribution of -- taking a look at that chart summarizing what we just looked at, the distribution of gas by field and field size is right in here. You may be looking in the neighborhood of 40 -- up to 40 additional fields out here in terms of our gas possibilities and with up to 10 to 15 trillion cubic feet of additional gas. That's a lot of gas.

As was pointed out yesterday though, this is not an inexpensive undertaking. We may be looking at three to five or $6 billion to go out here and adequately explore for this.

Not only that next if you take a look at this next

chart we have additional problems. Down here is the seven -- or 8 1/2 Tcf that we expect to recover. Here's that 1 1/2 Tcf that we expect not to recover from the 10 Tcf discovered to date. We do expect there to be additional gas coming out of those known fields. This is what we call reserves growth. This is by people like ConocoPhillips and others who have the data that we don't have who are going back in and looking at bypassed intervals, reevaluating old log and well tests and saying, hum, maybe we should maybe look at the stuff we've got behind casing between 3,200 and 3,800 feet that we ignored before. Going back in, reevaluating, re-completing it, and finding you've got another 200 billion cubic feet of gas that you didn't recognize you had before. That's reserves growth.

Or in the case of the Beluga field, my understanding is even today the east side of the Beluga gas field is poorly defined and there may be extensions that are possible in that direction. Just enlarge the whole area of the Beluga gas field, not only develop additional reserves within bypassed intervals within the field.

And bearing in mind again, that we're dealing with channel systems. Just because they happen to be draped across the crest anticline and you're drilling at the high part of an anticline and you find the gas in that channel, it doesn't mean that there's not another channel here at 500 feet down slope on the anticline that is totally encompassed by the surrounding

shales and it's purely a stratigraphic trap on the flanks on it. And until someone decides I'm going to take a bet and go out there and drill that thing, they won't find. And I'm convinced in my own mind there are literally dozens of these type of traps present in every one of these major gas fields that most of which have not yet been found.

Now, taking a look at what we would expect to have still floating around out there with this pie diagram shows about 13 1/2 trillion cubic feet of gas in place, again not recoverable, but in place. We expect, perhaps, as much as 6 Tcf of that to be inaccessible. Now I wouldn't be surprised if that number is bigger. And we say inaccessible, under the Kenai Moose Range and places like that you simply can't get to at least under current conditions. So we're not looking at this entire potential endowment of gas in Cook Inlet for adding reserves in the future. We're looking at some fraction of it, hopefully, a significant fraction of it.

We did, as I said, a quick -- hum, I am pushing the right button. May be the computer. There we go. We did a quick and dirty calculation in terms of (indiscernible) distribution for the oil using the oil distribution class sizes of the USGS and the Cook Inlet gas oil fields fall in the 10 to 16 class range. This gives you an idea of the major accumulations we have out there. And our estimates of the original gas oil in place.

Exciting examples from yesterday, we probably should revise Swanson River to 400 and McArthur River to 1,600 million barrels. But this gives us a very similar, about 3.8 billion barrels of oil in place with the current cumulative production of about 1.3 billion barrels, and general recovery factor of about 35 percent. Boy.

UNIDENTIFIED VOICE: Maybe the battery's dying.

MR. HITE: Yeah, it might be. Do you have a replacement? We'll see. Ah, it wasn't me.

What we did then was run about four simulations taking a look at original oil in place volumes and ranging from 6.6 billion barrels worth of oil endowment to about 12.

Again, you'll note there is a gap in the reserve -- this -- unfortunately, this set of slides is reversed from the other. Field number is here. Reserves per field is on this side in this set of slides. So you'll note there are no fields discovered in here or here. How we're responding to this quantity of reserves in the 6.6.

Going up to the next category, 8.5, again, we follow the same pattern. And the same thing you'll see goes throughout, so we won't spend a lot of time debating that point, but the point is there are many -- any simulation you run there are missing fields. And missing fields fall in the primarily and the about 2 point -- let me go back one. In the 238 to 500 in the 16 and the -- about 30 to 60 million barrel

range. Not huge fields but, nonetheless, significant fields.

In there upper cases you'll also note that there's evidence supporting the possibility of something bigger than we have found to date. I'm sure the folks at Escopeta who are looking at the Kitchen prospects look at something like that with fondness in their hearts 'cause they're believing they're seeing something in that magnitude.

This just summarizes the number of fields that are potentially available out there and the reserves based on these various simulations.

What I'd like to do then briefly is summarize these two sets of illustrations. Again, I apologize for the oil being as not as complete as the gas. We just did that at the last moment for completion's sake and I'm not that comfortable with what we've got there. I think we need to look at it a little more closely. In fact, that holes exist in the distribution is indisputable. What the total endowment is, is another question.

All right. Historically exploration has been for oil. Virtually all gas and oil, as it turns out, were found prior to 1970. And virtually all of the gas was found by accident while exploring for oil. Oil exploration has been for structural plates. There's probably as much gas, and as you'll see in a moment, oil left to be found in stratigraphic plates. This first -- by the way, this first series of conclusions are

applied primarily to the gas.

Non-associated biogenic gas comprises 94 percent of the produced gas and is the objective in future exploration efforts. The current fields have about 8.5 Tcf of economically recoverable reserves and represent about 10 Tcf of original gas in place or -- and oil -- gas endowment. This probably represents only a fraction of the basin's potential. We would estimate that there's at least that much potential left in the basin, maybe twice that much.

Number of fields and field size are expected to be log (ph) normally distributed. As we saw from this evaluation they are not. And there are missing fields in the 200 Bcf to 1.5 Tcf range.

In terms of oil exploration it's been focused on the seismically well defined anticlinal features with no evaluation, once again, of the multitude of stratigraphic or combination stratigraphic and structural traps that are developed within the basin. The known producing fields have an expected ultimate recovery of about 1.36 to 1.4 billion barrels of oil and have about 3.7 billion barrels of original oil in place.

The various endowments of the original oil in place strongly suggest that there remains at least as much undiscovered oil in the basins as has been discovered. The oil may be in structures off limits to industry,

Stratigraphic/combination traps or in largely under-explored under-evaluated Mesozoic reservoirs. We didn't touch on this, but Steve alluded to this earlier when he was talking about no drilling below 16,000 feet. The original exploration in Upper Cook Inlet was actually targeted Mesozoic reservoirs. Those horizons on the Iniskin Peninsula and the Alaska Peninsula which actually had the oil seeps in them. They believe to be present at depth and the cretaceous and Jurassic older rocks beneath the tertiary section were the primary objectives in the Swanson River original discovery well.

As with the gas fields, the oil field size should be a log normal distribution. The picture as I stated is not as clear cut as with the gas but there are fields missing in the 128 to 256 and 364 -- excuse me, 32 to 64 range and possibly in the fields greater than 2 billion barrel range. That one's a big question mark.

To better understand the additional potential of the basin in terms of the stratigraphic aspects -- and this is something I was asked by Bob Swenson who's the director of the Division Geological and Geophysical Surveys, the DGGS is undertaking a stratigraphic study of the Cook Inlet tertiary to better get a handle on what is the character and nature of the sedimentary section and the tertiary of Cook Inlet.

And as we speak they have a field party operating out of Homer looking at the stuff around Kachemak Bay, Seldovia,

and those portions of the Inlet. And this will be an ongoing, two, three, perhaps four year study. I don't know if David LePayne is here today, but Dave's heading it up for the DGGS and was in town for this session.

That pretty well summarizes what I want to say in this regard. I think I can just sign off with saying there's a lot more gas out here to be found. It's going to take a concerted piece of work and a fair amount of money to do it, but I can't see any way in which we're going to -- if, indeed, we come to this cliff no gas pipeline is going to get us here in the next six, seven, eight years. We're going to need gas in the next six or seven years. We're going to need to either go out and explore for it or import it. That's my opinion. Thank you.

I lost the flip of the coin so I get to do this next presentation, so Charles Thomas said he's got enough to do today. And I can play this game. So we'll see what we can do. Hopefully this time the machine will pay attention to me. One moment. Okay. Well, while he's setting that up I'll just give you -- tell you what we're going to be talking about.

This is going to be Use of CO2 in Economic Oil -- or Enhanced Oil Recovery. We're going to talk a bit about the background. The potential applications and potential applications to Cook Inlet oil reservoirs.

This was -- this study was originally undertaken as part of the Agrium coal gasification study. And it was a way

of looking at what might be done with the CO2 as a byproduct of that coal gasification process.

We're not in business?

COMMISSIONER SEAMOUNT: Okay. We have a break scheduled for 10:00 o'clock. Why don't we take that break right now while we sort through our technical difficulties. How about, let's say be back at 10 after 10:00.

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(On record)

COMMISSIONER SEAMOUNT: It looks like we're ready for our next talk. One thing to think about as far as reserve potential, in the '80s Dr. Leslie McGoon of the USGS did some geochemical work and estimated that only four percent of the oil generated by the Jurassic had ever been identified. So if you do the back calculation of, let's say, there's four billion barrels that have been identified in Cook Inlet Basin, that suggests that 100 billion barrels have been generated which means there's 96 billion barrels of oil that have not been accounted for. Now some or a lot of it probably escaped to the surface a long time ago, but there's still should be a lot of oil left somewhere.

Another thing about it is out of the 1,000 wells drilled in Cook Inlet Basin only 53 have even gotten close to where the oil was sourced and generated. And that would be the Jurassic. Four of those Jurassic sections were tested and all four had some sort of optimistic result to it.

Well, in any case let's go on with the CO2 study and David Hite again.

MR. HITE: Thanks, Dan. Okay. We've got -- as I had started to mention and I'll repeat for those of you who were distracted by the fact that nothing was on the screen. We'll be talking about CO2 and Its Uses for Enhanced Oil Recovery.

To set this up, give a little background on -- very brief background on CO2. Its -- the methods of CO2 enhanced oil recovery, the applications in a general sense, elsewhere in the United States, and briefly worldwide. And then take a kind of a quickie -- quick and dirty look at what benefits there may be from CO2 enhanced oil recovery for the Cook Inlet reservoirs.

Now, I'll preface this all by saying right now there's no source of CO2 to do enhanced oil recovery in Cook Inlet. And the -- what I'm talking about here today basically came as -- again, as a byproduct of the Agrium coal gasification study which was done for DOE, NETL. It is -- or soon will be on the internet, is that right, Charles? It should be out very shortly on the internet so you can get this in all its full glory there as part and parcel of the entire Agrium coal gasification study that was performed recently.

The -- you know, the CO2 that would be generated by this plant would apparently be in the neighborhood of one million -- 100 million cubic feet of gas per day. And we'll use that as a base for going forward in our discussions.

So let's take a look then at CO2 as a tool for enhanced oil recovery. This purpose as with many other forms of enhanced oil recovery is to restore formation pressure and improve oil displacement or fluid flow in the reservoir. Factors that influence the effectiveness of a CO2 flood are

both reservoir and fluid properties. In the reservoir temperature, pressure, and depth which are probably quite close interrelated. Porosity of the reservoir, the permeability, the amount of net pay, and the remaining oil and water saturations in the reservoir when the CO2 flood begins.

And in terms of the oil itself, the API gravity and the viscosity affect the ability to which one can perform a CO2 flood.

With CO2 floods there are two basic mechanism. There's a miscible flood and an immiscible flood. In the miscible floods which is the more effective of the two types, pressures have to be above minimum miscibility pressure or MMP which is generally about 1,100 psi. That can vary somewhat depending on the oil gravities and viscosities. An API of gravity greater than 22 degrees API is necessary for a miscible flood, and viscosity generally should be 10 centipoise or less.

In the immiscible flood these occur at low pressures, generally speaking, 800 to 1,100 psi, API gravities of 13 to 21.9 degrees, and viscosities considerably greater than 10 centipoise. No flooding will occur, miscible or immiscible, at depths less than 1,800 feet and API gravities less than 13 degrees. If you've got really heavy shallow oil forget about it.

In order to evaluate whether or not a reservoir and its contained oil as a viable candidate for flooding with CO2,

screening criteria are generally applied. And this is a very brief simplistic approach to it. This comes from Taber and others, 1996, so if you're interested in taking a closer look this is where you can go.

For CO2 miscible floods were looking at two things in this case, depth which is -- and ends up being pressure, and the API gravity. Heavier the oils -- excuse me, the lighter -- the higher the gravities or the lighter the oils, the shallower depths to which a miscible flood is possible. API gravities greater than 40 can be performed at depths up to 2,500 feet.

And as you go on down the scale you'll notice with increasing gravity -- or decreasing gravity, increasing weight of the oil, the depths becomes concurrently higher. Below 22 degrees API the tests of the reservoir and oils fail the screening for a immiscible flood -- for miscible flooding -- for miscible -- immiscible -- excuse me, for immiscible floods the API gravities of 13 to 21.9 are effective and you need depths, again, greater than 1,800 feet. Once again, anything more or anything less than 13 API gravity cannot benefit from CO2 flood.

The characteristics of a reservoir and/or oil that result in the most effective miscible floods, and we want to concentrate on miscible floods if we can 'cause they're far more efficient than immiscible floods. Contrary to what many people seem to believe the better your water flood, the more

effective your water flood, the more effective the CO2 flood is going to be. In fact, as a prerequisite prior to a CO2 flood that you do a water flood.

Prior to Co2 flood and after the water flood the oil recovery factor should be somewhere in the 20 to 50 percent range. Oil reservoir depths must exceed 2,500 feet, we saw that earlier, to attain CO2 minimum miscibility pressure which is a function of the lithostatic pressure, bottom hole temperature, and oil composition. Oil gravities greater than 27 degrees API and with oil viscosities less than 10 centipoise are ideal for miscible floods.

If a reservoir passes the screening process there are several empirical rules of thumb that can be applied to predict results and operating parameters of the CO2 miscible floods. And, again, the reference for what I'm about to talk about comes from Nelms and Burke, 2004. These basically are the CO2 EOR of the original oil in place and the best reservoirs. In other words, the enhanced recovery is basically eight to 11 percent of the original oil in place volume. If you've got a billion barrel reservoir oil in place, you've recovered 300 million barrels of it, you can expect to recover an other 90 to 100 million barrels if you have a good miscible flood.

There's another rule of thumb, this is given to the original oil in place, say you're dealing with a individual reservoir that you don't really have a good value on, the rule

of thumb is about 25 percent of cumulative production from that reservoir can be added with a CO2 -- with a miscible CO2 flood given that your reservoir passes all the screening parameters.

Immiscible CO2 recoveries are usually 50 percent less than miscible CO2 floods. To achieve a CO2 miscible flood the MMP is roughly equal to the initial bubble point pressure. For those of you who aren't engineers, forget about that one. The CO2 injection requirement is seven to 8,000 cubic feet of CO2 per barrel of oil recovered. So you've got -- again, this is the comment by Nelms and Burke. Other authors have cited volumes as low as 2,000 cubic feet of CO2 per barrel of recovered oil.

So being on the pessimistic side you say you're going to need about 7,000 cubic feet of CO2 to get a barrel of oil out of the ground. I'm assuming that is if oil chemistry, oil properties change, they get more favorable, you can probably get by with lesser volumes of CO2. That's my assumption based on what I'm reading here or what I've read.

Frequently you've got to maintain the CO2 pressures and concent -- and keep the concentrations down so water alternating with gas or a WAG injection system is used in many of these CO2 fields to prevent CO2 breakthroughs to the reservoir and bypassing oil in place.

Finally, water injection after primary production is required -- once again, we need a water flood, to fill gas

voidage and to increase reservoir pressure at the initial conditions prior to CO2 flooding -- or injection.

So once again, when I first started looking at this I had been told by many people these things aren't going to work in Cook Inlet because we have already done water floods. Well, hallelujah, you've done water floods which a prerequisite to doing a CO2 flood.

The history of CO2 flooding began about 19 -- the mid 1970s in Texas in the West Texas Basin, Permian Basin, and large scale flooding began in 1984. One thing I don't have here as part of the notes, but the CO2 floods are equally effective in clastic and carbonate reservoirs. You don't have to worry about whether you've got a sandstone or a limestone, they work with about the same degree of effectiveness. Many of the reservoirs, for instance, in West Texas are carbonates. We're dealing with clastics up here.

There are currently more than 70 worldwide CO2 floods in operation. A good portion of them are in the United States and in West Texas. Domestically in 2004 which is the last year I have data for, in the U.S.A. CO2 EOR equaled 206,000 barrels of oil per day which is four percent of the total domestic production. In Texas, this is onshore, this isn't Gulf, the rate is 170,000 barrels of oil a day or 15 percent of the State of Texas' current oil production as a product of CO2 floods. This is enhanced recovery due to CO2 flooding. That's becoming

significant.

And as a result of this many other portions of the country are looking at their older fields and saying where can we get CO2 to inject into our reservoirs. The other states that are looking into this right now are notably Wyoming, North Dakota, Oklahoma and Kansas. And there was one I missed a couple of, I think Montana and one or two others.

Internationally the two most prominent examples are the Weyburn field in Canada and the Gullfaks field offshore Norway. The Weyburn field in Canada is a nice one for us to focus on for a minute because they are using CO2 as a byproduct of coal gasification. The Buelah coal gasification plant in North Dakota generates large volumes of CO2. It is actually being piped, I think it's 200 miles north to Saskatchewan where in Canada is using it to increase production in the Weyburn field.

The Weyburn field is 50 years old. It was found in 1954. It has API gravities of 25 to 34 degrees. It has initial oil in place values of 12.4 billion barrels of oil. And the pre-CO2 EOR efforts have produced something in the neighborhood of 350 million barrels of oil or 25 percent of the original oil in place.

They began in the flood process in 2000. They expect to continue flooding for 20 to 25 year life. And they have increased their production from 10,000 barrels of oil per day to 21,000 barrels of oil per day since they initiated the

process in 2000. They anticipate recovering an additional 130 million barrels of oil. They had recovered 350 prior to that and they anticipate recovering an enhanced or extra 130 million barrels of oil beyond what they felt the field would produce without the additional stimulation. And they've doubled their production rate in a period of four years. This is a four or five year old report.

And they're using, again, gas generated from a coal gasification plant as a byproduct of gasification. This is exactly what we'd be looking at potentially using CO2 from -- in Cook Inlet. If Agrium were to build that coal gasification plant they would, again, like I suggested produce something like 100 million cubic feet of gas per day. That gas then could be injected for CO2 recovery process. We use that 7,000 cubic feet of CO2 per barrel we're talking 13, 14,000 barrels of additional enhanced recovery. If I remember the numbers the other day we were talking about Cook Inlet productions now in the neighborhood of 15 to 16,000 barrels a day. This could potentially double the current rate of production in Cook Inlet.

Not only that when you product -- and we'll get -- I'm getting a little bit ahead of myself, but while I'm here I might as well do it. If you produce the oil you're going to recycle some of that CO2 back out, you strip that CO2 back out and increase the amount of injection so you can go from that

100,000 -- or 100 million cubic feet of gas per day to some number greater than that because you're recycling the CO2. So that 13,000 barrels of oil per day we were talking about is not necessarily the maximum you could achieve if you had greater volumes to stick into the ground.

Now if you take a look at the potential application then of the CO2 enhanced oil recovery to Cook Inlet we've got two or three things to keep in mind. This chart basically shows the main oil fields in Cook Inlet in terms of the expected ultimate recovery. The ERR is the estimated remaining reserves. EUR is the estimated ultimate recovery. Excuse me, that first column is produced -- I'm sorry, as a percent of estimated oil recovery. Then the original oil in place estimates and the theoretical based on what we just discussed, CO2 additional oil using that eight to 11 percent range that Nelms and Burke suggested.

And if you take a look at this before we go any further you'd say well, gee, out at Granite Point we could get something in the neighborhood of 50 to 60 million barrels of additional oil. Out at McArthur River 150 million barrels of oil give or take and so on down that line. Ultimately ending up with something like 290 to 400 million barrels of additional oil potentially out of Cook Inlet if you use these numbers without going in and taking a look and seeing whether or not it really applies to Cook Inlet. So your first guess is

we potentially if these reservoirs and oils fit the criteria for CO2 miscible flooding we can get a lot more oil out of Cook Inlet.

Now this right at the moment we are not worrying about -- unfortunately we have to, we're not worrying about economics. We're just talking about the effectiveness -- potential effectiveness of the process.

If you took a look at Cook Inlet and did an initial screening using the criteria that we discussed earlier, this was originally done several -- a year or so before we took a look at it. And Advanced Resources International did a quick and dirty approach to this for the DOE in 2005, their screening process found 12 reservoirs suitable for miscible flooding and one for immiscible floods. They assumed three cases when they were trying to work out an economic scenario for the Cook Inlet water CO2 floods. First case assumed $25 a barrel oil and that CO2 cost $1.25 per Mcf. And this is a CO2 limited situation. They had no ready source for CO2 so they didn't quite know how to play the game. And this case would -- obviously did not fly both because of the cost of the oil and the cost of the CO2 which they still had to come up with a source for.

In the third in- -- second instance they upped the price to $35 a barrel, kept the same price for the CO2 and still had a CO2 limited or nonexistent case, it didn't fly.

The third case used $35 a barrel oil, assumed a source

of CO2 that only cost 75 cents an Mcf, we're assuming that assumption is CO2 generated from the Agrium coal gasification plant, and it flew at $35 a barrel oil.

For two test fields, they only evaluated Swanson River and Middle Ground Shoal. And the obvious reason for that is there is an infrastructure in place to get gas to and from those two fields without having to worry about doing something ever exotic going offshore to McArthur River field and run pipelines and everything out there. These are the two cheapest ones to fly. And they ended up saying they felt there was 140 million barrels of incremental oil recoverable from those two fields using CO2 floods under the case number three. That's not bad.

We looked at it and using very similar screening criteria, came up with the -- basically the same thing, 12 reservoirs that pass the miscible flooding, one that passed -- did not pass and is immiscible, and that would be -- that's the Tyonek B member of the Trading Bay Field, gravities are too high, that's the main problem there. Or gravities are too low, it's a very heavy oil for Cook Inlet.

But you'll note that mainly we're looking at Hemlock and Kenai -- Lower Kenai gasses -- excuse me, reservoirs which is what one would expect.

There's a display of the reservoirs and again, the immiscible flood only in Trading Bay Tyonek reservoir.

We went back and did -- we did not have by reservoir reserves or ultimate oil in -- original oil in place, we have it by field, but not by reservoir. So we use the 25 percent calculation to estimate -- 25 percent of cumulative production to estimate the incremental recovery from the individual reservoirs.

We found six reservoirs and five fields that looked to be attractive possibilities, the McArthur River Hemlock, potentially 133 million barrels of oil. The Swanson River Hemlock, 57 million barrels of oil. Middle Ground Shoal Hemlock, 44 million barrels of oil. The Tyonek in the McArthur River, Granite Point and Trading Bay ranging from, you know, 16 to 35 million barrels of oil. From our -- and that gave us a total incremental increase in oil through CO2 flooding of about 300 million barrels.

Now we looked at this from -- also from the perspective of probably the easiest reservoirs to flood are the Hemlock reservoirs. Hemlock reservoirs tend to be more widespread and continuous and therefore probably more easily flooded by CO2 and not having to worry about the vagaries as much of the channel character of the Tyonek. A lot of the potential reservoirs in the Hemlock are either very tightly stacked channels or perhaps even a alluvial fan deposits which makes them more attractive targets.

The general conclusions then that we'd have in terms of

CO2 flooding, that there are more than 70 CO2 EOR programs worldwide, the process works regardless of reservoir lithology, expected incremental oil recovery is 8 to 11 percent of the original oil in place or approximately 25 percent of cumulative production. I think at point in the Weyburn Field, it's actually 35 percent of the original production that they're looking at because they got 350 to 360 million barrels of production, they're looking at adding 130. So that 25 percent may actually end up being a conservative number.

There are more than a dozen reservoirs, primarily the Hemlock and Tyonek in five major fields of Cook Inlet that passed the screening criteria for miscible CO2 floods. Using the average range of incremental increase in production, 8 to 11 percent, the five major Cook Inlet oil fields have the potential to produce an incremental 290 to 400 million barrels of oil. Using only the major reservoirs within those fields and a 25 percent of cumulative production estimate, the incremental production would approximate 300 million barrels.

To realize an economic CO2 flooding program, the Cook Inlet's oil fields will require oil prices, and this is an estimate admittedly and it may be way off, 45 to $65 range and a low cost, reliable, long term CO2 supply. Remember the original study that was done for the DOE suggested you could do it at $35 a barrel. But we're looking at not just concentrating on the on shore fields, we're looking at the

offshore fields which I'm sure will cost more to do.

With a viable CO2/EOR program in place, the life of the five major fields could be extended for an additional 20 to 25 years and yield oil volumes equal to that of the last 20 to 25 years of production for Cook Inlet. In other words equal to the volumes that have been produced out of Cook Inlet from 1980 to the present. That's a pretty significant number. And so we're potentially looking at doubling in the short-term at least the average daily production rates of those fields if we could find the wherewithal and the resource to do it.

That pretty well summarizes it. Thank you very much.

COMMISSIONER SEAMOUNT: Thank you, David, for some very intriguing presentations. Before I introduce the next speaker just so that maybe this can help you plan your day, we will be breaking as close to noon as we can and probably what that means is the next panel, our New Players in South Central Oil and Gas Exploration, that will probably go both before and after lunch.

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DREW COMER

COMMISSIONER SEAMOUNT: Okay. Our next speaker is Drew Comer, he's a Geologist in Resource Evaluation Office in the Alaska Region of the Minerals Management Service. He has a Bachelor's in Science in Petroleum Geology from Mississippi State University, Master's in Science and Geology from the University of South Carolina. He's worked in Alaska since 1977.

Right now he's working on oil and gas resource assessment of the geologic basins on the outer continental shelf of Alaska. Please welcome Drew.

MR. COMER: Okay. I am with the Minerals Management Service, Alaska Regional Office here in Anchorage in the Resource Evaluation section. I'll be talking today about the undiscovered oil and gas resources of the federal waters of Cook Inlet.

MMS has recently completed a national resource assessment of the undiscovered oil and gas resources. We make a distinction between the word resources and reserves since they aren't discovered yet, and so this is a probabilistic statistical analysis. I'll be focusing on the Cook Inlet area today. We do these national resource assessments every five years, this is for planning purposes and for a resource inventory and to support our five year lease sale schedules. The next five year schedule will go into effect next year so

this is the year that we are doing the national resource assessment.

This is a map of Alaska showing the planning areas of the outer continental shelf. We use these planning area boundaries to limit our assessments. And Cook Inlet, I think you can see in yellow, you know where it is anyway, it's -- this is the smallest OCS planning area shown on that map, but it is important because of the proximity of the infrastructure and the markets here in South Central Alaska.

This is a more detailed map showing the outline of the planning area and the northern part of that area was proposed for leasing in the last five year lease sale schedule. The planning area extends for about 250 miles south of Kalgin Island through Shelikof Strait to the southern end of Kodiak Island. The leases, we've had three previous lease sales with -- where leases were awarded in 1977, 1981 and the last one was in 1997. And there are currently only two leases that are active. We had two lease sales proposed in the last five year schedule, we didn't receive any bids on those. And that raises of question of why there was no interest in the recent sale offerings.

One of the reasons, of course, during much of that time there were lower prices for oil and gas. And in 1997 our last lease sale, that sale unfortunately was limited to the area of north of Anchor Point, it didn't include the high interest area

to the south. ARCO Alaska at one time was very interested in that area, they did a lot of good work in the '80s and '90s and when we had the lease sale we weren't able to offer everything that they were interested in so only two lease sales were picked up in what is now the Cosmopolitan Unit.

Then after company reorganizations ARCO Alaska ceased to exist. Other companies merged and there were different priorities. The larger companies tend to be more interested in areas with a higher upside potential and the smaller companies are pretty much staying on shore where the drilling is cheaper. And if they wanted to drill offshore currently there's no jack up rig or any kind of other mobile drilling platform that they could use. That -- hopefully that will change over the next year. And finally there's a lack of 3-D seismic data in Lower Cook Inlet. A year ago the operators of Cosmopolitan acquired 3-D seismic over that unit, but for the rest of Lower Cook Inlet there's no 3-D seismic which is important for the subtle traps.

This is a map showing the existing oil and gas fields. You've seen this map several times today. This one's a little different, it shows an outline of the Tertiary Basin. Previous speakers mentioned the tertiary period rocks in which the current production is from. And if you -- I don't know if you can see the red line south of Kalgin Island that separates the boundary of state waters and federal waters, but if you can you

notice that very little of that Tertiary Basin extends down into federal waters. The Cosmopolitan Unit is shown there, it is mostly in state waters, but two leases are in federal waters and they'll be the first production from the federal OCS in Cook Inlet.

These are currently the only two active leases and below that you'll notice that there's over 3 billion barrels of oil and over 8 1/2 trillion cubic feet of oil -- of gas discovered to date. That's ultimately recoverable and most of that has already been produced.

Next I'm going to show a location map of a geologic cross section through some of the exploratory wells that illustrates an important feature of the architecture of the basin. The federal OCS is outlined in blue, you might be able to see the lease tracks grid in that area. The well locations are shown in red, all of the outer continental shelf wells except for one drilled in Shelikof Strait are on that map. And there's a line in magenta that extends south to north, that's going to be a stratigraphic cross section I'm going to show through those wells. It ends at the Cosmopolitan Unit at the discovery well on Cape Starichkof.

And the feature of significance is the Augustine-Seldovia arch which extends from Augustine Island eastward to the southern Kenai peninsula and the Seldovia area. That arch runs transverse to the normal structural fabric of the basin.

As you saw in earlier talks everything pretty much runs north east, south west, parallel to the mountain range that confine the basin.

And this is that cross section, it's about 75 miles from south to north. On the north end to the right that's the Starichkof well which was the discovery well of the Cosmopolitan Unit. That well was drilled in 1967, it wasn't developed for a number of reasons that I won't go into here. But if you notice sea level, the horizontal line, below that is -- in clear is tertiary non-marine sedimentary rocks where the production in Upper Cook Inlet is and the Hemlock conglomerate is shown in orange. That's responsible for over 80 percent of the oil production in Upper Cook Inlet.

And below that, the lower tertiary un-conformity above that green formation, that separates the rocks of the tertiary non-marine above from the Mesozoic era marine rocks below. And at the Starichkof well, that's at almost a depth of 9,000 feet.

The tertiary rocks get to be over 25,000 feet in the deepest part of the basin, but going south you see the Augustine-Seldovia arch and that -- three wells from the left, that's the south archway right at the crest of the arch. And the tertiary there is about 1,000 feet. And it gets a little deeper, about 3,000 feet to the south of there, but it never gets thick again, the tertiary sediments do not.

So the producing formations in Upper Cook Inlet are

just too shallow throughout most of the federal water to be prospective. And we don't have the gas play to nearly the extent that they do in Upper Cook Inlet.

The dry gas, which was mentioned in earlier talks, that non-associated gas occurs in a play and most of it, over 90 percent of it, occurs from 3,000 to 5,000 feet. That just happens to be the depth at which the methanogenic (ph) bacteria can generate methane out of the carbon in the coal beds and the highly siliceous (ph) silt stone that occur in those tertiary non-marine sedimentary rocks. If you go to the left of there then you can see that you're in that green section, Kaguyak formation, it's a Late Cretaceous age formation. It doesn't have the coal beds or the highly carbonaceous (ph) siltstones that can provide a source for methane generation. So we -- our dry glass play in Lower Cook Inlet is much more restricted than in Upper Cook Inlet. We do have the oil prone source rock in the Tuxedni group there, that was mentioned in earlier talks as a oil generator. It's in tan on that if you can't read the writing there.

Finally, I want to mention something about the petroleum play, we start with this when we do our resource assessments. It's beyond the scope of this talk to go into any kind of detail on the assessment methodology that MMS uses. But we start with the petroleum play which for a working definition we define as geologically related prospects with

similar hydrocarbon source rock, reservoir rock and trapping mechanism. And we do have the oil prone source rock in Lower Cook Inlet. We don't have very much of the gas prone source rock. Reservoir rock has been a problem in the Mesozoic section, but where there's a thick enough tertiary there's good reservoir rock.

Trapping mechanism, there we're talking about either a structural trap such as a incline or a fall trap or a stratigraphic trap which would be a porous sandstone bed encased in impermeable shale for instance. That's a very subtle trap, it's difficult to explore for and as Dave Hite mentioned earlier, it's -- that's an under explored concept in all of Cook Inlet, both Upper and Lower.

Using that working definition we've defined four plays for the federal OCS in Cook Inlet. First, is the tertiary oil play which occurs in the northern part of the federal waters. This is a continuation of the oil play of Upper Cook Inlet, same source rock, same reservoir rock, it just happens to be limited to a fairly small area. That's only about 825 square miles out of a total 8,400 square miles for the entire planning area.

Next is the Mesozoic stratigraphic play. This play involves mostly Cretaceous age sandstones trapped in shale. This play is -- will be best developed on the western side of the basin extending all the way down -- pretty much down the

limit of the basin. Kodiak Island and the Kenai Mountains and Chugach Mountains were not emergent throughout most of the Mesozoic so that would have been a very deep water area. So that's -- for that reason we think the sandstones which could create the reservoir rocks were probably coming off the mountains to the west.

None of the wells shown on there targeted stratigraphic traps even though they happen to be within that play. So that is again an under explored concept in Cook Inlet.

Next is the Mesozoic structural play. These involve the same age rocks, probably cretaceous reservoirs, cretaceous sandstones and this pretty much covers the entire planning area. Basically you can get fault and anticlinal (ph) traps anywhere in the basin. This is the play that was explored in previous efforts in federal water. There are 10 exploratory wells indicated there, all of them targeted a structure. There were no discoveries, but three of them had very good oil shows, the three northern most wells, two of which -- drill stem tests were run. They did recover good quality oil, but the flow rates were too low. The key to finding a trap here that's viable is to find sandstone, you can't just find the trap, you have to find the reservoir.

And, finally, there's the tertiary gas play. This play basically overlies the tertiary oil play in the same general area. It's restricted to the northern most part of the area

where the tertiary rocks are 3 to 5,000 feet. And it's -- that's basically north of the Augustine-Seldovia arch.

Now we use geologic data from all of these plays to construct statistical analyses of a number of variables, I'm not going to go into any of that, but then we do a probabilistic estimate using our computer model and here are the results for Cook Inlet.

This is for the oil play potential, I'll talk about oil first. And these numbers are in millions of barrels and what is shown there are two columns, the first is technically recoverable. And now let me point out that this is the mean of the distribution and the mean is not the right answer or the only answer, that just happens to be an average of 10,000 computer iterations. So there's a wide range of possibilities and this is the average of all of them. And you can see that the highest is 349 million barrels in the Mesozoic stratigraphic play. And those oil plays are pretty close and then the tertiary gas play obviously doesn't contribute any oil. It also doesn't contribute condensate because it's a very dry gas.

And these plays total up to about 1 billion barrels of oil that -- technically recoverable. That compares to over 1.3 billion barrels already discovered in Upper Cook Inlet, not counting what's undiscovered there.

The right column is economically recoverable oil.

There's not a big difference between those two numbers for Cook Inlet because we are close to infrastructure here so most of what you find here can be produced if the price is reasonable. This price is estimated at $60 -- these numbers are estimated at a price of $60 a barrel. Now in today's paper the price for oil happens to be within $1 of $60 a barrel. We didn't predict that and we can't predict the price of oil or gas any better than anybody else, but we do have to make certain assumptions and I'll address that issue later.

But first let me show the gas play potential. Again this is in the mean and it's a trillion cubic feet. And as expected the play for the tertiary gas play contributes by far the lion's share of the gas to this basin. The three oil plays, basically that's solution gas that would come out of the oil when it is produced. And total it up and you get about 1.2 trillion cubic feet technically recoverable. That compares to over 8 1/2 trillion cubic feet for Upper Cook Inlet already discovered.

Economically recoverable is in the right column and that -- there's not a lot of difference on that, 1.1 Tcf. Now the assumption here is at $9 per Mcf, that's a lot higher price than we have right now, but it's a price that has occurred in the not too distant past.

Now we cannot really predict what the price is going to be and we recognize that and for that reason we construct a

price supply curve. And I don't know if that shows up very well, but first I'll focus on the oil, that's the green line. And I mentioned that at $60 a barrel 923 million barrels could be produced. The billions of barrels is on the bottom of the graph and dollars per barrel is on the left column. Now if the price of oil dropped to $30 a barrel then only 520 million barrels of that would be economically recoverable. And if it dropped below about $20 a barrel, then very little of it would be economically recoverable. And regardless of how high the price goes, the curve peaks out above about $70 a barrel so that it doesn't matter what the price is, there's no more oil in the system.

Likewise for gas, the -- which is the red curve of the price supply curve. The supply in Tcf is read on the top and price per Mcf on the right. And at $9 an Mcf, about 1.1 trillion cubic feet could be recovered economically. And if the price dropped to $4.50 per Mcf then only about 640 billion cubic feet, that's .64 Tcf, would be economically recoverable. That compares -- that is approximately three years of usage of -- current usage of Cook Inlet. And below about $3 an Mcf very little of it is going to be economically recoverable. And the curve peaks out above about $10 an Mcf so that no more gas is available regardless of what the price goes to.

Now I mentioned these are the mean case numbers and the mean of the distribution is just the average of 10,000 computer

iterations. We can also construct a low case scenario and a high case scenario. The low case means the chance of success here is 95 percent and for gas and oil those are very small numbers, you can ignore those. And then the mean I've already reported.

But on the right is the high case scenario at 5 percent chance of success you could get almost 3 1/2 trillion cubic feet of gas and 2.85 billion barrels of oil. That high case potential isn't real great for a basin which is probably why the larger oil companies don't get real excited about Lower Cook Inlet because the up end potential just isn't what they like to see.

In addition to Cook Inlet MMS Alaska's made estimates for all of the outer continental shelf basins for undiscovered oil and gas resources in this 19 -- in this 2006 national assessment and we're reporting these on line right now. And the next slide will be a comparison of these basins for the oil potential. I don't know if you can read those numbers, but basically the first one, the winner of this contest is the Chukchi Sea at over 15 billion barrels of oil. The Beaufort Sea is next at 8.2 billion barrels. And it's understandable that the Arctic basins is going -- those basins are going to have the best potential. And then there's a big drop off down to Cook Inlet at 1 billion barrels, but Cook Inlet at least comes in third on this curve. The Bering Sea basins tend to be

very gas prone, the Gulf of Alaska didn't pan out too well, Kodiak shelf has very low potential so Cook Inlet at least comes in third there.

Now for gas it's a different story. Chukchi and Beaufort still come out number 1 and 2. The Chukchi Sea at over 76 Tcf of gas technically recoverable, that's a very high endowment, there's a lot of unexplored potential in the Chukchi Sea and the Beaufort again is high. But Cook Inlet drops off very, very low in this because the gas play area just covers two small an area for that potential to be high.

But in third place there's the North Aleutian Basin. And that one's kind of interesting because it's not too far from here, it's about 500 miles to the southwest. This is the federal waters portion of Bristol Bay in southwest Alaska. We had a lease sale here in 1988, but Interior had to buy back the leases, there were a lot of objections at that time by the state and the local governments and the area was under congressional moratorium for a long time. That moratorium has been lifted, it's currently under a presidential withdrawal status, but that possibly could change over the next year or so.

Here is the results for North Aleutian Basin, totaled up all the plays. The gas potential is not real high so ignore that, but look at the -- excuse me, the gas potential is real high, ignore the oil. The gas at 8.6 Tcf mean technically

recoverable. But the high case scenario over 23 trillion cubic feet. That's a good high case scenario for gas potential for the North Aleutian Basin.

And finally we have our five year lease sale schedule in draft stage, this is what it looks like. This will probably be finalized in March or shortly thereafter. It's dominated by the Arctic sales, the Chukchi Sea and the Beaufort Sea, but we do have two Cook Inlet sales in 2009 and 2011. Those are indicated as special interest sales. What that means is since industry didn't have interest the last time we offered this area, this time they can indicate which specific blocks that they would like to bid on and then we can have a sale on those blocks. If none of the companies indicate interest then the process stops there and we'll canvas the industry on an annual basis to see once again if they have interest.

The North Aleutian Basin sales are there at 2010, 2012. I've got them in question marks because it is, you know, a presidential withdrawal status, but that could possibly change when this five year schedule is finalized.

In conclusion, I'd like to say that we have about 1 billion barrels of undiscovered oil, technically recoverable in Cook Inlet planning area and possibly 1.2 trillion cubic feet of undiscovered gas. The Cook Inlet lease offerings are going to be in 2009 and 2011 and we see a very high gas potential in the North Aleutian Basin. Now to get the results of all of

these studies, the numbers that I've given you in a lot more detail and detailed write up of the plays and the provinces of the Alaska outer continental shelf you can check out our website at mms.gov/alaska gets you to the Alaska's portion of it and to the resource evaluation section where all of these numbers and write ups will be. Thank you.

COMMISSIONER SEAMOUNT: Okay. Thank you, Drew, for a very informative -- very valuable information. In fact, I'd like to thank the whole panel for providing us with some intriguing possibilities among other things.

Okay. Let's take exactly a five minute break while the New Players -- the people on the New Players panel that want to come up here and keep me company, that's fine. If you want to sit back there so you can get a better view of the show you can wait until your presentation comes up, but you're all welcome to join me up here. And we're going to start in five minutes with Corri Feige representing Storm Cat.

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(On record)

DENISE STONE

COMMISSIONER SEAMOUNT: Okay. The break is fast approaching an end. We're now in the panel of New Players in South Central Oil and Gas Exploration. Our first speaker is Denise Stone. She's a petroleum geologist currently serving as exploration advisor for Alaska for Benchmark Oil & Gas. Denise is a graduate of Valdez High School in Valdez, Alaska.

Following high school she earned a Bachelor's of Science and Geology from Texas Christian University in Fort Worth, Texas and a Master's degree in Geology from Memphis State University in Memphis, Tennessee. Denise worked for Unocal, Superior Oil, Mobil earlier in her career and of late she has spent 18 years at AMOCO and BP. She has been a consultant since 2003.

During her career she has worked mainly international exploration and production projects, these include areas of the North Sea, East Africa, the Gulf of Suez, Egypt, Columbia, Trinidad and the Rocky Mountains. Denise is active in several industry organizations and is past president of the Houston Geological Society. She currently resides in Houston, Texas. Let's welcome Denise back to Alaska.

MS. STONE: Thank you very much, Dan. I first came to Alaska in the mid '70s, my dad happened to be a project manager for Alyeska at the time and you know what Alyeska was doing back then. I was a junior in high school, about to begin

my senior year and moved to Valdez. And during that year, my senior year of high school, something very profound happened to me that would stay with me for the rest of my life and that was that I became extremely interested in geology.

Valdez, many of you I'm sure have been there, it's a beautiful place and the combination of the high mountains and the deep water port and all of the scenery there is just magical. So when I got to the university I pretty knew I wanted to study geology. So thank you for that, Alaska, and I feel like, you know, if it wasn't for that experience I may not be here today talking about exploration. So it was my predecessors in my profession that founded Prudhoe Bay that kind of brought me full circle here today.

So, you know, with that as a short introduction I wanted to come today and tell you a little bit about Benchmark Oil & Gas, who we are and what we're trying to do in our entry here to the Cook Inlet. Traveling with me here from Houston is Andrew White, our attorney landman. Andrew, you want to take a bow there. Andrew and I will be happy to answer any questions that you have about Benchmark and we'll be around for the rest of the day today so, please, feel free to come up to us and talk to us about any questions you might have.

Yesterday's message was very powerful. I left here with a smile on my face thinking wow, you know, this is a tremendous place to explore because everybody is so gung ho and

bullish on getting wells drilled and finding more resources. And there aren't very many places in the world that welcome oil and gas companies to the extent that Benchmark and I personally feel welcome here. So thank you very much for that.

Some of the things I heard yesterday, encourage additional E and P in the Cook Inlet, promote more exploration for gas, the greatest need is exploration, new incentives now exist for greater exploration and this morning I was hearing there's still plenty of opportunities for exploratory drilling. And I also heard from David Hite about the missing fields. So we're here to make a really good attempt and hopefully we'll be successful at finding those missing fields.

Benchmark is a new player in the Cook Inlet Basin, we believe significant resources still exist there, we've come to explore for them.

I have an outline of what I'd like to tell you about. Over the next few minutes I'm going to talk about Benchmark in Alaska, our Cook Inlet acreage position and what our strategy is to date, who we are generally, our current activity elsewhere, our leadership and I'll provide a little bit more -- or a pathway to some more information about us if this just gets your appetite going and you'd like to know more.

This graphic right here is a histogram, it shows the results of the lease sale that just happened in May of this year. We were both surprised and delighted to see the results.

Surprised mainly because there weren't too many oil companies going directly for bids in this area and we were delighted because we got 20 out of the 22 tracks that we applied for. So we were really happy. In the conference room that day when we learned the news everyone was smiling and thought well, this is super.

There were 16 participants, they're listed on the bottom axis of the graph in alphabetical order. Benchmark was the most active and on the left axis are the number of tracks won so you can see we had a high of 20 and we're there in the red bar. We had a high of 20 and the total cost of our bids was just over $1.2 million.

Okay. The total tracks in terms of acres were 110,000 acres. The map on the right shows these tracks that Benchmark won. And also shown are the existing oil and gas fields in the basin. Benchmark tracks are shown in brown. Our strategy at the moment is to focus on the Cook Inlet and more specifically on shore in the Kenai Peninsula. These tracks cover roughly three areas, the first one is a north coast group of tracks, the second is two in the central Kenai area and then the lower or the southern group, we call them the North Kachemak Bay blocks.

We intend to explore by acquiring data, we're in the process right now of acquiring or trying to get access to well data, existing seismic and also potential fields data. We want

to evaluate the work already done in the basin and apply new technology to identifying drilling prospects that we would like to pursue.

The exploration hiatus that took place in the '70s, '80s and '90s is also a technology hiatus and we want to test new ideas and apply some technology that has not been brought to this area over the last 30 years or if it's been brought it's been brought in a limited way.

We intend to conduct our business with respect and sensitivity to the environment and in compliance with all current environmental laws and regulations.

Benchmark looks forward to doing business in Alaska as long as the business climate is good for independent oil and gas companies and we welcome those companies that might consider working with us as partners on the hunt for more resources.

I have with me a handout which -- I have a healthy stack of these, they're not -- I don't have enough for everyone, but if you would like one you can come up after. It shows the map that is featured in the current slide along with some of the main points that I'm making today so feel free to come up after.

Okay. Who are we? Benchmark is a 100 percent upstream exploration and production company. We're in a growth spurt right now. We like to operate and we like to drill wells. We

are Houston, Texas based and we were founded in 1976. We went public on the NGM exchange which is the Nordic Growth Market. And that's an equities market that trades in Finland, Norway, Sweden and Denmark. And we went public there in June of 2006 which is just not too long ago, a couple months back. Our parent company is Benchmark Oil & Gas AP, which is headquartered and located in Stockholm, Sweden.

Current areas of activity, the white stars on this map show the location of Benchmark's current areas of focus. You can see the Cook Inlet there with a white star. Our core area of drilling and field development at the moment is on shore Texas in Orange, Lavaca, and Liberty counties. And we also have active properties in the San Joaquin Basin of California. Currently we're looking at new opportunities for business in both Argentina and North Africa.

In 2005 Benchmark drilled 10 wells with a respectable success rate of 90 percent and we're very proud of that. And this year we plan to drill 12 wells and to date we've drilled five of those and four have been successful. So we've got a bunch of drilling to do before now and the end of the year as you can imagine to meet the goal of 12.

This is a photograph of our board of directors. We have a very international group of directors with multiple nationalities and professions represented, namely Poland, France, Sweden, Egypt, the United States. Many of these folks

have background in mining and finance. As you know Sweden is a big area of mineral resources as well. In fact, there's a lot of parallels between Sweden, not just latitude, but mining wise and natural resource wise. Unfortunately don't have hydrocarbons in abundance in Sweden, their -- I guess the geology of the Scandinavian area unfortunately didn't bless Sweden with the oil and gas that Norway and the UK have in the North Sea, but they are nonetheless very interested in oil and gas investment.

Many of you may have met Robert Pledger (ph), he's on the top row, third to the right. Robert's the co-founder of Benchmark, he and his wife started the company in 1976 and he has a very strong business and geotechnical sense. He is the one that I would call the greatest champion for Alaska and it's delightful to work for him because he has so much energy for this project.

Everyone pictured here is really delighted to be doing business in Alaska and they look forward to good relations and success in the future in the Cook Inlet.

For more information about us you can write to us if you want, you can go to our website, give us a call, whatever you prefer. Benchmark's website is benchmarkoil.se. You'll find it's all in Swedish or last time I looked at it was all in Swedish, but we have efforts under way, great efforts, to have an English version ready momentarily, we've been promised.

So it's -- they're doing that in Stockholm and shortly you should see English. Also you can find information about us on ngm.se which is the Nordic Growth Market I spoke about.

And we look forward to getting to know many of you and working together in the future. And, you know, before I just want to make one very important acknowledgement and that is that, I guess, around two -- year and a half, two years ago, when Benchmark started to get interested in Alaska and they were hearing this call for explorers that you folks have been putting out, trying to get companies interested in the Cook Inlet and other parts of the state. We came in contact with really great folks from the State of Alaska, Department of Natural Resources, many of whom are here today. And if it wasn't for those folks coming down to Houston and being at AAPG, the American Association of Petroleum Geologists conference and also NAPE which is another big one, the North American Prospect Expo, if they hadn't come and really told the Alaska story as clearly and as nicely as they did, I really don't think Benchmark would have participated as aggressively as we did in this lease sale.

It -- you know, the state of Alaska folks provided us the way to the web and the data, how to access information that in the old days would take forever to access and become familiar with. So thank you very much for that, we appreciate it and we look forward to success in the Cook Inlet.

COMMISSIONER SEAMOUNT: Thank you, Denise.

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KEN SHEFFIELD, JR.

COMMISSIONER SEAMOUNT: Our next presenter is going to present on behalf of Pioneer Natural Resources Alaska, that's Ken Sheffield. He has a Bachelor's of science in Petroleum Engineering, another one from Texas A&M University. He's -- as I said he's president of -- he's been president of Pioneer Natural Resources since 2003. He's had various positions as vice president.

Well, there's -- he was president in Canada from 2002 to 2003 and before -- and since -- from '97 to 2002 he was a vice president in Canada and the Gulf Coast division. From 1982 to 1997 he had a number of other -- he was vice president of MESA, Incorporated, Acquisitions and Development, as well as a number of other positions.

His professional affiliations are -- he's a Resource Development Council Board of Directors, he's on the Board of Directors of Alaska Clean Seas, he's on the Board of Directors of the Alaska Oil & Gas Association and from 2000 to 2002 he was on the Board of Governors for the Canadian Association of Petroleum Producers. With that we'll welcome Ken. I know Pioneer's been around for a while, at least two years -- two or three years, is that it?

MR. SHEFFIELD: Three years.

COMMISSIONER SEAMOUNT: Three years. Okay. So let's welcome Ken.

MR. SHEFFIELD: Good morning. My name is Ken Sheffield, I'm President of Pioneer Natural Resources Alaska. And thanks to the AOGCC for organizing this fine event and for the opportunity to speak today.

Pioneer only has one project in South Central Alaska so in my brief comments today I'll give you an overview of Pioneer as a company, just a quick look at that, then a look at our Alaska strategy and history which is now about three years old, and then finally a look at our Cosmopolitan project in the Cook Inlet.

The first slide that you see here shows that Pioneer's an operator not only in North America, but also on the African continent. We have reserves of about 865 million barrels. Our current daily production is about 99,000 BOEs per day. We have a long life resource with an enviable R to P ratio of about 23 years. We have a number of new growth areas in the company, specifically in the Rockies, in Mississippi, in Canada, south Texas and also here in Alaska.

Our team in Alaska is working hard to establish Alaska as a core producing area for the company. And to achieve that our goal is to become the best new project delivery team in the state. And toward that end we've organized an outstanding staff here in the state, we have 31 employees here in Anchorage. We're making good progress toward producing, reducing the cycle time on projects.

We're maintaining a balanced portfolio of near term and long term projects and we're working hard to become a partner of choice here in the state. We've built our portfolio very rapidly over the last three years starting in 2002 with Oooguruk, 2003 with Storms and the following year we made our investment in NPRA and in 2005 we took an interest in the Cook Inlet with the Cosmopolitan property.

This slide outlines Pioneer's acreage position in Alaska. We have an interest in 1.7 million acres in the state, most of that is on the North Slope. Our cornerstone project is our Oooguruk discovery that you can see just north and west of the giant Kuparuk field. We also have significant exploration acreage in the central North Slope and out in NPRA we're a 20 to 30 percent working interest owner with our good friends at ConocoPhillips and Anadarko. And if you look at the top right of that slide the inset, you can see that we have a 50 percent interest in 25,000 acres in the Cook Inlet around that Cosmopolitan discovery and Pioneer recently became the operator of that unit.

But before we get onto the Cook Inlet, I'd like to talk just for a couple of minutes about a project that's really on the go. Pioneer is out there making things happen. This is our Oooguruk project. As I said it's the cornerstone that we're building our business in Alaska. This project is expected to deliver about 15 to 20,000 barrels a day, first

production is scheduled for 2008. The project is very much on schedule.

In the first half of the year we mined and hauled gravel to build the gravel island that you see a picture of. In the second half of the year we've been working on a number of things as well. The contouring of armoring of the island with those 13,000 pound gravel bags was completed last weekend, so if you were to see it today you'd see those white gravel bags armoring the island, completely surrounding the island.

We're quite busy getting ready for the winter construction season, procuring equipment and services. We're procuring things from all over the world, from Argentina to Norway, the U.S. as well. We're busy fabricating modules. Many of the modules for this project are being fabricated right here in Anchorage, Alaska at the ASRC yard. Some of them are being fabricated down at ASRC's yard in New Iberia, Louisiana. We're also modifying a Nabors drilling rig that will go out onto the gravel island in 2007.

This next slide is an artist's rendering of what our project will look like next summer. With the drill site facilities installed, with the subsea flow line installed, with the Nabors rig installed on the island and drilling and the connection made back to existing facilities at the Kuparuk River Unit. So we are out there making things happen.

Now I'll talk for just a couple of minutes about our

only asset in South Central Alaska, that's our Cosmopolitan Unit. This is a known oil discovery as one of the previous speakers mentioned. It is very much in the appraisal phase. Pioneer is the operator with 50 percent working interest. The accumulation is about two miles offshore, near a place on the lower Kenai called Anchor Point. The resource potential here is fairly large, 30 to 100 million barrels and we've been the operator of this, taking over from ConocoPhillips since June and we've got our legs under us and are really pushing this project forward. And we're envisioning that if all goes well you could see first production in approximately 2010.

This slide gives you an overview of the Cosmopolitan property, it was discovered way back in 1967. ConocoPhillips and its working interest owners drilled a long reach appraisal well in 2003, tested the Hemlock on an extended test approximately 500 barrels per day. Pioneer became involved in this project in 2005. ConocoPhillips as the operator at the time procured a new 3-D seismic survey late in 2005. The resource has oil in both the Hemlock and Tyonek intervals which as several speakers have demonstrated, there's analog production from some very large fields in the Cook Inlet.

I mentioned that it's two miles from shore which is certainly a challenge. It's -- we're very conscious that it's in an environmentally sensitive area. We -- we're not blessed with a great reservoir description just due to the lack of

data. The initial 2-D seismic was of relatively poor quality, there have only been a few penetrations in this things so our well control is limited. And that was the reason that the working interest owners got together and shot this new 3-D seismic survey. With that new survey we have a much better handle on the shape of the structure and the size of the resource.

If all this were to come together, our appraisal was successful and we decided to move forward, it would require some pretty significant infrastructure to bring this crude to market. We're about 65 miles from the existing Tesoro refinery on the Kenai peninsula.

And my last slide is what our go forward plan is for Cosmopolitan. It's pretty simple, we are working with the working interest owners to plan and drill and drill and test an appraisal well sometime in 2007. Once that well is drilled and tested we'll evaluate the well results. If they meet a certain criteria we'll define the development strategy, a lot of engineering will need to take place in order to put a project like this into high gear and then once the engineering's done and we have all the cost data in, all other evaluations done, we would jointly with our working interest owners make a development decision.

So I appreciate your time and attention today and enjoyed visiting with you. Thank you, Ken.

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Congratulations on your going and successful program.

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A.W. "BILL" RUTTER, III

COMMISSIONER SEAMOUNT: Our next speaker is Bill Rutter III. He's speaking for Rutter and Wilbanks. Bill Rutter III graduated from the University of, where else, Texas at Austin.

You know, I hear about your team every day from our third commissioner, who's also from the University of Texas at Austin. And I'll tell you what, that sounds like a really good football team with a prolific petroleum engineering department.

MR. RUTTER: You've got that backwards.

COMMISSIONER SEAMOUNT: Okay. All right. Sorry about that. But he graduated from the University of Texas at Austin with a B.A. from the Plan 2 Honors Program in 1975. In 1981 Bill joined the family oil and gas company, Rutter and Wilbanks Corporation as a third generation oil man doing land work until 1989. And when I call Rutter and Wilbanks and ask for Bill, they always ask me which one.

In 1989 Bill established the seismic division of R&W, a company called Towhee Exploration where Bill spent 10 years as chief geophysicist. In 1999 Towhee -- isn't that a bird?

UNIDENTIFIED VOICE: Towhee.

COMMISSIONER SEAMOUNT: Towhee. Okay.

UNIDENTIFIED VOICE: It's a bird.

COMMISSIONER SEAMOUNT: I used to be a bird watcher, too.

In 1999 Towhee folded and Bill concentrated on screening and generating deals at R&W and heading up the fund raising arm of the company. Since 2000, Bill has founded a number of ongoing concerns, including a geothermal company, a company developing a continuously variable transmission, an energy technology incubator, and a large municipal water supply company.

Bill is manager of R&W's extensive Alaska assets, which include large leaseholdings in the Copper River basin, the Cook Inlet basin, and the foothills of the Brooks Range.

Let's welcome Bill.

MR. RUTTER: Thank you, Dan. It's a pleasure to be here. Rutter and Wilbanks is celebrating its 70th anniversary this year. My grandfather started the company in 1936 down in Midland and in El Paso, Texas, and we've had a pretty good run of it.

We've been in Alaska for about three years now. We first got our feet wet by farming in a large block of acreage where we owned an over-ride that we had bought from Anschutz. Anschutz and Forest had a large tract of land referred to exploration license number 1 from the State, and it is out to the east of here at Glennallen. Glennallen is kind of the center of the thing. And we saw some real potential there for mostly gas. We figured it was a gas basin, and, you know, who in their right mind go chase a stranded resource in the middle

of Alaska. Well, Rutter and Wilbanks would.

And so we put a project together. I'm going to talk about that project first, then the Northern Lights project down here in the Cook Inlet waters, and then the Eagle and West Eagle projects which are on-shore Kenai. So these are the three that we're doing that are germane to the South Central discussions here.

In Copper River Basin, as I said, it was a farm-in from Anschutz and Forest. We defined a good show with gas with a 3-D -- I mean, excuse me, a 2-D seismic program. It seemed like the most cost effective way to define a drill site. We then drilled a well to 5,000 feet, had a tremendous amount of trouble doing so, and I'll go a little bit into that. And currently as in today, we are out there completing it. I had hoped to have some indication of what we've found but that will be tomorrow probably.

Anyway, here's a map of, I don't have the scale there, but those blocks represent townships, not sections. It's a pretty large acreage of block in red that was our A.M.I. That's been contracted to where we've bought some leases from the State and from the Ahtna Tribe, and a few other people that have minerals out there. So far we haven't nominated any federal acreage, but I think there's some prospective there.

This is the layout of the seismic that was both already available in the red dotted lines. They're a little hard to

see, but it's a north/south/east/west grid of existing 2-D shot by AMOCO in the '70s. And we can back in, and I don't have a pointer, but towards the southeast end of that southwest/ southeast seismic line, is a well called the AMOCO -- or, excuse me, Pan Am, now known as BP, got run my trap there. That well had some shows and we were trying to figure out to get hide of that. Well, we shot a program and showed that we could get about probably 2200 feet high to that well, which, where we're from, that's a good place to drill a well, 2200 feet high to a show. And the well -- the green vertical line to the right is the actual Moose Creek well.

Those other two green vertical lines, unfortunately, look the same as well penetrations. They're not. They're where we tied the other two lines that we shot. So ignore those.

But we did drill up on that very large structure. It's a very interesting structure, and at about 1700 feet where we set our first main string of casing, we could not get out from underneath that due to high pressure. We encountered unbelievable pressure very shallow in that well. They had had some pretty serious pressure at the Moose Creek well back in the '60s, and it was very problematic.

But we ended up drilling most of that well with 20 pound mud. Now, the engineers in here would say that's impossible, but it wasn't impossible, just expensive. And we

lost the hole at one point, had to sidetrack it. We spent an unbelievable, maybe a record amount of money drilling an on-shore 5,000-foot well. And the pressures that -- or the mud weight that we had to use and just the way the deal worked out, we've pushed mud back into that porous formation where we think our reservoir is some unknown distance, but it's a lot further than 28 inches, which was the maximum we could perforate using conventional perfing technology.

So the well remains untested. It was drilling about a year and a half ago, and we're out there with a quill (ph) tubing unit doing a perf drill where we're actually drilling through the casing with a small drill and drilling out past the formation damage. And we hope to have a gas discovery.

There's a wonderful picture, it's now my screen saver on my laptop, of the location during the wintertime. This was taken in about March, with the Wrangell Mountains in the background.

The marketing options, should we make a discovery out there are sort of the main point here, and it's going to be determined by the size of the reservoir or the resource that we're able to establish. If we have a marginal 3, 5 Bcf well, something like that, it will nicely satisfy the demands for the Copper Valley Electric Co-op, and they are very eager to switch over from diesel to natural gas, which would require a small eight mile pipeline, low pressure line into town for them to

generate electricity. And I think that whole sector of Alaska is really pulling for this success here. And it would also satisfy any residential needs in Glennallen.

And the Ahtna Tribe is actually quite interested. They've got quite a few prospects that we've generated there on them, and it will mean a lot more activity for them. So in terms of economic development, it's the biggest thing to hit Glennallen ever. Well, since the highway was built out there.

If we make a big discovery, say we prove up hundreds of Bcf or more, and there's certainly the potential there for that, the spur line seems to have some legs going that direction. Harold Heinze has been pushing that pretty hard I'm not sure that's the route it's going, but we might have something to say about that if we can prove up a large resource that way. And what that could mean is while we're waiting for the North Slope line to be built, the spur line in the next 15 years while we're waiting could satisfy some of the demands over here. If we can prove a large resource, it might be the catalyst that gets the spur line built or the spur line concept gelled. It satisfies my problem of marketing the gas.

It also creates another problem for me which I'll go into later that has to do with saturating the market here with gas and wrecking potential to explore around here for gas. That's an ongoing discussion. It will be interesting to see how that develops.

You know, in the absence of the spur line, we could have -- or we certainly have the possibility of building our own gas line, making a deal with someone like Agrium or Chugach or your metropolitan power, whoever, you know, might be interested in inexpensive gas reserves, because they are stranded, and, you know, to monetize them is going to take some money, and I think they're not worth -- they're certainly not worth $5 a thousand.

The Northern Lights project is what was referred to originally as ARCO's Sunfish project. We through my friend Mark Landt found out about this project, and we ended up buying this from a company called Prodigy. And it's basically all of the saddle acreage, you know, which a geologist would say, boy, what a bunch of dummies. They bought all the low acreage between two highs on the end of an anticline. Well, ARCO, as Bill Van Dyke pointed out yesterday, did some great science out there, and I would agree with Bill's assessment.

I think there's a lot of oil in this structure. It's a very large structure. It's about 100 square miles. It's had 16 penetrations, and in our opinion 15 of them proved commercial at these prices. Certainly not at $10 oil, but at 60 or $70 oil they're highly economic. And we control a good piece of that anticline. The north end of it is the North Cook Inlet unit that ConocoPhillips operates as a shallow gas field, and underneath that there's some proven reserves in the Tyonek

and Hemlock. That's the targets we're looking for. It's strictly an oil play for us. We see the oil as highly as high monetizable, the gas much less so. And the south end of the anticline is controlled by Forest Oil.

Now, further south as you step on down perhaps through a series of uneschelon (ph) blocks to the south, you come upon the Kitchens and East Kitchens projects that Escopeta is planning to drill. And, of course, this is out in the water. It will require a jack-up rig. We're hoping that Dana Davis can do what he says he's going to do and bring that rig in here. In the absence of that, we're going to have to figure out how to do that ourselves, but I don't see that as an impossibility. I think there's enough interest in the world to make that happen. Mark Landt may talk a little more about that later.

On this -- I'm going to use this map to discuss one other thing. There's been -- I agree with Mr. Hite in that the remaining potential in this basin really is the stratigraphic opportunities, not the structural. Most of the structures have been drilled and most of them produce. The remaining potential really is the stratigraphic nonconventional, or nonstructural type production. And on the flanks of this structure, and on some of the further out areas around away from the platforms, there is oil in place. There's oil and probably plenty of gas as well. And one of our strategies has been to pick up acreage

out in the water on the flanks of some of these structural fields with the idea that if we do get a jack-up rig in here, we'll be able to access that oil, and we'll be able to explore for some of these nonconventional opportunities. And, you know, I think we'll be concentrating on oil. I think there's a lot more oil to find here.

And I agree a lot with what was said today. I'm not sure I agree with a lot of what was said yesterday. I think -- I do agree with, oh, Scott Jepsen's comment that to incentivize production around here for gas, you know, there is a lot of gas to be found here, but the market is the problem. The market is saturated with gas right now, and you're not going to find anybody that's going to go out there and try to prove up a bunch of gas that doesn't have a place to sell it around here.

I mean, unless you can -- I mean, it sorts of pertains to the Copper River as well, but in this basin you've got -- I don't have any of those slides to show you for the 18th time that show the precipitous fall off of the supply curve. But I think Jepsen's comments were kind of right on the money that the supply is taken care of until it isn't, and that's eight or 10 or 14 or 18 years out there. And I don't think anybody's going to go drill a bunch of gas wells and shut them in with the idea of the LNG plant likely closing. That's a political issue I don't care to, you know, go into, and I don't know much about it.

But I think he's right, in the absence of that providing the backstop of a market, and the Agrium guys providing sort of that backstop where if you have to, you could sell it at a cheap price to Agrium. With them pulling out of the purchasing, and the LNG plant going away, all of a sudden you're going to have a bubble of gas that may last the curve suggested last year. I would suggest it's going to last longer than that.

And I think that Enstar's taken care of. Everybody seems to be taken care of for eight or 10 or 12 years. It's going to be a big problem after that, I agree with that, but that doesn't solve the near term problems. You've got a dilemma here of how do you incentivize production for gas -- or exploration for gas without being able to monetize it? No one's going to shut it in for 12 or 15 years. It's not going to happen. I mean, the politicians can talk all they want about how we've got to get guys to come do that, but they ain't going to do it unless there's money to be made.

I don't mean to cast cold water on any of this, but I was asked to be candid, and I think that's some candor that needs to be, you know, put out there.

Anyway, the positives of that ARCO project, the formerly ARCO project, is how can we succeed where ARCO failed. Well, some things have changed since the '90s. The price for one has changed dramatically. ARCO proved a bunch of reserves

out there, and then the price went to $10. It was uneconomic. What are they supposed to do? Not write it off? Not walk away for it and produce it at a loss? Of course they walked away. There are large recoverable reserves in there. The price is much more attractive. We've got improved drilling and completion practices.

As somebody pointed out, maybe Denise pointed out, there's been, you know, a lot of technology available that's not been applied to the Cook Inlet. The idea of subsea completions, the idea of horizontal drilling, new frac'ing technologies, better mud systems, you know, balanced drilling. There's a whole lot of things that have not been, you know, appropriately utilized in this basin, because the basin's been asleep for quite a long time. And, you know, there's going to be a renaissance in this basin. That's a plug for you, Mar. there rally is an opportunity for creative solutions here.

The negatives of that project are it requires a jack-up rig. It can't be reached from shore. You have to drill it out in the water. You've got to get a rig out here to do it. Very high operating costs. By Texas standards, it's astronomical. By your standards, it's kind of state of -- you know, business as usual. There's a large proof of concept cost here.

We have a project up on the Slope that I think we're going to be able to prove or disprove with a modest amount of money, but out here we're talking about spending 50 or 60

million to find out if we're right, and that's a pretty big gamble for a small company. It's a big gamble for a large company. That's why a large -- you know, no one's doing that, and I think we -- you know, stay tuned on that. We'll see what happens.

It's going to require a huge capital investments to fully develop it. If we can prove it, the money will come. You know, it's kind of like the field of dreams deal. If you prove it, you can borrow the money. That's not really an issue.

Down on the Kenai Peninsula on-shore we've got the Eagle and the West Eagle plays. Eagle was what we acquired at the May 2005 area wide sale, and like Benchmark this year, we were the large bidder that year, and we bought about 47,000 acres. Excuse me, we bought about 20,000 at the Eagle that year, and then this next year, this year in May we bought what we call the West Eagle, which is another 27,000 acres. And we're playing the truncation of the cretaceous and Jurassic along the east side for a possible oil play.

I forget who was talking about that yesterday, but they kept saying there's a got reason here to explore along the east side to find the same sort of scenario you find on the west side, that same geologic phenomenon. And we're playing the structural ridges for gas.

Now the lease sold is in that orangey-pink color.

Those are mostly nine section blocks that you see in the grid. We've got our 47,000 acres right there.

You notice that one, that big block off to the east there is a cut out, kind of in the Moose Range. The Moose Range, like that's about as far east as you can get into the Moose Range, and so that's a good place to look for this truncation play. Someone yesterday was saying that ought to be explored over in there, and that's exactly what we've been doing. I went out last night and bought those leases.

Oil can get trucked -- the logistics and the markets of this is if we find oil down in the Kenai, the oil initially could get trucked and then a pipeline could be built over towards Cosmopolitan. Presumably Pioneer will be laying a pipeline into there, and we'll be tying into their pipeline. If we happen to find gas down there, it could be shipped north up to Happy Valley, or smaller quantities might serve the Homer market. I know Enstar's been trying to figure out how to get some gas to go serve the residences down in Homer. So that -- I don't know if that's ever going to happen there, but that's certainly, you know, the market if we find small quantities of gas.

And that's basically my presentation. Thank you.

COMMISSIONER SEAMOUNT: Thank you, Bill. It just dawned on me that I might have misspoke earlier. Did Kathy go to A&M or Austin?

UNIDENTIFIED VOICE: Austin.

COMMISSIONER SEAMOUNT: She went to Austin. So I didn't get it wrong. She's not going to be mad at me. Okay. Good.

Okay. Mark, are you able to come back after lunch if we take an hour off?

MR. LANDT: I'll only take about five minutes. I just want to introduce the.....

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MARK LANDT

COMMISSIONER SEAMOUNT: Okay. Well, we'll get Mark Landt up here. Okay. At this -- in 2004 Mr. Landt joined with James Watt and Allen Huckabay to form Renaissance Resources (Alaska), LLC and serves as its executive vice president and co-founder. Mr. Landt earned a BBA degree in Petroleum Land Management from the University of Oklahoma.

So we've got three archenemies up here. That's going to be a good cause for some very constructive competition I hope.

After graduation, he joined Atlantic Richfield Company where he devoted 25 years of his professional life and served in various land acquisitions, sales and marketing capacities in south Louisiana, South and East Texas, Rocky Mountains, offshore Gulf of Mexico, and California. Mr. Landt also spent five years in ARCO's Anchorage office where he had land management responsibilities in the Cook Inlet and North Slope, and participated on the core team responsibility for the discovery of the Alpine field.

After the acquisition of ARCO by BP, Mr. Landt became a founding member of Prodigy Alaska, LLC that acquired 34,000 acres on the Northern Lights project in the Cook Inlet.

He is a member of the American Association of Professional Landmen.

Let's please welcome Mr. Landt.

MR. LANDT: I wanted to get up and just briefly introduce Renaissance. I think Kay Cashman with Petroleum News has referred to us as the stealth explorers. We've been up here actually about three years now, but most of it's been in conjunction with Rutter and Wilbanks and with Bill's efforts. So let me introduce Renaissance Resource Alaska.

We are a limited liability company formed in Alaska just about three years ago by myself and two co-founders, Jim Watt and Allen Huckabay. And I'll go into their backgrounds in a little bit. Collectively Renaissance has extensive direct work experience in Alaska of over 50 years, and we have others primarily down in Houston that will be joining us once our funding comes into place, that I think we get up over 100 years of direct experience in Alaska.

Again, I was employed by ARCO for most of my career, including Anchorage in the '90s, and my co-founders were both long-time employees of Union Texas and were responsible for Alaska prior to the acquisition of ARCO. Since the early '80s Union Texas explored with partners on the North Slope and in the Beaufort Sea and operated on the Kenai Peninsula.

Renaissance has a proven experience in finding oil and gas and creating value, and I'd say all of us were part of the core team that discovered Alpine, you know, in addition to the exploration with ARCO as well as the explorations involved with Anadarko at the time.

And Renaissance started working with Rutter and Wilbanks two and a half, three years ago. In fact I met him right after he took the deal from Forest over in the Copper River Basin, out in Midland, Texas. We developed I think a very good relationship, and I started to work at that time with Allen and Jim Watt as well as a geophysicist that was also up here with Union Texas, and we started basically showing them ideas that we had in the Cook Inlet, as obviously at the time he was focused more on the Copper River Basin. And so outside of the Copper River Basin, Renaissance and Rutter and Wilbanks now have either submitted high bids or have acquired over 145,000 acres in Alaska, with 67,000 of that located in the offshore portion of the Cook Inlet.

Also during this period of time we have been actively meeting and showing our ideas and opportunities to various investment groups, private equity groups all over the country, overseas. We are, I guess in closing statement, we think we are very close right now to working with a private equity group out of Canada that will provide us the necessary funding to participate in a jack-up drilling program in the offshore portion of the Cook Inlet, as well as an appraisal program that was referred up in the NPR-A.

So on that, thank you.

COMMISSIONER SEAMOUNT: Okay. I said that we would take lunch as soon we could after noon, and I don't know,

for a geologist, geologic time, we're going to be pretty close. We'll finish up the new players now before we take an hour for lunch.

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CORRI FEIGE

COMMISSIONER SEAMOUNT: And I'd like to introduce Corri Feige speaking on behalf of Scott Zimmerman, President and CEO of Storm Cat Energy Corporation. Corri is a geophysicist with 18 years of exploration and development experience in both the mineral and petroleum industries. A Wyoming native whose work has taken her from the Canadian Arctic to Australia, and from the Alaskan Bush to Argentina, Corri is currently president of the Castle Mountain Group, an independent consulting firm specializing in the regulatory permitting and geophysical project management. On behalf of Storm Cat Energy, Corri serves as a point of contact and project coordinator here in Alaska.

So let's welcome Corri.

MS FEIGE: I promise to be brief. I know we're very close to lunch, and I only need just a few minutes of your time. But I do want to thank you all for being here today and listening to what we have to say and learning a little bit about Storm Cat Energy.

I would like to, first of all, extend Scott Zimmerman's regrets at not being able to be here himself today. He would have loved to have been here to tell you about Storm Cat and why we are excited about South Central Alaska's energy future.

Before I go on, I would like to recognize in the audience Keith Napstead, Storm Cat's VP of operations for North

America.

So who is Storm Cat Energy Corporation? We are rapidly growing independent focused on applying strong technical expertise and innovation in under-developed areas where substantial natural gas resources, both unconventional and conventional, can be developed quickly and efficiently. Under the leadership of Scott Zimmerman, Storm Cat has amassed a management team with over 170 years of industry experience combined. We have home offices in Denver, Colorado and Calgary, Alberta.

So what drew Storm Cat to the Cook Inlet region? Well, when Storm Cat looked to Alaska, we were attracted to the northern Cook Inlet, in particular, for two principal reasons. First of all, the basin is largely under-explored. Storm Cat has been able to assemble an acreage position that is on trend with recent discoveries, and is in an area that historically has been only spotty exploration for oil and virtually no targeted exploration for natural gas.

Secondly, the resource potential in the northern Cook Inlet subbasin is high. Looking at the South Central Alaska Natural Gas Study published in June of 2004, that study suggests a potential reserve of between one and three and a half Tcf of conventional gas in both structural and stratigraphic plays, as well as a potential undiscovered producible reserve of up to seven Tcf of unconventional gas in

both coal and tight sand formations. So with numbers like that, the region is most definitely attractive.

But as we know in this business, timing can be everything. And we now have market conditions developing that are no longer a disincentive to exploration. We have a local gas market that is not over-supplied, and we have an immediate need for residential, commercial and industrial supply if we want to offset the extreme costs of converting the region from natural gas to propane and fuel oil, and if we want to keep our industrial consumers, like Agrium, operational.

So bundling all of these factors together, Storm Cat established a position in Alaska in November of 2004 when we took just under 12,000 acres of conventional oil and gas leases on Alaska Mental Health Trust land. In May of 2005 Storm Cat acquired just over an additional 12,000 acres of State of Alaska leases in the Cook Inlet area wide lease sale. And all of that acreage is located on shore in the northern Cook Inlet.

Exploration work that's been accomplished to date has included the purchase and reprocessing of selective seismic data for portions of the northern Cook Inlet. We've completed a regional well correlation and related geologic assessment. And from that work we targeted and drilled our first well in Alaska, the Northern Dancer Number 1 in February of 2006. The Northern Dancer is a conventional gas well that TD'd at 6233. It's located southwest of the community of Houston in section 1

of township 17 north, range 4 west. And at this time we have no definitive plans or timing for completing and testing that well as we are still pending equipment availability.

So clearly Storm Cat wants to be here and we want Alaska in our portfolio, but, and speaking frankly, Dan, we have some pretty significant challenges ahead of us to realizing the resource potential in this region. First of all, we have poor equipment availability, and at time exploitive pricing schemes in the contract community. We must be able to build small explorers and independents like Storm Cat must be able to build win/win agreements with the contract community in this region.

Storm Cat as an alternative to the poor equipment availability is looking into bringing equipment into Alaska from the Lower 48 in order to have better control over our costs and project time lines.

Secondly, we face some challenges with some lengthy administrative time lines. And what this has underscored and brought into clear focus is that Alaska has got to have a DNR and a Division of Oil and Gas that has the staff and the resources necessary to keep pace with the routine business of oil and gas exploration and development.

The third challenge that we're going to face in recognizing the resource potential of the region is that we have an uncertain regulatory picture for unconventional coal

gas development. At present we have duplicative, overlapping and at times conflicting regulatory programs that will lead to open-ended project time lines and will not only negatively impact the project's economics, but its overall risk profile.

And, lastly, we have a challenge to the public perception of oil and gas development outside of the well-known, well-established regions within Alaska, like the North Slope and the historic Kenai. And the only way that we are going to counter that lagging perception is to consistently and repeatedly correct the misinformation in the record with facts. And we can start that process by continually emphasizing two facts, two very important facts.

Number one, that Alaska's environmental policies and protections are some of the toughest in the world. And what that very simply means is that our air and our water and our wildlife and our fish are protected.

The second important fact that we need to stress repeatedly is that the oil and gas industry especially in Alaska is a significant and active partner in building strong communities. When you have a successful resource development program, you benefit all economic sectors as well as the arts, education and local charities.

So if we in this room, Storm Cat and others rise up and meet these challenges, and we are successful in our endeavors, what might those successes bring to our communities, and what

might be the impacts? Well, first of all, we'll see lower energy costs for consumers. That means lower cost of living, lower cost of doing business, and industrial plants that can operate at full capacity.

We'll see new jobs and new tax revenues flowing into the state and municipal coffers, and they'll be coming from new sources. And certainly at the local level, that can open the door for property tax relief. We will have new royalty revenues entering the Permanent Fund dividend, and as we all watched the news last night, we know that that will benefit all Alaskans.

We'll have a sufficient natural gas supply to encourage and grow new industry in the region. And, lastly, we will have a secure and independent energy future for South Central Alaska. And those are the reasons that Storm Cat is committed to doing our part to build a bright energy future for South Central Alaska. Thanks.

COMMISSIONER SEAMOUNT: Thank you very much, Corri. That concludes this section of the new players, and we wish all the new players all the luck you can have. Good luck that is.

This afternoon, in one hour, that would be 1:20. At 1:20 we will reconvene and Harold Heinze will give a presentation on -- we'll start off with Harold Heinze's presentation on the spur line. Harold has told me that in,

what, the good intentions of Citgo who are just are buying a lot of heating oil for Alaska, that Harold's going to provide some free gas for everybody that shows up this afternoon.

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(On record)

HAROLD HEINZE

COMMISSIONER SEAMOUNT: Okay. We're going to get started. We just had a little bit of technical difficulty there, other than the free gas.

Harold Heinze is the CEO of the State of Alaska's Natural Gas Development Authority, ANGDA. Considered an engineer's engineer, Mr. Heinze left retirement in 2003 to lead ANGDA in the planning, engineering and development of Alaska's in-state gas pipeline. With 37 years in oil and gas, the past president of ARCO Alaska enjoys living in the north and values the Alaska experience.

Graduating with honors from Colorado School of Mines with a petroleum engineering degree and serving as an officer in the U.S. Army was just the beginning for Heinze. He arrived on the shores of Prudhoe Bay six months after the 1968 announcement of its discovery and began working as a field reservoir engineer. Mr. Heinze went on to numerous ARCO management positions in the engineering, planning and transportation of petroleum.

He retired from ARCO in 1990, but retirement wasn't long lasting since Alaska Governor Walter Hickel appointed Harold Heinze as Commissioner of Natural Resources that same year. As Commissioner Heinze, he finalized the land selection of 100 million acres granted to Alaska at Statehood.

Mr. Heinze is well respected for his community

involvement, creativity, open management style and sense of humor. He is married to Cheryl Heinze a successful artist, retail shop owner and former Alaska Legislator.

Let's welcome Mr. Heinze.

MR. HEINZE: Thank you, Dan. Well, I guess really just as we bring this up here, I need, number one, to make sure that probably most of this audience realizes that ANGDA is a public corporation of the State, so we're a business and we're also a political subdivision of the State. What we try to do it use the best parts of both of those things.

We also in the handouts out there have just a really slick little diagram there, it's called a VIN diagram. And the reason we put that in there was that our big effort right now is working on a business plan, and as that business plan comes together, what we're trying to sort out is what our roles are in working with the North Slope gas to market issues and getting the benefits to Alaskans. And this is just a way of trying to express those different roles and, frankly, we have not decided yet, but expect to decide within a matter of weeks what we want to be when we grow up. So stand by.

The other side of that, of course, then is a genuine souvenir map showing the different routes, and so when I refer to the map there, you've got a better version than you're going to be able to see on the projector.

One of the advantages of coming later in the program is

that you've heard everybody before, and it really puts you in a great position to decide sort of who you want to agree with, you know, and sort of who you want to disagree with as you go forward. And in my case also it allows me to strike a pretty good balance of how much do I want to present versus how much do I want to preach. And so I'm going to attempt to balance all those things in going through this.

And to explain to you a little bit maybe the context of the presentation today, earlier this week I was at another conference, and somebody used what I thought was a really good quote, and so I decided that it maybe captured a little bit of where ANGDA is and where the whole spur line issue is and everything else. And the quote was this: Spectacular achievement is always preceded by unspectacular preparation. Okay. Spectacular achievement is always preceded by unspectacular preparation. You know who said it? A famous NFL quarterback, played at the U.S. Naval Academy in his college career. Okay. Roger Staubach. Sure.

And that's where I kind of feel ANGDA is at times. I think we've finished about two years of unspectacular preparation, and we've probably got about two more years of unspectacular preparation, and then it's just all going to be glorious. And so it's with that sense that I approach the talk today.

We have spent the last two years defining how to make a

spur line project work. And there's a lot of elements that go into that. I'm going to cover a few of them that are worthy of consideration, but I want you to understand there's still work out in front to be done to make all this work. But that's our approach to it. We're not trying to make a decision as to what is done to solve Cook Inlet energy issues. As a matter of fact, I'll remind you that Carolyn Dunmire who you heard speak this morning, that study was commissioned by ANGDA, and the reason we commissioned it was we honestly wanted to know what was the range of alternatives, what were the pluses and minuses, and what was it going to take to come up with several good ideas.

And not to steal my bottom line at the end of the talk, I will tell you that I take a view that says there's a lot of things we need to be doing simultaneously. It's not a matter of picking exactly what to do. There are many different options. We need to pursue them, we need to mature them, and that time will come.

So let me just sort of jump into it maybe. The first thing again I just want to cover is ANGDA is a public corporation of the State. I don't have to meet quarterly profit goals, those kind of things. I am accountable to my seven member board for whether we are achieving those kind of benefits that are illustrated here. And you'll notice those benefits stretch all the way from the North Slope, the Yukon

River, Fairbanks, and as well as coming into this area. And that's all within our charter.

Basically we were asked to -- by the initiative process that created us, we were asked to help bring North Slope gas to market and do it in such a way that Alaskans benefited.

One of the things we hit on early in the process was that there was a looming energy crisis, the combination of the cliff we talked about earlier in terms of Cook Inlet production and the demands that are here, and how they intersect. And this is a chart not much different than the ones you've see, other than to remind you that the only reason that line doesn't cross until out there in 2013, 2014 is that we shut down the only two manufacturing facilities we have in Alaska. And if you take that sort of top line way over to the left of demand and project it across, you can see that the gap actually occurs tomorrow.

And so to me that's the crisis of the decision here. It's not that we're going to run out of gas tomorrow, but we're going to have to make some very hard decisions tomorrow. And that's what we need to be thinking about. That's why I think it's great that you all are having this conference and sort of put it on the front burner right now. Even if we don't know all the answers, at least we can work towards that.

The other thing I guess I should make clear is that this -- the pie chart to the left shows where the gas is used

today. There's a different version of it in the handout we gave you. It's more by company name, but it's the same basic idea of where utilities are, and who they are, and what they're doing.

But the important thing is that about one-third, 70 Bcf a year is used basically to heat our homes and light our homes. They are driven by people. The other two-thirds is an industrial use of the gas. It's an important industrial use, but its different definitely than the structures you and I face in it.

The other part you need to understand is that a certain part of that, the 35 that represents the home heating, that represents Enstar, their system can only use gas molecules in it. They can't ship electrons down those pipes, so when we talk about energy needs and alternatives, you have to keep in mind that if you have gas heat like I do, to not have gas available has very serious implications. Now, when I use an electron and I flip the switch on the lights, I don't care if that came from hydro or gas or coal or whatever. It's all the same. But it does make a difference in some of the very basic uses of gas. And that also affects our industrial people.

The one on the right there is, again just to sort of set the stage, if you take a positive view towards the world, and again I'm one of those people that, you know, the glass is half full, so when you take that kind of a view, the chart on

the right represents what could be. If we had a plentiful gas supply into Cook Inlet at a reasonable, not cheap, but at a reasonable price, that's the kind of situation we could be faced with there, not only in industrial use that continues, but actually expands.

And the reason that's important is, as we'll show you later on, the industrial customers and their presence helps pay the bill. And I care what my bill is for gas when I heat my home, and having those people around is good in terms of helping in that bill.

Now, the spur line idea is pretty straight forward. Basically if you have a main pipeline, 48 inches, 50 inches, 52 inches, and it's running from the North Slope and basically follows the highway on down through Canada and all that, it's going to be a system that is operating at about 2500 pounds per square inch, psi. And the reason is that that's probably the most economic pressure to operate on, and also it allows you to take all what's called the natural gas liquids with it. So in an operational sense, that's a very favorable circumstances. Twenty years ago when we were looking at this same kind of pipeline, we talked about a much lower pressure. But the advances in metallurgy make this possible, and we're probably looking at that kind of a system.

The other difference is gas pipelines like this operate close to the freezing temperature. They're chilled. And they

operate as underground pipelines buried the entire way. And that's different from the oil line which is at 140 degrees.

Now, I made a couple other points there. One of the differences between the spur line and the main line is that the spur line serves individual customers There's 150,000 households in this area that can be pledged against the financing of that spur line. It is a utility. And as such, it has available to it some very low interest financing, which in turn keeps the tariff low, which in turn keeps your bill low. So there's some real direct benefits there. That's different than a long distance transmission line which is basically on the guarantee of the individual shippers and their financial strength.

There's a lot we don't know about how the spur line would run and all the conditions at the end of it and the beginning of it, and a lot of other things. All that's dependent on how things move forward and when they move forward and a lot of other decisions that are not ANGDA's to make, and we just try and stay compatible with all the concepts that are out there, all the projects that are out there.

And then, finally, I always like to raise the issue of the interesting part of the spur line is that it could be the first part of the pipeline built. And the reason for saying that is that it is quicker, smaller, cheaper, and logistically it has some real acceleration possible on it, because it's easy

to get pipe and so long. It also might provide a wonderful opportunity to train 500 Alaskans in actually pipeline construction so that when the big pipe comes along, they're ready to go and they've had two years of on-the-job training that well-qualifies them.

When we talk about the spur line, there's two basic ways to kind of look at it. One way is to come off a main line in the Fairbanks area, basically follow some combination of the intertie, the Parks Highway and the Alaska Railroad, slip by, through, around, over, under, something, Mt. McKinley. Between the topography and the land ownership, that's always going to be a pinch point, and you've got to slip through that pinch point somehow. And then south of there you basically can just run on either the Alaska Railroad or the highway or some combination again of those right-of-ways on south into the Palmer area.

The other way is to basically stay on the big pipe to Delta, and if you remember, of course, at Delta is where the highway project would continue on down through Canada, heading down through Tok and all that. But at Delta is where the Trans-Alaska Pipeline heads south towards Glennallen and then on to Valdez. So if you come off at Delta Junction, you go south to Glennallen. From Glennallen you turn right and head west again to Palmer, basically following the Glenn Highway route.

And the route we've actually looked at and spent some time on and actually have obtained a conditional right-of-way from the State is a route that is largely based on the Glenn Highway, but it has about a 50 mile bump up through that stretch in the middle of the Glenn Highway that, if any of you remember driving it, it is the more thrilling part to drive, and it also is the more thrilling part to pipeline through. So we looked at an alternative way around that area.

Right now there's a number of studies going on. One is there is a Department of Energy Study looking at these two routes. And regardless of what was said yesterday, I assure you the Department of Energy has not made any choice or recommendation on the two routes. They're both on the table. From our point of view, we need to understand both of them. There are virtues and sins involved in both of them. And ultimately the commercial situation will make the decision as to what would happen.

You heard a reference earlier today from some explorers out in the Glennallen area who, if they found something, that might influence which route was chosen. In a similar way, if something is found in the Nenana Basin, which is just north of the Healy area, north of the Park area, that might influence that choice in the routes. And so on. There's a lot of other factors that come into it.

But the realty is that both routes are about 300 miles.

They're about a billion dollars. Okay? And that's all you really need to kind of know right now to work the problem, other than we're going to keep advancing both routes to understand them better.

And I guess I should explain understand them better. The way to think about pipelining is, is 95 percent of it's really easy. You dig a ditch, you put together some pipe, you put it in the ditch and you cover it back up. And it's about that easy for 95 percent of the route. Now, there's five percent of the route that's really difficult, and that's the part you have to understand, because that controls the time line, it controls the money, it controls a lot of things. The feasibility. So when I say we need to understand more, we need to understand more about the difficult parts, not the easy parts.

One of the questions we always get about the spur line is, well, you know, if Agrium shuts down and the Kenai LNG plant shuts down, why are we bothering to look at this. And you heard a little bit of that flavor yesterday from one of our lead-off economist. If you read the Anchorage Daily News, you'll find there's one editorial writer there that probably shares that view of it will never work.

Well, I'm here to tell you there is a rational case that says under a very wide range of circumstances, the spur line makes sense. And if you'll take a few minutes, in the

handout especially I've enlarged this chart so that you can see it, and it's very similar to one that Chuck Logston presented this morning. It's not in any difference with it. It's just a little different way to look at it.

Now, all the data in this chart is taken from a Department of Energy study that you're going to hear more about from Charles after I finish, but I am a faithful remover of their numbers. It is not their table, it is my table made from their numbers. So, you know, it's one of those where I did the arithmetic part of this.

And the way you use this chart is up at the top is the assumption that the price in Chicago is $5.50. And in this case, they had a tariff number of about $2.40 to get here. So if you do the net back calculation, you subtract it off. That puts you at $3.10 in Prudhoe Bay. Now, if you come forward with that $3.10 to say Fairbanks, it's not very expensive, as you can see, to get to Fairbanks. And that's because on a distance-based, mileage-based tariff, instead of going 2,500 miles at $2.40, you're only going a few hundred miles. So that's almost a guarantee that those numbers are right if the $2.40 is right.

You'll also notice that if you do the arithmetic, look at the price in Fairbanks. $3.10 plus, you know, a few bits is still probably $2 under the Chicago price. Now, that's a pretty good deal. And if you get off at the Yukon River, it

might even be less than that. Okay.

Now, the other thing that happens then if you're going to bring gas into this area, make believe we've got the gas at Fairbanks. It's about $2 under the Chicago price at that point. And then you look at how much does it cost to come into this area. And the answer is a billion dollar pipeline, it matters how much gas is moving through it. If there's only a little bit moving through, the fare, the tariff is pretty high. If there's a fairly large amount of gas, it becomes pretty modest in price.

And that's what this table shows. On the left-hand side is the column that represents 100 million cubic feet a day. Now, that doesn't mean anything to you. That number is the same number that is equivalent to Enstar heating all our homes. So just imagine no use of gas for power generation, no industrial customers, no new uses, no nothing that helps this work. And basically the Enstar volume has to pay the full fare. And you can see there the number is slightly higher than Chicago, but not a lot higher than Chicago. And very frankly, the way I look at it is if I as the home owner am faced with converting from gas to fuel oil, that's a not enough higher number to make me do it. It may not be a number I like, but it's a number I can live with.

And you'll notice every other volume after that, the 200 where you're looking at both Enstar and electric power, on

up to 500 which is what we use in Cook Inlet today, and 800 to a billion which is the kind of case I showed you earlier, where we have a lot of other uses for it, the numbers get pretty reasonable. As a matter of fact, a dollar or a dollar and a quarter advantage on Chicago is a pretty good price structure to be under.

Now, the advantage of all this to us here in Alaska is that we don't have to make a decision on building this pipeline until we know how much is going to go down it. But we have to keep the option open. We're not going to build a grain silo here, because this thing has to be financed, and it's going to be financed on the basis of commitments that are made. And so that's the advantage. The numbers in this case are pretty workable.

Later on from Charles you're going to see a whole part of the Department of Energy study where they looked at the relationship between price and demand, because again we've talked about at high prices you destruct or you make demand go down. And he'll show you a whole section on that.

But this is just a simple illustration that under a fairly wide range of circumstances, you probably end up with a very livable gas price situation in this local area.

One of the other things we've looked at is the fact that North Slope gas is very different than Cook Inlet gas. Cook Inlet gas is almost entirely methane as you heard the

geologists talk about it this morning. And in the terminology, that's lean gas. Okay.

The North Slope gas is what we call rich gas. Besides the methane, it has lots of ethane, propane and butane. And those are great little molecules, because under different pressure and temperatures and things, they can be liquid. They also are the basis of petrochemicals. They're good for a lot of different things that you can't do with methane.

What you need to realize is the entirety of the industry that has developed in this part of the world is based on methane. And when you start to talk about having these other molecules available, you've got to start thinking from scratch about what can I do with them, because there was no reason for anybody to build anything before that used them, because they weren't here. But now we can have them here. So what are you going to do?

One of the things we looked at was propane, because it's very clear there will be several tens of thousands of barrels of propane that could be available in the area. They could be available in Tok, lots of different places. But if we had a couple of tens of thousands of barrels of propane here at tidewater, we could start to think about our marine movement of those propanes.

And propane's a great fuel because it sits in a tank that isn't under very high pressure, it works in all our

temperatures around here, and you've probably got a bottle of it on your back porch and it hasn't scared you yet probably. And I know my cabin up in Talkeetna, we do lots of things with it. You can run lots of appliances off of propane.

So we looked at that and we said this may be something that can kind of help. And there's a study out there on our web site that you'll see that will look into this. And what we found was that if you worked on the logistical system to deliver the propane all up and down Alaska, north and south to everywhere, there are hundreds of communities involved, you might be able to help in just about every one of them.

Now the trick is that again you got to start thinking about new ways to do this. We are not going to go hauling around 100 pound bottles, okay. I don't like them, they're too heavy. We know they are dangerous and a lot of other things. But one of the things that exists out there is in the iso-container sized propane tank. And these exist. They're used in some parts of the world.

We don't use them up here, but there's no reason we couldn't. There's no reason we couldn't make them here, as a matter of fact. Build our own. And the great part is these containers can be shipped on a barge along with any of the other cargo to the community, you drop it off, you pick up the empties from last year, okay, and I'll bring it back next year full. Okay? And it's a very simple sort of business

transaction, whatever that you have going here. And then within the community they distribute it, they do whatever they're going to do. And those local entrepreneurs, they make it work.

That's one example of things we've tried to think about that would allow, number one, more volumes to be moved through a spur line. It would open up whole new ideas as to how to let other Alaskans share in the benefit of the North Slope gas and at the same time create all kinds of entrepreneurial and creative uses of these things.

Now I'm not going to take a lot of time to talk about it, but we also looked at this and right now on the North Slope to give you a feel, there's about 100 to 150,000 barrels a day of ethane propane and butane that every day are reinjected back into the ground. And if you can imagine those moving down the big pipe there may be enough ethane there to form the basis of a petrochemical industry.

Now, the when, why and how of that I don't know, but the good news is we don't have to make that decision today, we don't have to make the decision tomorrow, but I strongly argue we need to keep that option open for the future so we have the ability when we know more to make that decision.

Now, the other fly in the ointment I want to talk about here very quickly is -- and Chuck talked about this before lunch or a little bit earlier this morning, was the concept of

open season. If you remember what I talked about here is the main line, a big pipeline where you sort of hitched a ride on it first and then you got off on the small line. Well, when you're on the big line you're in the federal jurisdiction. And what I've described on this slide is the classic sort of federal view of what an open season is about.

It's a way of allocating capacity. Many of you are familiar with the Trans-Alaska Pipeline. On the Trans-Alaska Pipeline every month you say this is how much I got to ship. And if there's more people wanting to ship than there is capacity, you just get prorated. Gas lines don't work that way. Up front you have to say this is how much I want to ship for the next umpteen years and oh, by the way, I will pay you for that shipment even if I don't ship the gas. So it's a ship or pay contract. It's a firm commitment. And that's what builds the line is those commitments. Okay? Now that's also how you allocate or get space in whatever is built in terms of the pipeline. You influence the design, you influence the financing.

The key point is that the credit worthiness of the people who are making those commitments is what determines whether the line gets built and how they're treated in that line, and everything else. And that part of the system has to play out in terms of the federal rules. In other words, in the big pipe, to ride in it you got to play by the federal rules.

And then we get off -- let's say you get off at Fairbanks and you're coming in this pipeline into this area, you have to do another capacity allocation type approach that's under the jurisdiction of the Regulatory Commission of Alaska. Okay. So you got to find a way to mesh these two different regulatory processes.

Oh, and by the way, most of the shippers are going to be utilities, and guess what, they're regulated by the RCA. And guess what, the pipeline is regulated by the RCA. And they also have to be involved in the open season process. And oh, by the way, you have six months to do this from start to finish. Okay? With boards of directors that have to go through or consider these kinds of things, the negotiation possibility is there, the bidding thing is there, but these utilities may be faced with commitments that are huge.

We went through and calculated what it would take for a local electric utilities and Enstar to make a commitment, a reasonable level of commitment to get gas delivered into this area. And they would have to sign firm documents totaling about five or $6 billion. Now, fortunately, they don't have to write a check the next day for it, but they got to have a credit worthiness that will support five or $6 billion. We looked at what their asset base was, all the other financial measures we could find, five or $6 billion is two, three, four times what these companies are worth. So the decision they'll

be making is a venture company decision, it also will be a bet my customer decision, and so it's crucial that they get this one right.

Now the dilemma is this. If you can't successfully work through all these things in that decision process, if you can't participate in the federal process, if you can't make it work with the RCA, if you can't get all those things done in a timely fashion with some level of confidence, then you can't play. You heard it described to you very carefully this morning that the State has provided offtake points. And that's right. What they've provided is the possibility of taking gas off. The actual doing of that is a commercial transaction that involves all these elements. And, again, back to that unspectacular preparation stuff, we need to work on this because when the time comes it's going to be very difficult.

I spoke to the Alaska Power Association a couple weeks ago and what I said to them is the good news is you don't have to make this decision today. The bad news is you're going to have to make this decision and it's probably going to be the biggest decision in the history of your utility. So we need to start working forward towards it and now.

Okay. Just to sort of end up here, ANGDA has spent it's time worrying about to make the spur line work. And, you know, I wish it was just as easy, and maybe I started out too easy. I thought it was just going to be, you know, you kind of

figure out which way to run the pipe and how much pipe you needed, and a few things like that. How many dollars and, you know, how much will the bankers give me and everything else. Well, it's not. It turns out it's a much knottier problem than that. And here's some of the things we think have to happen.

We think that the regulators need to be engaged in the dialogue as early as possible in this. Our utilities are not necessarily used to working with each other in very close consort. The electric utilities, in particular, have a history of being very parochial about each of their respective areas. This is not a problem that's going to get worked that way. You got to be willing to work together. And we got to have a lot more cohesiveness.

There are some things that it's important that the State do. The Regulatory Commission of Alaska went through a hearing process, has recommended that we make some statutory changes. And more importantly, I will tell you, as we talked about this morning, there are definite decisions to be made by the policy makers, in this case I believe the Legislature, as to how we want to deal with the issues associated with making gas available, under what terms, and how we wish to price them and all that. And I believe I've made some very reasonable assumptions. I'm certainly not looking for anything.

One of the key things we see is that it's really important to involve everybody in Alaska in getting some of

these benefits. And, again, in our mind that ties back into the constant theme we've had which is keep looking for ways to be of benefit to a large amount of folks.

So I'm just going to leave it there for now. We do have a panel later on. I will probably speak up a few times during that as circumstances permit or questions permit, or whatever. But the other part is that as an arm of the State we are totally transparent. We have three web sites that are shown there. If you just Google aim, don't get confused, just Google aim and you get over 1000 hits. By the time you're through the first 10 or 20 of them you'll know more about us than I do. So feel free to explore any of these.

Always happy to talk. Always happy to talk to Rotary groups, whatever, any time or place or whatever. And, you know, because we really believe that the important element here is that people be aware of what it's going to take to make all of this work. Because it's too important to leave it to chance to not have it happen because we didn't work at it hard. So thanks.

COMMISSIONER SEAMOUNT: Thank you, Harold.

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CHARLES P. THOMAS, Ph.D.

COMMISSIONER SEAMOUNT: Our next speaker is also going to talk about the spur line analysis. You can see the third talk was entitled Importance of the Spur Line to the Kenai Peninsula Borough. And our next speaker, Charles Thomas, well, he's head of the SAIC study teams, is that correct? Okay. He said probably the best person to speak to that would be Bill Popp. And is Bill in the audience right now? Did you say enough about it yesterday or would you like to make a few comments after Charles is done?

MR. POPP: I'll wait until the forum.

COMMISSIONER SEAMOUNT: Okay. Good. Okay. So our next speaker is Charles Thomas. You all heard him talk yesterday. You got his bio from me yesterday, so we'll just welcome Charles again.

DR. THOMAS: Thank you. Let's see if I can stand the right distance from this thing. And a good friend of mine suggested to me yesterday that I might have gone a little too fast through my slides. I tend to do that. So if I'm going too fast you can wave at me, I'll try to slow down.

We'll talk about the spur analysis that we did at SAIC, several members of the team. Almost too many to list. That report that you see depicted there is available on line at the U.S. Department of Energy's National Energy Technology Laboratory web site. Bill Popp also has it on his web site.

And he has actually broken it into the executive summary as a separate one so it won't take quite so long to download, which that's probably what most people want to see anyway.

So overall study objectives. Want to develop an estimate of the potential spur pipeline demand in South Central Alaska. We also wanted to estimate how much gas -- part of our charge was to estimate how much gas would be needed in Central Alaska, basically the Fairbanks area. And that could be extrapolated to others.

We also were to provide some of the basic input from the other follow on studies that Harold has already mentioned related to route and so forth. As Harold said, we found the same thing. We started off with what sounded like a pretty simple statement of work. The more we got into it the more we realized there were a lot of things we had not thought about and we worked on them pretty hard, and you'll see some of these results.

Methodology. We assume that, of course, this has to be an Alaska gas pipeline from the North Slope down through Alaska, Canada and on into Chicago in some form or fashion. Four and a half to 6 Bcf a day, dense phase line operation by about 2015. The spur pipeline scenarios that we looked at would be a dry gas line where you just bring in basically the methane, utility grade gas, to serve in its limited service to residential, commercial, power generation, the LNG, the

fertilizer ammonia urea, and natural gas to liquids. We also looked at some other smaller activities that you can read about in the report that don't -- you know, really aren't large enough to anchor a spur pipeline.

A dense phase line containing the natural gas liquids would do all of the above plus generate the possibility of a petrochemicals industry and say propane that Harold has discussed previously.

We used financial modeling to estimate the economically viable demand. We looked at this strictly from an economic point of view. Market drilling, did not try to get into analysis of what options the State might have from a public policy point of view.

So what we wanted to do was determine the minimum price each sector can pay and be viable in South Central Alaska. We did do a little bit of work on Fairbanks but not very extensively. And then we consider the Fairbanks area demand independent of a spur pipeline.

I'm not sure I can read this one from here. But we've got the dense phase gas coming off the North Slope going into separations. We have the natural gas liquids coming down this route. And maybe let you read that for yourself across the bottom for the petrochemicals, so forth there. Then the dry gas coming over this way and the list of uses there.

This is a picture we put together and trying to

understand it ourselves is sort of a cartoon, I would all it. The North Slope, we're talking about. As you know there has to be a conditioning plant to take the CO2 out and condition the gas. Then you have the raw gas coming down. You could have take-off points there at the Yukon River. You take off in Fairbanks some raw gas. You have to have a separation plant. If you're going to bring dry gas to South Central that separation plant then would put the natural gas liquids back into the large line to move further south into Canada and the Lower 48.

Dry gas, the way we looked at it, is you would take that off and have a distribution system in the Fairbanks area. Once you get to South Central now you've got dry gas. You've also got the gas being served from the North Slope gas plus what's already in Cook Inlet now in terms of proved reserves and future exploration and development that we've heard a lot about in the last two days.

The next one, if you do a dry gas line from Delta Junction you're still going to want to have this situation here to serve Fairbanks. And then basically you've got the same thing at Delta Junction that we've discussed before.

This last one is now the dense phase line where you're going to have your methanes plus all the natural gas liquids. The same thing except now you'll come in, get what you need out for Fairbanks to serve its needs, put some maybe dry gas back

in the big line, bring raw gas down all the way. You can see that various assembly things that come in there. But once you get to South Central with enriched raw gas, or the dense phase, you're going to have to have a separation plant there as well taking the natural gas liquids for your petrochemical and industry and propane, dry gas as we've discussed before. So, hopefully, that helps if you haven't really thought about all the pieces of this.

You've got to have not just pipe but you're going to have to have some separations plants to get the gas and various liquids in the form that you want them and where you want them. It doesn't make any difference whether it's in the Yukon or somewhere, you know, the Yukon River or somewhere along one of the spur lines, you still have to get the gas in the form that you need it for its use.

Okay. Now to our study assumptions. We looked at basically large gas intensive industries scaled basically to work to world class size. For the economist types we used 12 percent discount rate, 20 year project life. Going to report things to you in 2005 dollars rather than in dollars of today. Here's the size again of the wellhead price. Harold has already discussed this. It's basically now tied to the Lower 48 prices minus the tariff. So now we're connecting ourselves in Alaska to the North American system.

The Fairbanks price is going to be the North Slope

price plus tariff to Fairbanks. South Central you add on to that spur pipeline tariff. The future gas demand, that is the way we looked at it, is not part of the spur pipeline. It will be handled separately. Final analysis might determine that would be different, but that's what we assumed here.

So, in addition, now your South Central natural gas supply consists of what comes through the pipeline plus existing reserves in the Cook Inlet. The price assumptions that we made, basically the EIA, U.S. Department of Energy's Energy Information Administration's forecasts. And we heard it mentioned yesterday and it's been mentioned several times since, forecasts are always wrong. We just don't know how wrong. That's certainly true of these forecasts and the forecasts that I'm discussing here.

But if we take then the Henry Hub price, we're looking at this EIA forecast in the dotted line right here, the average over this time period of 2015 to 2025, you can see it listed there in 2005 dollars, it averages about 5.41. We also needed a world oil price because the gas to liquids would be generating liquids that basically go into a liquids market. So we had to have that as well. We used the EIA price for that.

We also ran any number of sensitivity cases. The high gas price, low gas price, and we varied them by $2 per million Btu and then some other cases listed here. I actually like Harold's slide much better. The differences might be a few

cents here and there. But if you go through this the EIA Henry Hub price, the forecast gives us, I believe, five to $6 during this time period. About $2.30, that's per million Btu rather than Mcfs, so there's a little conversion there. The wellhead price then would vary during this time frame from 2.70 to 3.70 with these assumptions. Then the tariff to Fairbanks in the range of 55 cents giving the prices that we talked before, 3.25, 4.25, in the Fairbanks area. And depending upon, you know, what kind of spur pipeline you have and how big it is and the various rates, can give you different values in South Central. But basically four to $5 per million Btu.

These are our results. Dry gas. In other words, we looked at residential, commercial and this says -- and by the way, this number over on the far right column in 2005 dollars at a point in time, 2025. Never did figure out a way to depict to that simply through this whole series. So that's the rate that we estimated there. This value says that if gas was this expensive once it got to South Central you'd probably want to switch over. People would start switching to, you know, distillates or something of that nature.

Power, that number is about 5.20 for the quantity listed here. Ammonia urea at 2.79 based on the assumptions that we used for the price of their product, capital costs and all those things. The LNG, I can't even read that from here, 212. Gas to liquids is about 320 as I recall. And we looked

at a fairly large plant, 50,000 barrels a day. So you're looking at using a lot of gas. That's with your dry gas.

Now if you have a dense phase wet gas line you have the potential for petrochemicals, the price here is 4.60. And you see the quantities that we're talking about that Harold has mentioned. They're large. The next line down would be LPGs and you can see those numbers there. So if you total all of those up you would get all the way down to about 1.3 billion cubic feet per day.

Okay. There we go. Okay. This is, again, an attempt to portray this in a fairly simple manner. Sort of a snapshot in time at 2025. This is the range at which we say we could, under these assumptions, deliver gas to South Central. And these are those prices that you just saw depicted by numbers. That says in this price range you're looking at residential, commercial, power, petrochemical and LPG, with all of these others under those assumptions not making the cut. That's depicted a little further here.

In order to meet those needs we're looking here over time yearly averages. And we have a piece in here in our power estimation that includes a Pebble Mine at about 50 Bcf a year, I believe. I'll have to get those numbers exactly. But showing it starting in 2009 and I'll show you in a minute we've actually moved that out, and I guess there's always the possibility that won't happen.

And then the red line being the Cook Inlet forecast that we had at that time, and you've also seen various depictions of that. We know that it appears to be growing and a lot of enthusiasm to grow it even more. So if we show this on a monthly basis and we show the growth that we put into the use, you can see that you might need all the way out here at the end 350 million cubic feet a day, we'll say. 80 million cubic feet a day of storage deliverability is depicted in this slide here. So that's basically the basic base case results.

Okay. This I showed yesterday. This would be Division of Oil & Gas' most recent forecast. And this was with the Pebble Mine power needs moved out to 2014. And, again, with the industrials potentially going out as shown here. Our low price case moves the gas down and other things begin to come back into the picture. Without going into all of those let's just give you a rundown now on study conclusions.

Number one, 350 million cubic feet a day for dry gas pipeline serving residential, commercial and power needs. That's the least speculative of the spur pipeline scenarios. The next would be a 590 million cubic feet per day dense phase line. You're getting rather speculative. You would serve all the dry gas needs plus petrochemical industry and LPG.

The next one down even more speculative, would be a million cubic feet per day dry gas line where you would hope to be able to service LNG at its 212 cubic feet a day rate. A gas

to liquids plant at 480 million cubic feet per day. High uncertainty on this one because of the product price and the capital cost. We used $20,000 per daily barrel. That is in the range of the target that the majors talk about needing to get to for gas to liquids to be commercial.

However, in our review it was pointed out that current plants are still going at 45 to $50,000 per daily barrel. And recently Ann Gutter ran across a forecast that shows plants now going to cost $100,000 per daily barrel. So that puts this in a rather speculative territory at this point in time. Some of that is may be related to the price of steel and all those other things that are coming into the picture that we all have to worry about now.

Then at the very end, if we could stuff everything we might like and do everything we'd like to do in South Central you might get up to 1.3 million cubic feet per day, then you can do it all.

Once you get into number three and four, if you're only going to come off the Slope with 4.5 million cubic feet per day -- or Bcf a day, you're taking a lot out of that line. And I think you're really getting into some issues about the economics of the Alaska Gas Pipeline and the design criteria there. So those are really speculative areas that would require a lot of study.

Okay. I promised a quick look at Central Alaska gas

demand. Right now there's very little. Natural gas use is very limited in Fairbanks. However, with the prices that gas would be arriving in Fairbanks we certainly project there would be a significant growth and change over to using natural gas with the development of a distribution system. This is the forecast. And you can read the numbers there, .44 I believe for power and 24 for heating, if I've got that correct. So that shows the demands there.

So I showed this slide yesterday just about entirely. When we look at South Central supply options you're looking at, you know, again exploration production for conventional gas, unconventional gas is available we know. We can import gas from outside, meaning through a spur pipeline or LNG import. And then the other potential factors that we have talked about, contributing factors any numbers of times yesterday and today, gas storage always, conservation increased efficiency is certainly well worthwhile. Reduced industrial use or make some conversions to other sources such as coal. Power generation alternatives.

Summary and observations. I struggled a bit with how to say this. What we have done, and as Harold I think has said it, you know, we've done the best we can with what we know at this point. There's a lot more work to be done. There's cost benefit analysis to be done on all of these options. How do they fit together? You know, if you bring in spur pipeline gas

and set a price or you start switching to coal and coal now becomes your base energy price on a Btu basis, how does that impact the future of all of these things and how do they work together? What's the best alternatives? What's the best mix?

And I think my economist friends call these a portfolio problem, a real option problem that needs to be worked. It's a probablistic thing that says what's the best mix for us to try to promote? You know, what will the market do? And then maybe that brings into the realm what would policy makers, what kind of decisions should be made to do the best thing for the state, the region and the nation?

So that's what I'm trying to say right here, what's the optimum mix of supply options? And I think we heard in the first presentation this morning different people might define optimum in a different manner. And we all have our opinions on what's the most important thing to us.

So again -- and then, you know, LNG imports. I think it was mentioned ships will be coming by from Sakhalin going to the west coast 200 miles from here. If you start bringing LNG in, what does that do to us? I don't think any of us probably want to see that, but it's always an option before the lights go out or our houses get cold. With that, if I hit the right button, thank you.

COMMISSIONER SEAMOUNT: Thank you again, Charles.

MIKE BARRY

COMMISSIONER SEAMOUNT: Okay. That concludes this panel and we'll go to the next panel which is coal power. Our first speaker is Mike Barry. He's an Anchorage resident. Was appointed to the Alaska Industrial Development & Export Authority's board of directors on January 16th, 2003 and elected chairman.

He has spent 10 years in property management and development in Anchorage, working primarily as the owner's representative of the Dimond Center, Alaska's largest retail multi use commercial complex. He also spent 20 years working for National Bank of Alaska in a variety of positions including commercial loans, trust investment, branch management and credit analysis. Please welcome Mr. Barry.

MR. BARRY: Good afternoon. When I was contacted a few weeks ago about my appearance here today I was asked if I'd be willing to talk about coal. And I said that coal is very timely. I have a program that will put Alaska at the forefront of a national path to create energy self-sufficiency, eliminate the refinery gap, reduce the balance of payments deficit, mitigate global warming, reduce air pollution, increase automotive fuel efficiency and power performance, enhance national security, increase domestic employment, augment the local tax base, and reduce the cost of electricity. I was told great, we can give you 15 minutes.

I want to talk to you about coal to liquids. What is coal to liquids? Coal to liquids is the conversion of cold into ultra clean transport fuels utilizing gasification and Fischer-Tropsch refinery processes that have been in commercial continuous operation for over 50 years. This is a proven technology which has only recently become economic with increased prices of crude oil.

The United States consumes over 20 million barrels a day on an annual basis. This is more than double the amount in 1973 at the time of the first oil shock. Even as our consumption of oil has increased in the last 30 years, the percentage of imported oil has more than doubled. Or nearly doubled. Competition for oil has increased even more dramatically. China alone accounted for over 40 percent of the world's increase in consumption last year. China plans to add 120 million vehicles to its fleet over the next 10 years requiring nearly 12 million barrels a day in fuel.

India will increase its fuel consumption nearly 30 percent in the next five years. It is imperative that our nation develop alternative fuels and coal to liquids will be one of the prominent answers.

On an annual basis the U.S. imports more than 3 million barrels a day of refined product. Congress has begun to provide incentives to alleviate this costly problem. Coal to liquids will be an important part of the solution.

The cost in U.S. dollars to pay for imported energy comprises nearly $350 billion a year. The balance of payments deficit increases every American's cost of doing business, borrowing money and purchasing goods on someone else's currency. CTL keeps the dollars at home and reverses the above equation.

To the extent that global warming is caused by the formation of greenhouse gases, CTL can reduce these emissions in a very meaningful way. Over half of the CO2 emitted in the United States comes from the combustion of coal, primarily to make electricity. The gasification of coal in a CTL plant provides for efficient capture and sequestration of CO2. Practically all emissions are eliminated.

Remember how I referred to Fischer-Tropsch fuels as ultra clean? Contaminants in the coal such as sulphur are removed in the gasification stage and, therefore, are not present in the fuel produced by the process. FT diesel has zero sulphur, zero aeromatics and is approved by the U.S. Environmental Protection Agency as non-toxic. FT fuels run the same engines as petroleum based fuels but do so more efficiently, much more cleanly and with less maintenance.

Although the FT process allows the production of jet fuel, gasoline, diesel and petrochemicals, we will concentrate on diesel. Diesel engine technology has been greatly enhanced. To date diesel engines deliver up to 40 percent better fuel

economy than their gasoline counterparts. They are quieter and more powerful than they used to be. They deliver more torque at a lower, and now with FT diesel is also much cleaner.

An automobile powered by FT diesel, one this year's LaMont. As an American I think it would be pretty cool to drive the most powerful automobile, get better fuel economy and still contribute to cleaning up the atmosphere, all powered by domestic fuel.

We intuitively know that if we are importing such a high percentage of our fuel that our military and civil defense apparatus is at risk. Having a strong diversified domestic fuel supply is the answer. And it is a plus that FT is so environmentally friendly.

The coal to liquids program employs domestic miners, engineers, dock workers, fuel distributors and all who service them. Educators, finance, health care workers, recreation, entertainment, retail. You get the picture. Over time and in order to achieve self-sufficiency we are talking about millions more employed here in the United States. If we are moving all of these energy production workers back to the United States, we will increase local property sales or income tax revenues. We'll talk more about this later.

They said if I wanted to be on the program I had to talk about electrical power, so here it is. A CTL plant will generate a great deal of waste heat. The heat will be used to

operate steam turbines that will provide the electricity needed to operate the plant. There will still be waste heat left over and this can generate low cost electricity to export to the local grid.

I think that you will agree that coal to liquids is in the national interest. Now let's look nearer at home and see what would be the impact on Alaska. AIDEA is working with Chinese Petroleum Corporation in Taiwan and ANRTL of Anchorage to do a pre-feasibility study for a CTL plant in western Cook Inlet. I'd like to introduce Dick Peterson from ANRTL. Dick, will you stand up, please.

This plant would be of commercial scale. Would cost over $5 billion and would produce 80,000 barrels per day of transport fuel and other liquids. Prior to development of such a plant there will need to be attraction to the project of a long term coal supply and involvement by a proven technology provider such as SASOL or Shell, or both. We do not have time today to discuss much about the plant and its operations, so instead I've decided to focus on why AIDEA is involved in this exciting project.

Jobs, production of 2 billion barrels of transport fuels and other liquids, energy equivalent to 6 trillion cubic feet of natural gas from waste heat. Up to 400 million barrels of oil from enhanced oil recovery, state and local tax revenue, dramatic increase in the production of coal, manufacture of

value added products locally, and national environmental leadership.

Construction of the plant would involve about 5,000 jobs. Construction would take several years. Probably four. More important, about 1,300 permanent jobs would result. These are high paid primary jobs that would come with a strong economic multiplier. Whether these jobs are in the mine or in the plant or in electricity production or CO2 enhanced oil recovery, they would have a long life. The plant would have an estimated useful life of 50 years, but because of the high level of maintenance on a plant of this type the real life could be well beyond 50 years.

This plant with the coal around it has the capacity to produce over 2 billion barrels of transport fuels and other liquids. Two billion barrels of product is equivalent to about a 6 billion oil field in place. If it were an oil field and it had 6 billion barrels, that would make it the second largest in the United States behind only Prudhoe Bay.

The plant will make diesel, naphtha and liquefied natural gas. Liquefied petroleum gas. Excuse me. About 80 percent of the product will be ultra clean diesel, 15 percent will be naphtha, and the remainder will be LPG. Only about 5 percent. The products will be shipped to market outside the state. One exception may be a small amount of diesel that would be utilized in rural Alaska due to its non-toxic

characteristics. It is expected that most diesel would find its way to Pacific Coast markets where there is great demand today for ultra clean product.

Waste heat would be used to produce low cost electricity, and this is just the waste heat that's over and above that required to run the plant. In the case of this particular plant that would be 400 megawatts of low cost electricity. That's equivalent to about 40 percent of today's rail belt electricity consumption. The low cost of this electricity could save Railbelt consumers around $1 billion over a 15 year period.

Gas turbine generation at Beluga at the Chugach Electric facility is only a few miles from where the plant would be located. Approximately 12 miles. The Chugach gas turbines are approaching the end of their life cycle five to seven, eight years out. It's relatively inexpensive to go 12 miles to an existing power grid. And if we can get this project moving forward soon it would be a good alternative for electric energy for Alaska.

Enhanced oil recovery utilizing CO2 would prolong the economic viability of the Cook Inlet oil fields by more than 25 years. DOE's recently completed study identified three to 400 million barrels of oil that could be lifted from only six identified oil fields in Cook Inlet using CO2 injection.

At an assumed oil price of $50 per barrel, the State of

Alaska would received 2 1/2 billion just from royalty oil alone. Having an inexpensive source of CO2 available may make some marginal wells economic and add further resources to the Inlet from a renewal of exploration activity.

In addition to the royalty oil revenues the State will receive petroleum production taxes on the incremental oil recovered. The State and borough will receive in excess of $1 billion in taxes from the CTL plant over a 20 year period. The multiplier effect of the 1300 primary jobs in the local economy will generate significant indirect tax benefits.

The CTL plant will use upwards of 16 million tons of coal a year. Alaska's only operating coal mine today, Usibelli, produces, I believe, less than 2 1/2 million tons per year. The consumption of the coal at the CTL plant would be more stable than international export markets that have historically been very price sensitive. Alaska is not a low cost coal producer.

For those of us that have been involved in economic development in Alaska the concept of value added is the holy grail. It is quite distressing to see logs exported in the round, crude oil shipped to refineries out of the state, fish processed at sea, and zinc concentrates and other minerals shipped to a smelter somewhere else. On the other hand, it is gratifying to see a refinery at North Pole, or a fertilizer LNG plant in Nikiski. That these jobs are very meaningful is

demonstrated by the efforts to keep Agrium open that you've all heard about the last two days.

Besides the value added from the products already mentioned at the CTL plant we can look at the experience of SASOL in Segunda, South Africa where they have operated CTL continuously for over 50 years. In Segunda they manufacture over 150 products from the CTL production. Just about everything petroleum based from jet fuel to lipstick.

Our nation needs to impede global warming and clean up its air. Alaska needs to escape its status as being the poster of the day for environmental opposition to commercial development. In my view it will be of immense benefit to Alaska to show the rest of the nation how to produce an ultra clean fuel in the most environmentally sensitive manner.

We possess the necessary attributes to demonstrate to all America that coal can be combusted without emitting great quantities of CO2. That electricity can be generated from coal without greenhouse gas emissions. And an ultra clean diesel fuel can be used in automobiles, trucks and buses made from a plentiful domestic source.

Alaska is in a race with other domestic coal producing regions of the United States for the first world class CTL project. There will be smaller projects built but Fischer-Tropsch is a process that requires scale from a maximum economy. We face competition from Powder River coal, Montana

coal, a lot of domestic coal. Outside of the U.S. there are projects in various phases of readiness in China, Australia, India, and others with abundant coal resources.

We have competition from areas that have stranded natural gas such as Qatar and Nigeria, who are doing Fischer-Tropsch gas to liquids projects. All of this activity has strained the manpower resources of the only two technology providers with world class operating experience, SASOL and Shell. At first there will only be one or two projects in the United States. Even though the U.S. has one-quarter of the world's coal resources, there simply aren't enough technicians and engineers to start up an unlimited number of plants.

I don't have time today to go into the economics of why Alaska can win this race, but please rest assured the race will be won on economics. And Alaska's economics are very attractive at this early stage. Obviously from what has been outlined above we have much to win and look forward to your support. Thank you.

COMMISSIONER SEAMOUNT: Thank you, Mike, for speaking about such an exciting project.

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STEVE DENTON

COMMISSIONER SEAMOUNT: Our next speaker is Steve Denton. He is vice president of business development for Usibelli Coal Mine, Incorporated, located in Healy, Alaska. He has worked for Usibelli for about 19 years since 1972 holding jobs of laborer and equipment operator, vice president engineering and general manager prior to his current position.

Between 1987 and 1996 Steve was self-employed as a mining and civil engineering consultant in Ketchikan and Fairbanks, serving the mining, construction and logging industries. Steve is a graduate of the University of Alaska with a Bachelor of Science in Mining, Engineering, and is registered as both a mining and civil engineer in Alaska. Please welcome Steve.

MR. DENTON: Well, I'd like to thank the AOGCC for having me today and for putting this forum on. It's quite refreshing to me to see a little bit of proactive action going on the part of our regulatory bodies to try and deal before the -- we hit the cliff. Although I don't really think we've hit the cliff yet, but at least to deal with the issue before we hit the cliff. And I believe that coal has a role in that.

I'm going to tend to focus on the electricity and how electric generation can help to alleviate some of the stress on the gas resources in the Cook Inlet Basin. You've heard from Agrium about how using coal to produce fertilizer can relieve

one piece of it. You've heard from Mike just now about how coal could potentially be used to produce one of the cleanest fuels known to man. But I'm going to focus on the electricity piece of it.

Before I do, however, I do want to make a comment about the gas supply and one other possible addition to the gas supply option. That is gas supply from some new fields and from some unconventional resources. Usibelli Coal Mine, we would like to try and think of ourselves as an energy company now that we're pursuing natural gas development in the Nenana Basin, as one of the partners in that activity. We also have about a 200,000 acre exploration license before the State of Alaska right now in the Healy area. And that would be driven somewhat by desire for coal bed methane. But there's also depths of sediments there that some potential for shallow gas. Certainly not in the kind of volumes that we would expect in the Nenana Basin or Cook Inlet, but certainly there is some potential there.

However, last week we got a pretty swift kick to the groin on that particular ambition by our local borough, the Denali Borough. The borough assembly passed an ordinance that basically took about a third of that entire licensing area off the table and with one sweeping vote has essentially I guess condemned, I would say, somewhere in the neighborhood of about 75,000 acres of State resource.

Now they took their cue from the Mat-Su Borough, who did essentially the same thing to the coal bed methane ambitions that were there in the Mat-Su Borough. And the point I want to make is that the local boroughs, the local communities in this state have got to get on board with this if they really want to be part of the solution and not part of the problem. Either that or the State's got to take a no prisoners attitude with respect to defending the State resources. Neither one of those things are happening right now.

So now that I've got that corn kind of slightly wrestled out of my gut I'll move on to the real subject. Coal is a misunderstood fuel. I sure hope I get this one right. And I constantly hear comments from people, many of which should know better, making comments about coal as to, you know, it's not clean, it's too expensive, takes too long to build.

You know, you can go ahead and make up your own list and of course the last one there, the one that really drives me nuts, is that the Healy clean coal project is too expensive. So I'm going to try and address these issues very briefly with some facts that I think, hopefully, you'll find compelling and you'll go out of here with a little bit different view of coal.

The first one is the issue of coal is not a clean fuel. Now I want you to look at this one and it's a little bit of a mystery slide, I admit. If you look at those two things you could probably conclude that for various parameters there's one

or the other that is obviously much cleaner, much better than the other. Now what I'm actually showing you here has nothing to do with pollution from a power plant. What I'm showing you here is a comparison between the water out of the well of my house, SWD, and rain water in Denali National Park.

The point I want to make there is that neither one of us would give a second thought about drinking those things. They're both very wholesome water for you to drink. But the truth of the matter is, depending on what scale you put it on and what kind of background you put it against, one can look much worse or much better than the other. But they're both very acceptable. And I would say that despite the large differences in some of those parameters they really are equivalent and you should not be making the choice about whether you drink rain water or water out of my well based on the, quote, pollutants that are in it. It's really kind of a goofy comparison.

Now if you look at coal again, and here's the real coal one. If you look at coal against natural gas and new source performance standards what you'll see is that in certain areas coal does -- you know, is very equivalent of natural gas. In the area of sulphur, obviously it does much more than natural gas because natural gas has virtually no sulphur in it. But at the end of the day they both meet new source performance standards and the issue of pollution really should not be an

issue in your choices.

The other one is this idea that oil and gas prices are tied to -- or coal prices are tied to oil and gas is one that I get frequently. There's a lot of this, you know, snicker, snicker, nudging in the ribs, boy, I bet you guys are really making a lot of money now with oil and gas prices where they are. Well, the truth of the matter is, is that because our cost of production is not tied to the cost of going out and finding the stuff, it's tied to the cost of digging it out of the ground and moving the dirt to get to it, we can tie our prices to escalators such as the Producer Price Index, or the Consumer Price Index, or those kind of things, that allow purchasers of our coal, utilities, whatever, to sign long-term contracts with us.

We can be pretty certain that we can maintain a fairly even price. Yes, if the price of oil goes up those big trucks burn a lot of oil, our costs go up a little bit and so would the cost of our fuel. But we can sign long-term contracts with confidence that are not totally isolated, but for the most part isolated from the vagaries of the petroleum and the gas markets.

And what you see there is the red and the blue. The red is the average U.S. gas price. The blue is the average Alaska price. And the last date I had was 2004, you can see that the Alaska price is headed for that 3.50 mark which is

about where it is right now. It's continuing that upward trend. And then the green and the brown are the two coal price lines. The green being the U.S. price and the brown being the Alaska price. And you can see that they track fairly close together. So coal does not fall with oil and gas prices.

The other one is that coal plants are expensive to build and operate and, you know, that seems to be a real prevalent thing. This graph here shows on the left the average retail price of electricity and all the states are platted on there. And then the bottom of the graph is the percentage of coal and the generation mix in that state. Now admittedly there's a lot of power trading back and forth across state lines, and whatnot. So despite the fact that there's almost nothing going on in California or some of these other states in the way of coal generation, they do buy some across the fence. But I think it gives you a good look at what it really means if you put coal in the mix.

And in Alaska coal is grossly under utilized right now. That's not to say that natural gas, electricity generation doesn't have a long term and a very important place in that electric generation mix in the Railbelt, but it's grossly under utilized in the Railbelt right now. And we're paying the price of it. We've got some of the highest electricity rates in the whole country. And I would maintain to you that that's kind of ridiculous. We've got the lowest energy prices but the highest

electricity rates. Now that just does not make any sense. And we have the resources to deal with that.

Another one I hear frequently is this idea that, you know, we're such a small system up here. You know, we only need, you know, 250, 200, I'm not sure exactly what the number is but we've got close to 1000 megawatts generation capacity in the Railbelt. But during the summertime when it's light all the time obviously the demand goes way down. And I constantly hear this from utility managers that, you know, we just can't build these big -- you know, this coal capacity that you're talking about because we can't base load it. It has to be base loaded or it's not economical. Base loading means that you run it as close to 100 percent capacity all the time as you can.

So I went back and I ran a little simple model. This is my model. I didn't get it from anybody. I'd be happy to go through the details with you, but it's pretty straight forward. It basically says that you've got capital costs which is fixed, and if you produce less megawatt hours then you're going to have to do a higher capital charge against the plant. Your labor is fixed. You're not going to send all your people home, so if you produce less megawatts hours per hour you're going to -- that's going to be a fixed cost and then certainly a percentage of the other O&M is fixed. The only real variable cost in there, the significant variable cost is the fuel. And so when you put all those together and plat for 100 percent

capacity out of the plant versus 50 percent and draw a curve, this is what you get.

And what it says is that starting at 100 percent capacity about $3.50 for natural gas is about the break even point for a new plant. As you start to turn those plants down your price will go up because of fixed costs for both plants. It's a little bit flatter for coal because coal turns down better than gas plants do, than turbines do when you get down to those kind of turn downs. But because of the high fixed costs of the coal you start to creep away from gas at 3.50.

At $5 coal is more economical at all options. And if you're talking about something like burning naphtha in North Pole, I mean you just blow the economics completely out of the water at any range of operating parameters. So that's really a false concept. You could easily build a coal plant now that was twice your base load, you'd still be ahead of the ball game, and over time you would eventually take all that extra capacity up.

Finally, the Healy Clean Coal project is too expensive. And that's an interesting one. That was probably true in 2000 when gas was still $1.35 or $1.25 million Btu in Cook Inlet and most of Fairbanks needs, for instance, could be taken care of by the intertie. I don't think that we're ever going to see $1.25 a million Btu gas in Cook Inlet again. This is a situation that exists today. The situation that exists today,

I didn't make up these numbers, I just pulled them off of public filings with the Regulatory Commission, or out of reports.

And the first report there, the 2001 Duke Report was done for Golden Valley and AIDEA in 2001. Was managed by Golden Valley, so I think I have to accept the numbers as something that's dependable. And the conclusion of the Duke study was that there were two options to operating HCCP. One was to retrofit it with conventional technology. The other was to do what they call a limited retrofit which would utilize existing technology and take care of what they call system deficiency. This was things like the excessive wear on the mill exhausters. So by taking care of these system deficiencies they concluded that both options, including the limited retrofit, could operate safely, reliably for a long time in a commercially normal sort of fashion. That was the conclusion of the study in 2001.

They also concluded that the power could be produced and I would say that that was loaded a little bit because I know of a few things in there that were flat way high in their estimate. But nonetheless, they did the estimate, they escalated it for six years which puts us pretty close to today, and they came to the conclusion that six years from 2001, or in 2007 it should cost about 6.3 cents a kilowatt hour, $63 a megawatt hour.

If you look at what it's costing at North Pole right now to either burn number 4 diesel Hago (ph), or naphtha in the plant that's about to start up, you're going to be in a position where you can save somewhere in the neighborhood of about $80 a megawatt hour for every megawatt hour of generation that you would displace with the Healy Clean Coal project. Run the numbers. It's about $30 million plus a year the ratepayers are paying right because Healy Clean Coal project is not running. That it's too expensive is just plain baloney.

And, finally, I'd just like to end with which fuel is best. I'm not up here advocating that we try and, you know, totally turn the Railbelt into a coal only operation. We've got a wide variety of resources and they all have their place and their good attributes. We need to look at what makes the most sense from the standpoint of benefits to the consumer.

And I would say that benefits include things like industrial uses. If I have to put a hierarchy of uses for natural gas, I would put electricity production as the lowest priority because it brings the least benefits once those prices start climbing up to where you can do it cheaper with coal. It brings the least benefits to the consumer. And certainly threatening basic industries because you're consuming natural gas to make electricity is not a smart way to go.

So I just hope that what comes of these kind of sessions is a step back and to take a fresh look at the

resources that we have and what is the best way to use all of them and not tend to focus on just one. Thank you.

COMMISSIONER SEAMOUNT: Well, thank you, Steve. I guess what you're really saying is you really don't get another day older and deeper in debt.

MR. DENTON: Well, I don't know about that.

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ROBERT STILES

COMMISSIONER SEAMOUNT: Okay. Our final speaker on this panel is Robert Stiles. He's president of DRven Corporation. It's a development company based in Anchorage, functions as a project development manager of the Chuitna Coal project, a Greenfield coal development located in the Beluga coal field of South Central Alaska. DRVen Corporation also functions as a director of the Chuitna coal market development programs.

Mr. Stiles has over 30 years of experience in development of western U.S. natural resource projects with approximately 20 years of that experience devoted to coal development in Alaska and market development for Alaska coal. Mr. Stiles is a past president of the Resource Development Council and president of the Alaska Coal Association. The trade association of the Alaska coal industry. Mr. Stiles also serves as co-chair of Arctic Power.

Mr. Stiles holds a Bachelor of Science degree in Aerospace Engineering from Texas A&M University. Let's welcome Mr. Stiles.

MR. STILES: Well, good afternoon. It's always good to be the last speaker on a given panel because you can always shorten what you're going to say to try to get everybody back on schedule. And so we're going to try to do that. I've got what I think are some very provocative slides. Which one

do I push? And the first one of those is the picture of my granddaughter who won the Miss Teen USA pageant on August 15th. Any observations of that it's clear that she overcame a polluted gene pool. But let's get on to business.

Just a quick outline. We're going to look at sort of a public information knowledge base with regard to coal based generation, draw some broad conclusions from that. Look at some fuel prices on a snapshot basis. And then what's the bottom line?

I'd like to thank the folks with NETL, and as well the folks with the Alaska Energy Authority. I think they have done extremely good work, and their contractors, in terms of kind of capsulizing the power situation that we face in South Central Alaska. That's important to me as an individual consumer of power, it's also important to me in terms of the development of the project that we're working on, which needs about 50 megawatts ultimately.

We got three kind of key pieces of information. One is the Railbelt Energy study completed in January of '04. The South Central Alaska Natural Gas study that was done in June of '04. And the South Central Alaska Gas Needs Assessment. I couldn't find the final report. I understand it is actually out. So I was working off the draft.

From that you can draw some broad conclusions. Coal fired generation is needed in South Central Alaska sometime in

the 2012 to 2015 time frame. That comes to a large extent from the energy task force study that was done by Alaska Energy Authority, was done by R.W. Beck. They clearly identified the need for some coal based generation. Possibly one plant in South Central, another in the Interior.

Base loaded coal fired plants produce the lowest cost of power. Steve showed you a slide there that had the various states around the country and what their power costs were. And if you will notice it was clear that the more coal fired power generation you had, the lower your power costs. And gas fired and renewable resource generation all are extremely compatible with, and important to the generation system. You need a mix of generating options for reliability and efficiency.

And with that let me give you just a quick snapshot of prices in cents per million Btu. Now one of the problems that you always have in dealing with this stuff is coal is always quoted in dollars per ton, natural gas is quoted in dollars per Mcf, which is about equivalent per mean Btu, and oil is always quoted in barrels. Well, the common denominator among all of those is what's their value per million Btu?

The two numbers that -- I can't even read the ones I've got in front of me, much less over there. On the left you'll see the thermal coal prices. On an international basis $2.67 per million Btu. And there's a footnote down there that I really can't read. That's actually CIF, which means delivered,

which is the way that all of your oil prices and most of your gas prices are delivered to some point. CIF Amsterdam. FOB port of departure, it's $1.97 per million Btu's. So you can see the effect of the transportation costs on coal. I think that's about 70 cents. or almost a third of the delivered price is tied up in transportation.

In the Lower 48 from mine mouth, or near mine mouth power plants the landed price at the power plants is somewhere in the range of $1.10 to $1.30 per million Btu. If you look at gas, natural gas Henry Hub, and this was September 16th, it was $5.09 per million Btu and the NYMEX Futures for September of 2007 had it at about $7.44. And what you'll notice, particularly if you look at the mine mouth and you compare it to the delivery prices, that coal on a cents per million Btu basis is a quarter or less of what the price of gas is.

Well, what's the bottom line on that? This is the bottom line. If you look at this graph on the right, I think I understand it since I did put it together. And there are some errors in it but the errors tend to make it more striking. What I did is I looked at -- and what happens is that the green line, which is the gas price line, actually moves up. But this is just kind of a simple minded comparison. On the left is the power cost in dollars per megawatt hour. On the bottom -- what is that on the bottom? Oh, that's return on capital. And the band represents a band in prices per million Btu of coal

compared to a band of prices in natural gas. And what you see here is that the bands intersect at about $4 per million Btu for gas and coal in the range of $1.20 to $1.45.

Now if I went back and corrected some efficiency factors in there, that intersection point would probably be around $5, and nobody really believes that we're going to be getting $5 gas any time soon. So it seems very evident that coal is going to generate the lowest cost of power. What the net effect of that has is that if you use your gas and you use your renewables, which are very -- well, renewables are very capital sensitive, gas plants are very fuel price sensitive in terms of the power cost. So what you use is you use your coal for your base load and you use your gas and your renewables for peaking. And you get a highly reliable balanced system in that respect.

Now there's some major challenges to coal fired generation in Alaska not the least of which is capital accumulation. They are more expensive than a gas plant. But that's the bad news part. The good news part is that's a fixed cost that extends over a long period of time. It doesn't change. Coal prices don't change dramatically. They'll change dramatically if the fuel prices go up, but not the coal itself. And fuel for trucks and vehicles and equipment and that sort of thing is a large part, a substantial part of the overall production cost of coal.

One of the other challenges is clearly the environmental and permitting challenges. But probably one of the most dominant one is a commitment on the part of the generators and the major users. Now Harold used the word cohesiveness. A lot of guys use the word alignment. And what that means is that they need to get their act together. In a system where liability and flexibility requires a mix of generation modes, gas, renewables and coal. And I almost got us back on schedule. I'll be glad to answer any questions about my granddaughter. Thank you.

COMMISSIONER SEAMOUNT: Thank you, Bob. Well, that concludes the coal power panel. And I believe we're going to take a 15 minute break or a 10 minute break and we'll come back with the round table discussion.

(Off record)

(On record)

CHAIRMAN NORMAN: First of all, let me ask can everyone hear me? It's a little hard here to tell whether you're hearing. Mark Edwards, are you able to hear all right in the back? Good. Okay. If any of you at any time have trouble hearing just hold up your hands or wave and that will tell the speaker to move closer to the microphone. And also we haven't really tested these microphones and I'm thinking that out of one there's bound to be one that's not going to work. So what we'll do is move it and pass it around. But

theoretically each of the microphones for the panelists should work in front of you and if they don't why we'll go to a fall back position.

The forum that we will follow right now. We have some very knowledgeable panelists here and we're going to want to hear from them. And we'll pose a question and give each of them some time to respond. Following that we will then have a microphone and we'll ask for people in the audience. And if you have any questions that you'd like to pose, or if you have a comment, and we'd ask you to keep it brief in respect of everyone else, but if you simply have a comment that you'd like to make, that's acceptable also.

The panelists before you, I believe that you -- if you weren't here -- maybe perhaps I should go down the list. I'm not going to give a full introduction because most of them have received a full introduction already in advance of the excellent presentations they've given.

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CHAIRMAN NORMAN: But to my right, to your left, is Michael Munger. Mike is executive director of the Cook Inlet Regional Citizens Advisory Council. He's held that position since 2003, after serving two years as that organization's director of operation. Mike brings over 32 years experience working with the oil industry in Alaska, both in Cook Inlet and the North Slope. He worked for the Alaska Department of Environmental Conservation for 1989 to 2000 during which time he served as an environmental specialist responsible for regulatory oversight of all Cook Inlet exploration, production and refining facilities.

To Mike's left -- stage left, stage right, to Mike's left is Bill Popp who by now should be well known to you. The only thing I'll say as we go by Bill is he has been a tremendous help in the formatting and planning of this program and we are very much appreciative of that.

Carolyn Dunmire gave an outstanding presentation this morning and was introduced and we'll hear more from her in a moment.

To my left is a gentlemen I want to thank. He's recently made a change in his position but he was scheduled to be a panelist and he kindly consented to stay with the panel. He has a wealth of information and a unique perspective on this that we need on the panel, and that is the perspective of

someone in charge of running a major utility.

Tony Izzo joined Enstar in 1999. He was at that time vice president of engineering and operations. He was appointed president, CEO in March of 2001 and served in this capacity for over five years. He left the company very recently in this month and he has worked in the natural gas industry for over 25 years.

Mr. Izzo currently serves on the board of directors of the Anchorage Chamber of Commerce, the Anchorage Economic Development Corporation and the Western Energy Institute.

To his left is John Zager with Chevron. To his left Harold Heinze, Scott Jepsen and Tim Johnson with Agrium. That will complete our panel. I think we have a very interesting mix of different perspectives and knowledge, and I'll start out, first of all, I want to tell all of you we will finish on time at 5:00 o'clock.

I will start out now by posing a question that in my mind I'm 99 percent there, and a question for each of you will have two parts. First of all, do we here in South Central Alaska, the Railbelt, do we have an energy, call it problem, call it challenge, call it prices, but is there a problem? And if your answer to that is yes, we do have a challenge to be confronted, then what solutions or suggestions can you offer for confirming it.

And Carol, if you don't mind I'm going to -- while all

the others are thinking, you seem to have the most nimble mind and can come up with 16 solutions to the problem, so we'll start with you, please.

MS. DUNMIRE: Thank you, Commissioner Norman. Can anyone hear me now? Now? Okay. I'll just talk loudly.

Yes, I believe there is an energy problem. I don't think it's quite a crisis. I don't have the expertise as a geologist to say that what the future gas supply looks like, but from my perspective, hearing from the producers yesterday, they clearly are seeing lower production levels. So the trend is downward. And I think that that is one sign right there.

The other thought that I think hasn't come up as much is that a very big portion of the infrastructure for Cook Inlet Energy is reliant on natural gas. And that is always tenuous in any location or environment, that to have all of your energy reliant on natural gas is not good. That there should be some diversity in supply. And so what I would be looking at is other types of energy sources. And I think that as far as the solutions and all the different options that I looked at there's a couple things that need to happen right away.

First of all, Alaska has some very unique resources that other people throughout the world and the U.S. are not going to do the primary research or demonstration projects that need to be done to prove the resources for Alaska. Mainly those are geothermal and tidal. So if you want to pursue those

resources here in Alaska we need to do the research here. And so those -- the money, the resources, the people, the expertise needed to develop those resources needs to move, happen here. And I do think both tidal and geothermal show quite a bit of promise and that they deserve some time, money, dedication and demonstration projects. So that's one angle on it.

The other is that there has been a lot of effort and money and research dedicated to natural gas pipelines and routing and volumes and potential. And that there are other resources such as coal and hydro that deserve equal attention.

And the coal presentations were quite good and the coal resource here looks to be quite extensive. But one thing that's getting overlooked is the infrastructure to move the coal out. There are several possibilities from mine mouth plants, however these mine mouth plants, the mines are located right next to national parks. And so there are air issues that could be a problem. And also delivering coal to something like the Agrium plant requires infrastructure.

Now the coal companies will happily get the coal out of the ground and Agrium will happily receive it. But someone needs to move that coal from the mine to the plant, or the user. And that infrastructure needs to be developed. And that's something that Alaska is going to have to do itself.

So there's a couple of issues that need to be taken care of now that no one else is going to take care of for

Alaska. And so I think those are the things that need to be looked at regardless of whether there's a spur line built or not, because of the diversification in energy supply that will make it more secure across the board in the future.

CHAIRMAN NORMAN: Thank you, Carolyn. We all of you able to hear Carolyn all right? If anyone that couldn't hear her, hold up your hand. Okay. I'll talk it then that you are able to hear, particularly those in the back of the room. If you have trouble hearing hold up your hand because we haven't tested these microphones.

Bill Popp, same question.

MR. POPP: Well, John, I've kind of wrestled with this one today, as you told me what the question was going to be in advance and so I should be more prepared. But this is an extremely complex situation that we're in.

And do we have an energy problem? Well, maybe. I mean obviously supply issues are what supply issues are. I think we do have a problem in terms of local sources of crude oil and natural gas. Any time you can develop the resource close to the end users, everybody wins. The producers pay less to deliver the product, the end users pay less to get the product. And, you know, as I tried to explain yesterday, we have a refinery capacity situation in this state that is very troubling. And it could have incredible ramifications if there is a supply interruption of crude oil to several of our

refineries in this state.

And, you know, the belief that world capacity can make up the slack on that I think is a belief that needs to be looked at very closely today. Because I don't know that that's true any more. And that can have severe ramifications to our economy. And so obviously the Kenai Peninsula Borough encourages and supports more local exploration.

I think we've seen a positive message over the last two days from any number of companies who are talking about new plans to come in and explore and develop. And I think that that is a bright outlook for the next few years. But it doesn't mean anything if they don't find anything other than a short term gain on the cost of the exploration. So we have to cross our fingers and hope that they know what they're doing and that they can find those resources and bring them on line.

As far as the issues of our current energy supply picture, where it's going over the next decade, two decades, 50 years, I think we are in a transition from a fairly easy system that was developed because we had just an overflowing amount of gas in the Cook Inlet Basin that has developed a very significant expensive infrastructure to produce, deliver and consume natural gas in the Basin that can't be discarded out of hand.

I get very frustrated when I hear people talk about well, just shut down a couple of plants. That's probably one

of the dumbest statements I've ever heard in terms of its ignorance. And that's a problem for policy makers to educate the public on these issues.

We are in a transitional phase. We are working our way towards diversifying our energy mix, and rightly so. And we need to make some very tough decisions over the next two to three years as far as the investments, and they are going to be significant, that are going to be made the energy grid for power generation, for heat, and for the related industrial base that makes those systems cost effective for the consumer. And we have to make smart decisions.

And I think it's going to require a unified policy between the federal, state and local governments. We've got to work together on this. And, inversely, I think that we need to solve some of the smoke stacking and boundaries that are being drawn between a lot of the utility entities and between industry and between the producers. I think that there needs to be a more candid dialogue between all of those players to come up with a more uniform front in terms of how we go forward here, instead of scrabbling for the scraps which I think some are prone to do. And I think that's a risky path to follow if we continue to follow that path.

You know, I've heard, you know, comments on both sides of the fence that there's plenty of resource to be found and that the markets will balance themselves versus those who are

concerned that we need to discard the past and move on to the future of different energy supplies. And I think the truth lies somewhere in the middle. But it's kind of this Zen question that's laying out there, how do you lay the egg and hatch the chicken all at the same time? It's a little tough.

You know, we've got these transitional balancing acts that we're going to have to do to maintain our existing industries to the greatest degree possible. And not just arbitrarily and out of hand discard them. Yet in the same hand encourage the new industries and potentially the new resources such as the North Slope gas pipeline. And all the while trying to keep the rhetoric out of those discussions and work on the economics, and work together on the policies that are going to make these systems work and to make these projects happen. And to get rid of the one liners and to start having meaningful discussions about the true economics that underlie these various projects and to move forward. If we can't do that then we do have an energy problem.

CHAIRMAN NORMAN: Thank you, Bill. I see our third Commissioner of the AOGCC, Cathy Foerster, has just come in. Cathy, would you hold up your hand? Cathy is our engineering commissioner, a petroleum engineer that sits on the Commission.

Tony, I think you're next in line and you have kind of a unique perspective from the standpoint of operating one of

our major utilities in the area. So I'll pose the same question to you, do we have a looming problem in the energy area, and if so, what solutions exist?

MR. IZZO: Thank you, Commissioner. I guess the simple answer, my simple answer to the question is yes. If someone were to ask me is there a crisis, I'm going to tell you yes, there is. I don't believe that it is one of being able to put the gas in the pipe or keeping the gas flowing in the pipe today or tomorrow, next year, although that has clearly become more challenging during peak periods than it was decades past.

The real crisis in my opinion is one that is economic. As a gas utility operations person at heart, I always think about continuity of flow in terms of maintaining pressure in the pipe. Because if we were to lose pressure in the pipe, if there was a day where there wasn't enough to put in the pipe and demand greatly exceeds supply, then you'd lose that entire system. And you'd probably be talking about a crisis unlike anything that's been discussed the last couple days. Because the crisis would be the requirement to take down that entire system.

That means shutting off half the state's population, going home to home, literally shutting off that meter. It means testing. Some of that is hydrostatic testing so you've got to introduce water into the system, pressurize it. Once that's completed and all of those tests are passed you

reintroduce gas. I got a couple folks in the back, friends of mine from Homer Electric are laughing.

I told them this story at lunch time and so they're smiling at me. But you could see where it could take months to reintroduce gas to vent the air out of the system, and then to go to each of the half the state's population homes again and reintroduce it. So from a gas utility perspective is the reason I mention this story. That's why you get some heightened anxiety, heightened uncertainty, and stress that will come from that perspective. Because the minute there isn't enough flow you're talking about a winter without heat. And that would be a disaster.

The economic issue, I think, is the one that's current. We saw some prices that went up yesterday. We've seen a series of price increases over the last few years, 14 percent, 17 percent, 19 percent. I think I saw something like 29 percent. I'd have to recheck the numbers that were presented yesterday for 2007. And so it comes down to having to make choices.

There are some very difficult decisions ahead. And the energy industry, as most of the E&P folks here discussed over the last day and a half, it's long lead time. You can drill 10 wells and you're lucky to hit one. This is a capital intensive long lead time industry. So for a utility you really need to have some direction. Where are things going to go? And in terms of solutions, that's what we need. We need leadership.

We need to understand from a state wide perspective where are things going, where are they headed. Is it a spur line? Is it LNG? Because you can't throw all your eggs in one basket and then find out later on that you missed it. Because the options for alternatives don't exist.

So I guess in closing, solutions or things like what Harold Heinze talked about, a spur line, incenting E&P activity, absolutely critical. Keeping the industry that we have alive, absolutely critical. Thank you, John.

CHAIRMAN NORMAN: Thank you, Tony. John Zager, same question.

MR. ZAGER: Thank you, Mr. Commissioner. Well, I'm an E&P guy so I'll probably take a little bit of an E&P slant on this. But, you know, I'd say do we have a crisis? Probably not. But I think we might have a deliverability crunch here. And we got some big issues to address in the next few years. So when I'm looking out five to 10 years, that's kind of the time frame I'm operating in. And a lot of these things we've been talking about won't get here for five or 10 years.

So when I'm in the E&P business there's two sets of risks we're used to handling and there's the geological risks that are common in the Cook Inlet. They're common in the Lower 48. But we also got something here called market risk which adds.....

CHAIRMAN NORMAN: Pull the mike up.

MR. ZAGER: I'm sorry. So in the E&P business we basically have got two types of risks. We've got geological risks, we'll just call it. And that's present in the Lower 48, it's present up here and that's where we're used to dealing with it. But this is probably the only place in the U.S. where we really have significant market risks to deal with.

And that's, I think, as was expressed earlier this afternoon, a real uncertainty for players. Now some of us are established with markets here. And that's good. We have large fields to work with and draw on and grow our production. We also do an exploration. But especially for the new players coming in I think they really got to think hard about this market risk. Because your obvious markets are Agrium. But they really can't assure anyone they'll be here past next year right now. So if you kind of drill wells and look at bringing production on in five years, four year, you got to be thinking out there.

You've got potentially the LNG plant as a market. They can't really assure you they're going to be here beyond 2009 right now. And in that scenario you've also got Enstar and the utilities are pretty well supplied, especially if either of those other markets go down. So it's about the market. You got to be able to follow the dollars and figure out how you're going to get a payout here.

And to the extent we're talking about options like the

spur line, that's another big uncertainty you'd have to deal with. If that comes in it would certainly be competition for the market, potentially displacing the market and putting another whole risk into your exploration program. You've got to try to anticipate today how you're going to get paid out on exploration programs.

So we can talk a lot about getting more exploration but there's some significant barriers there that generally in the U.S. you don't have to deal with in terms of market. In the Lower 48, you have a discovery, you hook it to a pipe and basically you're connected to an infinite market. And you'll get the Henry Hub or whatever the local price is based on Henry Hub for that gas.

So long-term solutions? I mean I think we need to definitely keep moving forward with the conventional E&P. It's the direction we're going to have to go for nominally 10 years. What comes in after that will depend partly -- and when that comes in will partly depend on the success of E&P in those number of years. If we are successful in finding hundreds of Bcf or Tcf of gas, then that would significantly delay the need for any non-conventional solution. So we call it for a number of additional years.

In terms of the other options that have been discussed, I think ones that allow flexibility and relative short times to implement are viable. Potentially the LNG import is one thing

I haven't thought about a lot before we came here, but it seems like that's something that could be brought on in relatively short order at relatively competitive prices. So I guess in a nutshell, me and my company, obviously we're going to focus on E&P and bring in additional reserves to market in a timely fashion to meet the market needs. Thank you.

CHAIRMAN NORMAN: Thank you, John. I want to go past Harold for a moment and go to Scott Jepsen and just ask you the same question. Do we have a crisis or challenge, and if so, how do we deal with it?

MR. JEPSEN: Well, my answer is going to fit in very neatly with John's. I think you actually summarized it pretty well, John, from a producer point of view. I guess from my perspective what we really are facing is just a challenge of strategic decisions. We have choices that we can make. One of the biggest ones is do we destroy demand. Do we encourage the fertilizer plant to stay in existence? Do we back an extension of the LNG license to keep the LNG plant in existence?

What happens when you have demand, particularly a demand of this sort, is in essence it creates a spinning spare for the utilities. What happens on a very cold day is gas goes from the industrial users to the utilities. It's hard to say what would happen if you didn't have that kind of spinning spare capacity sitting here today. Tony, in his previous capacity, could always call us up and say hey, Jepsen, we need

gas here, what are you going to do about it? I'd say it's coming your way, Tony. And that's an unwritten sort of agreement that we have. It's one that makes the whole system work. It's kind of license to operate sort of deal.

It's a little bit contradictory to say that we need to keep large consumers of gas in existence to increase supply for the utilities. But as John mentioned, this is a very shallow market. This is not an infinite market like we have in the Lower 48. If you're a newcomer coming into Cook Inlet to look for gas and you find gas, it'd be a travesty if you couldn't sell it. And utilities, by and large, are pretty well taken care of for the next, you know, nine to 10 years. Whereas, of course there's uncertainty about their existence, but if they keep hopping along they'll be out there to buy gas.

The LNG market, you know, we could conceivably have spare plant capacity if we go out there and be a buyer of gas on the open markets. We could be the person, the industry, the industrial users could be the people that provide that sort of base load, if you will, for exploration. And then as the utilities need gas you can transition into that higher value market.

This is not something that's popular to talk about. When you talk about these things oftentimes you get people backing away from you and saying that's just not the right answer. And then you also talk about the fact that well, you

know, as John mentioned, the LNG plant could be a transitional operation to either new exploration coming into the Basin or an ANS gas spur line. That's another one of those things people don't want to hear about. It's almost unthinkable to mention importing gas into Alaska.

But what we need to do is we need to keep all of our options open. Those of us in the energy business, we have to deal with uncertainty all the time. Up here you have the uncertainty of market, but you always have to have options to any plan that you lay out. And the problem that I see in Cook Inlet and with kind of the public perception in general is we like to think about one solution that we like, that we're comfortable with and that's always worked. And that's exploration. And that's good. We're going to continue doing development. And I'd certainly encourage others to look for gas, but we have to keep our options open. Back to you, John.

CHAIRMAN NORMAN: Thank you. I think Bill Popp used the expression that what makes this a complex problem is that there are a variety of moving parts to it, and Bill said it's a question of chicken or the egg? Who does what and what can you rely on when you do it to recoup your investment?

And when I was talking with Dr. Arlon Tussing earlier he mentioned the overhang that makes this complex. And Harold, that's why I saved both you and Tim toward the end because over-hanging exploration and production in Cook Inlet is the

possibility that there might be a spur line or there might be very, very favorable results from the project that you're involved in which would change the dynamics here.

So I would appreciate it if both of you could address what you see, recognizing that neither of you can control what's unknown now and the timing of things. But it does overhang the development and exploration of the gas here.

MR. HEINZE: Is that an invitation that I'm next? Let me answer the basic question first. I became convinced a couple years ago that there was a terrible energy crisis in Cook Inlet. And the reason I was so confident was it was based on the decisions I saw people making. Yesterday people sort of almost nonchalantly described curtailing the fertilizer plant. Excuse me, that's a really significant decision. I mean 10 years ago we didn't do that. Five years ago we didn't do that. Something has changed. Something changed.

I'm aware of, for instance, one of the major electric co-ops that would like to replace one of its very old generators. And it doesn't have enough gas reserve for our bankers to loan the money to put in that new generator. Now that's a decision problem that's very significant. It illustrates that there is a horrible gap already in terms of the real world decisions people are having to make. And so I think the problems -- we're well down the road with the

problem. Let me put it that way. The problem has to do with decisions and the things related to that.

I guess it was about a year ago Tony scared the devil out of me when he said if we don't get some more gas under contract pretty quick then in a matter of a couple years I'm going to stop hooking up new subdivisions in the area. I go whoa. I mean those are things that should be taken very, very strongly. And those are things that it's not sufficient, frankly, to say trust me, it'll be okay, all that kind of stuff. This is big stuff. And again, that's why we went to the Chamber of Commerce, we've gone to other people and that's why they've paid attention.

Again, this is not an individual company impact we're talking about. It is an impact on all the citizens of this area. And it affects our quality of life, it affects the cost of living, it affects a lot of things.

So number one, yes, we're in a crisis. Now, what do we do about it? You got a couple things going for you, not the least of which is that almost all the major players have had a wake up call of some type. Again, whether it's Enstar or Chugach or ML&P. They've all to varying degrees had a wake up call. Now they may not have responded to it exactly the same but even Agrium has faced up to it. Even the Kenai LNG plant. I mean it's apparent that there is a decision out in front of us.

The other part that's good is that we have had a number of state and federal agencies that have put a fair amount of resources, I'm just going to say several million dollars worth of work into trying to understand the parameters of the issue. Not to get to what the answer was, but just to put the information out there. And let me give you a few of the simple little examples, for instance. We spent $100,000 to define the options for the Kenai LNG plant. Now I don't own that plant. I'm not going to get to make the decision. But we felt at a time that it became important at least that information should be out there.

We've looked at the NGL issues. And at least made some estimates and those kind of things of things that our reputable contractors, they're in the public record, and people can see them and evaluate them out in the future. That's important because we still need some more help. And for better or for worse, if you hadn't noticed, one of the reasons this crisis has not received a lot of the attention over the last couple years is because the entire political system of Alaska has been distracted by a very big, very, very important issue called a gas line. And a lot of the intellectual resources, the money resources, everything, has been captured and put into working on that problem.

Just look at the time of our legislators. You know, frankly, there's only a few legislators I've been able to deal

with who saw this as a really important problem. And even their time has been split dealing with these other bigger issues. Now at some point here we're going to merge from that and we're going to be able to put more resources and time into some things that are really important to us.

So what do we do? Well, I would argue that one of the problems right now is that we've got an overload of really good ideas. And I haven't heard anything that I would cross off the list if it was me. I don't know enough about anything at this point to cross it off the list. I do know I heard some ideas that were expressed as ideas, not as projects. And I think the only way we're going to be able to come to grips with some of these things is to develop them to the point that we're looking at projects and then people who are really going to make the commercial decisions or the regulatory decisions can weigh in. Because what you have to do is put something real in front of them that they can make some judgment on. Not an idea.

Now I guess just, you know, finally what I would urge is that we find a way in terms of the collectivism of all this, that we find a way to keep advancing as many of these ideas as we can. I think the mistake we make is in trying to compete these ideas and challenge one against the other, whatever. We need to do just about all these things. And I think a realistic appraisal out in the future, the way to success here, is to have done a bunch of these things.

And let's recognize some of these characteristics are different. Certainly I made my living in exploration for a number of years. I understand that to do that successfully you have to be a risk taker. And, frankly, I wouldn't be scared of any spur line ever if I was in that business still. On the other hand, if I am a utility and I have fiduciary responsibility to a whole bunch of customers on the other side of the meter and they write those monthly checks, I'm going to be very careful the types of commitments and decisions I make in their name. And I think that's my responsibility.

And again, in this case I believe that the governments, both state and federal, have a responsibility to help advance the knowledge on these things. Not to try and make the decisions, but to push it forward. So that's where I come from. I think we've got a lot out in front of us. I'm not particularly worried about our dealing with this issue if we are willing to advance many things simultaneously.

CHAIRMAN NORMAN: Thank you, Harold. Tim, from your perspective at Agrium, do we have a problem, and if so, what are potential solutions?

MR. JOHNSON: Well, we definitely have a problem. You know, from the residential standpoint the time frame is further away. But for Agrium it's now. We've already got 50 percent of our plant shut down. We have 80 jobs that have disappeared in the community and from the economy. And so

it is a crisis. It's real. It's the same situation Mr. Izzo was talking about for the residential but at the industrial it's already happened. It's happening now and we're facing it even completely with the shutdown with no gas beyond 2007. So there is a definitely a crisis.

What is the solution? I think that all of the solutions that have been discussed that help incentivize and that continue to promote the exploration for new natural gas resources are important. But with the large abundance of a low cost resource in coal, coal has to fill the portfolio somewhere. We need to start finding a way for coal to become part of the solution, from the power side or even from the industrial side in a project like the one that we have where it can become part of the solution and diversify the portfolio so we're not so reliant. We don't have all of our eggs in one basket.

And I think that as Ms. Dunmire correctly identified, it's a transportation problem too, both from a gas standpoint and from a coal standpoint. Being able to get the resource from where it sits now to where it can be properly used and put in and become part of the solution. So incentives are important. Incentives to keep the companies out exploring and to help and encourage these creative ideas that are out there, to keep them moving forward and to really bring them into a reality.

CHAIRMAN NORMAN: Because Agrium has been identified as the canary in the coal mine, and I think that's probably an apt analogy. We're all in the coal mine together but you're just the first one to feel the problems. And I know this was certainly brought it to the attention of the AOGCC is the shrinkage there. So I'm going to ask a follow up question but I'm also going to say it with the understanding that there may be some things you can't speak to now. But can you give us some idea of what moving from phase one of your Blue Sky project, now this decision to phase two, how much confidence does that indicate that this is a viable option?

MR. JOHNSON: Okay. We can't talk about, you know, everything, but what it means is really that we're still in the ball game and this has been described as we're down from inning one to inning two. There's many steps along the way, but the fact that we're still in the game is a strong indication as we move forward. We're still defining and making sure this is a project that we want to move forward with. And we've said all along that we won't move forward unless it makes sense for us. But as partners come on board and the project continues to advance, that gives a strong indication that this continues to be a very good option for us moving forward.

CHAIRMAN NORMAN: Mike Munger, I saved you for last because all of our other panelists speak from a particular perspective. But there is the public out there and I know no

one person would ever take it upon themselves to say I'm here to speak for the public, but I suppose to the extent that we have someone that's part of your job. So I'd like to pose a question slightly different to you.

Looking at it from the standpoint of the average citizen out there, consumer, worker, resident of this area, to what extent is it appreciated, understood or perceived that there is a problem? And if there is, then what will the public want to be able to implement some solutions to the problem?

MR. MUNGER: That's interesting. And thank you, Commissioner. It's interesting that you pose a question that is more complex than the other question. But apparently I'm the sacrificial lamb for the citizens today.

I think from the general perspective citizens feel there is an energy crisis when they look in the mail box every 30 days and they see the price of utilities going up. And you read about constantly of these shortages and the economic impact on -- well, specifically let's talk about Cook Inlet. As you see the lay-offs at Agrium, obviously you feel the pain when you see the families out of work.

What I want to bring to the table today is the last two days we've seen a lot of potential for further development in Cook Inlet and personally I think that's great. On behalf of my organization, since I speak for many diverse voices on the Citizens Advisory Council.

And just briefly what we are, the Cook Inlet RCAC, we're one of the two citizens advisory councils in the United States and they were formed under the Oil Pollution Act of 1990. And we have 13 representatives on our board that represent the cities and boroughs from Kodiak to Anchorage. And also special interest groups, Alaska Native groups, commercial fishing, aquaculture, recreational entities, environmental groups and also the Chamber of Commerce. And so we are essentially the stakeholders of Cook Inlet.

And I'm not here to promote or discourage development in Cook Inlet. What I'm going to bring to the table today, and it's absolutely imperative, if development does go forward in Cook Inlet, it has to be done in an environmental responsible manner with citizens involvement. We can talk about further projects all day, but without that transparency you're in an absolutely no win situation. As we learned time and time again, citizens must be involved.

And what better way for industry, as they're coming into Cook Inlet, you really have an advantage by dealing with the Citizens Advisory Council. It's essentially one-stop shopping. It's a liaison between all of the stakeholders in Cook Inlet and industry. And we have a real good proven track record of that since our inception which was 15 years ago. So I didn't quite answer the question but I've been dealing with politicians long enough that's the way they do that.

CHAIRMAN NORMAN: We'll accept that answer. We have time now to go back across the panel one time and if anything any of the other panelists said triggered a thought on your part, or something you wanted to respond to, or if you thought of something later that you'd like to add, then we can do so. So Mike, let me gain, you still have the microphone there and while it's still warm, is there anything that anyone brought forth that you feel you'd want to respond to other than what you just said?

MR. MUNGER: No.

CHAIRMAN NORMAN: Bill Popp?

MR. POPP: No.

CHAIRMAN NORMAN: Harold?

MR. HEINZE: No.

CHAIRMAN NORMAN: Tony, is there anything said that you think or anything you'd like to emphasize, understanding this may be your last turn at the microphone for all of you. so.....

MR. IZZO: Sure. Sure, I won't pass up that opportunity. I have thought for some time about the energy issue in Cook Inlet and two words have come to mind. And that is options. We need options. And optimism. And we need some optimism. The options, I think, have been answered over the last day and a half. I heard a lot about options. I'm very encouraged.

One of them maybe I'd like to emphasize a little bit is conservation. I think that conservation has got to be a key component of this all, but I would with caution mention conservation because the way that utility rates are structured they do not -- they're contradictory to their volume base. So it's based on average weather, it's based on average volumes. And so the minute somebody conserves the utility is not earning what it needs to stay in business. We have to be careful that we don't create a problem.

I think there's probably a regulatory issue there that needs to be addressed to encourage a different kind of rate structure that encourages or supports conservation.

In terms of optimism, I really think we're going to need it. And I know I do. As Mr. Munger mentioned, people getting that statement in the mail box every 30 days and seeing rates going up and up, that seems to be the trend. All the information I've seen in the last day and a half indicates we can expect higher and higher energy prices, at least for a little while. And in terms of the overall health of our economy, we need some positive signals.

So we can't throw out any of the options that we've seen over the last couple of days. We shouldn't get parochial about any of them. They all need to be on the table. They all need to be vetted. And we need some leadership from the state level as well as federal to push these things forward. Thank

you.

CHAIRMAN NORMAN: Thank you, Tony. And you gave me an opportunity again to mention this booklet, Conservation is the Middle Name of Our Agency. So I don't want to miss a chance to identify that part of it, although we focused on the supply side. But this is a very interesting simple booklet. We have several hundred copies available. And if you will give your business card to one of the AOGCC staff people here we'll see that you get a copy in the mail.

And at some point we may want to try to, with the permission of the State of Oklahoma, adapt it here. I can see why that was painful for you to say, Tony, because they indicate that if the steps followed here are faithfully adhered to a person could cut their energy bill by 30 percent, which might mean a drop in utility revenues. I say that in jest. But in any event it's an interesting book. We haven't spent much time discussing it. But if you'd like to get a copy of it give your card to the AOGCC staff and will get it to you.

Continuing on, John, is there anything you'd like to respond to or emphasize?

MR. ZAGER: Thank you. Nothing really to respond to. This is my last chance. I just want to say thanks for this conference. And speaking not as the head of Chevron here but more as an Alaskan resident, I hope there's some concrete follow-up to this and that we just don't all go away

from here in the next 30 minutes or so and that's the end of it. So hopefully there'll be some summaries and some actions that come out of this conference. Thank you.

CHAIRMAN NORMAN: I'll address that. Harold Heinze.

MR. HEINZE: Well, there's just really one point but it's sort of two parts. And it's the word expand. I think Carolyn hit it a little bit but I can probably even go broader. We need to think of the options that are on the table and how to expand them. We are not at a point where you start to narrow. We are at a point where you still need to broaden your thinking. There's still things we haven't thought of, we don't understand. Let me see if I can give you the simplest example I can offhand.

There's lots of CO2 on the North Slope. We've heard a lot today about how CO2 could help the recovery in Cook Inlet. Okay? If the CO2 is not going to be used to help the recovery on the North Slope then maybe we ought to figure out something else to do with it. You can move CO2 as well as you can any other molecule. It's no big deal. You just do it.

But again, I don't know if that's the right idea but there's lots of other technologies, other things out there. We need a lot of people thinking about how to make things work.

The second thing is we need to expand the citizenry and the geography of who's involved. We talk about this as a Cook

Inlet issue. Excuse me, it reaches up well north of Healy, probably all the way to Fairbanks, and there's probably also a bunch of other folks in Kodiak and even around in Dillingham that we ought to be worrying about at the same time. And the reason for that is that a lot of the solutions, especially on a broader state level, are going to want to acquire the political system to approve.

I see Murray Jackson back there who works for Senator Wagoner who is a wonderful Senator from the Kenai. But every time he tries to do something he has to answer to a bunch of other senators who don't represent the Kenai or Cook Inlet. And we have to find ways for what we're talking about here in terms of solutions to be good for more than just us.

We may feel the impact right now, but I assure you there's a lot of folks out there who will see this energy crisis deeper and stronger than we do right now in our fellow Alaskans. And we need to make them part of the thinking and the solution.

CHAIRMAN NORMAN: Scott Jepsen, any final comments?

MR. JEPSEN: I've been struggling with what I want to say here. I want to be taken in the right context. I've listened to what Harold has said and some others about needing political guidance and leadership. And I think we have to be careful that what we use that for is to keep the options

open, allow the market to work, and not force a solution on the players. I think that's probably the thing that would maybe not lead to the best solution for everybody.

The thing that I see is we need encouragement to let the market operate, to let the market incentivize the right systems to come into play. I guess if I have two parting words, I guess it would be let's not dictate the answer outside of the incentives to make it work, and let the market work. I think that will probably end up with the best solution for everybody.

CHAIRMAN JOHNSON: Tim Johnson.

MR. JOHNSON: I'll just thank you for bringing us together and for identifying this problem and to create a forum that would look for solutions and to talk about options. So I think it's, you know, as the canary. We appreciate that and to have the opportunity to be here as part of that and talk about possible solutions. And to continue to do that and like John said, to have some concrete action items and to lead this to other things that are of importance to natural resource development in the state from coal to natural gas liquids to the pipeline. That kind of forward thinking leadership. And getting these answers is important. Thank you.

CHAIRMAN NORMAN: Okay. Bill Popp.

MR. POPP: Well, since this may be the last swipe we have, I'm not sure how the time line is going here, I

figured I better get in a few last comments.

You know, I guess my focus is that yeah, we do have to look at options. And we do need to keep all options open now. But we got to start making decisions on those options fairly quickly.

You know, I'll take one case as an example because it's one that Harold knows is very near and dear to my heart, and that is the concept of a spur line coming to the Cook Inlet Basin. And, you know, a little spin up here for Harold from our perspective, you know, God Bless Harold Heinze for being the guy out in front taking on this issue when nobody else is as far as executive director of ANGDA and doing the actual work to develop a game plan for ultimately building a spur line to the Cook Inlet Basin. And these are the type of people that we need to have focused on this issue, and Harold has brought together a great team. And they're doing great work.

But the problem, from my point of view, is how that work is being either ignored or misinterpreted out in the public and amongst the policy making body of the state of Alaska. You know, it's an easy thing to say if you build it they will come. If you build it then all our problems are solved. That simplistic answer does not solve the problem.

We have economic models that were demonstrated today that Chuck Thomas did a great job with his team putting together to show, just as a first swipe, what does it look like

at the end of the pipe when we build it? And how does that control the size of the pipe? And does it even justify the pipe, or the volumes? And that's the kind of work that we as a state should be focusing on right now if we're going to wave the flag of our Alaska gas molecules for Alaskans. You know, it's a great catch phrase but it just doesn't get the job done.

We have a tremendous Rubics cube that we're working on right now and we're twisting it and turning it and trying to get it all to line up where all the colors are on the right side. But if we don't do the work and focus on the work and remember the work when we're going forward on this issue, we have boondoggle written all over it. Now I don't think Harold's going to let that happen. But there does come a point where, unfortunately, it gets a little out of Harold's hands and gets on into the public arena.

And the final piece to that, too, is the industry recruitment piece. That's something you don't hear about very much. Again, that falls into the philosophy of if you build it they will come. I think that to work towards the success, as Harold completes his work on understanding the issue and defining the economic models that are going to make a pipe work to Cook Inlet, there has to be a recognition that then we're going to have to get out there and sell that plan to bring the Dow Chemicals to Alaska, to bring the major -- you know, the Shell Oils with their chemical operations, Chevrons, all the

major chemical manufacturers to point out the fact that maybe we do have a wet gas stream coming to Cook Inlet that's got a significant piece of ethane or propane that can be made use of here in the state.

We have challenges on that front though because what do we do with it? You know, we've heard comments talking about the fact that the Pacific Rim markets where we might sell those polyethylene products are glutted because we're going up against China. Now I don't know if that's true or not. But, you know, we have to understand this issue and understand the markets that we're going to try and serve with such hype like that before we can throw out the one liner if you build it, they will come.

And I hope that that's something that's carried away from this conference too, is that this is not easy. And there are no easy answers. And it's a disservice to the public to throw out easy answers to such a complex situation. And I hope that folks will take that to heart and recognize that when they leave this conference and go forward.

And again, finally, I hope this conference means something in the greater scheme of things to everybody who's attended over the last two days. Because there's some great, you know, information that's come out of this and hopefully we'll carry it forward into a broader dialogue that leads to a lot of the solutions that we're seeking.

CHAIRMAN NORMAN: Okay. Last call for those up here before we go for public comment. Anyone else have any final thoughts? Then we're going now to take any questions or comments from those of you that have been with us. Hold up your hand. We have the AOGCC's miniature version of Phil Donahue here with the microphone and she'll come up and stand up. And please try to be as succinct as you can in the question. And if you have it for a particular member of the panel, indicate that person to whom you're directing the question, please. Dave?

MR. HANSON: You can hear me?

CHAIRMAN NORMAN: We can hear you fine.

MR. HANSON: Okay. Dave Hanson, economic director of the Matanuska-Susitna Borough. I just want to make a quick comment and that's that I think what Bill just said and what Harold said is right on the money. That maybe crisis is the wrong word. But we're on the lip of a downward spiral. If we don't recognize -- we don't want to have the solution to our gas supply problem or energy supply problem be any home grown industries going out of business. Then we're on the lip of a downward spiral. And so I really compliment you on bringing that out and compliment the whole two days on making me much more aware of what's happening. Thank you.

CHAIRMAN NORMAN: Hand up if you have a comment or question. Yeah, Bob Loch with VECO.

MR. LOCH: And the question is strictly from a personal perspective of being a homeowner so I'll try and set aside, you know, we all would like a gas line. And this is the panel, I've got to commend everybody it's one where everybody is right. But I had a question after attending several of these forums and I think maybe Tony's the guy to answer it, I'm not sure. But setting aside for a minute that we all know that jobs in Kenai are important and all that, you know, if we were to get a gas line, you know, as a homeowner am I competing with the Agrium Fertilizer Plant for every cubic foot of gas I buy? That's question number one.

And you know is that the highest and best use? Well, it certainly is for people in Kenai. And the point being that, you know, at what point does the gas become expensive enough so that it's no longer viable, and then when that happens does that reserve double for people like me who, you know, just heat our houses with it? Certainly that is going backwards and I don't believe that that's the way we should be going. We should keep our options open, etcetera. But I was just curious if that's -- how those dynamics work.

CHAIRMAN NORMAN: I think that's an appropriate question, Tony. Can you.....

MR. IZZO: Well, I think, unfortunately, we are competing. There has been no issue within the industry itself in terms of setting priority. I don't want to speak for

everybody up here but I believe you'd get a similar answer in that if it's a really cold day and we have choices of where it's going to go, do we shut off my home, your home, our homes whether you're in the Mat Valley or on the Kenai Peninsula. But that's going to be the last thing that happens. The LNG plant gets curtailed, that Agrium gets curtailed. Agrium was curtailed just last winter for weeks because it was cold. It was 10 below zero.

Secondly, is it too expensive or when does it become too expensive? Very difficult question to answer on a personal basis. I think it comes down to what will the market bear. Right now I understand that gas delivered for a million Btu this year is $6.70. The next alternative being fuel oil is -- I believe the slide was $18 and change. So I think that's the range that we're working in.

As Harold said earlier today, made the very good point that really, it's going to take a lot -- you have to add that inconvenience factor of do I really want to incur the expense to convert my appliances and put an oil tank outside or refill a propane tank, etcetera.

CHAIRMAN NORMAN: Question? Oh, I'm sorry.

MR. HEINZE: Just real quick. The Department of Energy, and I don't know if Charles is still here, they've looked at different prices for different uses. And as you might expect the residential market clearly survives to the

very end of the curve because it can afford to pay the highest price by a considerable amount. But again, your question really is, is demand destruction taking place out there right now as prices are going up, and the answer is yes.

CHAIRMAN NORMAN: Thank you. We've got hands up over here.

MS. STONE: Thank you. I'm Denise Stone from Benchmark Oil & Gas and I just want to make a comment or two about a few things that had me squirming yesterday. And one of the things that has been used here as a tool for illustration is this gap diagram. And as an explorer I just want to make a few statements about that. Every basin in the world has a gap diagram. You've got production that's either peaking or growing, whatever. But most basins that have been producing for a long as say the Cook Inlet has, and I'll use the North Sea as an example, producing since the '60s, it's got a downward production story and consumers are, you know, consuming fast. And then you have this gap.

Well, that's going to be the case in many, many basins in the world today that have been on production for as long as the Cook Inlet has. So I guess the cautionary word I would offer is that it's the nature of the diagram itself to be negative. There is no clairvoyance, there is no, you know, future field sitting out there that's going to correct that diagram to get it to look the way you want it to without doing

more drilling and knowing what the future holds. But I'll just offer that up as a way to put that diagram in perspective. A lot of basins have those diagrams. Personally as an explorer I think they are management tools to get you to work harder. That's the nature of the business.

I'd also like to say that the way the diagram's been turned around is through technology and more drilling, is typically the way I've seen it happen. If you throw more money at it, prices go up, you let the market work, the prices go up, and you're able to get your business going in a way to accommodate demand. And I think that that will happen in the case of Cook Inlet, probably in the short term. In, you know, five or six years at least.

The other point I wanted to make is, you know, you need to realize as a state that you're not alone. You know, referring I guess specifically to Cook Inlet area, that this is happening in a lot of places in the world. And the example that I would call on as an analogy that's probably magnitudes bigger than the Cook Inlet area is the U.K. and their production in the North Sea that's been declining, you know, really rapidly. The off shore, the expenses of doing business in the off shore in the U.K. have dropped and the incentivization has gone up to get more companies to explore.

You know, if I was tackling this problem myself I'd probably use what the U.K.'s doing in the North Sea as a

resource analog to the problem and look at what they are doing. Because they've got magnitudes more population and lot more industry than Alaska has. So I'd just offer that up as food for thought. And I think it is challenging. I don't think it's a crisis but I think it's very challenging. Thank you.

CHAIRMAN NORMAN: Thank you, Denise. And I accept that comment with the understanding you'll be getting on a plane and going back to somewhere else. But you must understand that here we're not connected into the pipeline grid and whether it's real or not, we are somewhat cut off and isolated. And we necessarily have to be looking out for ourselves. So I ask you to have that understanding of us too, that we're not plugged into some of the systems that exist with the Lower 48 states and Canada. But I do appreciate your comment in that perspective. Norm?

REPRESENTATIVE ROKEBERG: Thank you, John. Just a couple of brief points. I'm Representative Norman Rokeberg. And what I would suggest to one thing, do not allow politicians to make the decisions as to what the next source of power generation will be. I appreciate the comments about let the market make those choices. What we don't want to have is a politically motivated little Kyoto here in Alaska.

Secondly, I'd like to see unified the electrical grid here in this state. And thirdly, I would like to -- perhaps I could, this is really not directed at Harold, but this is a

statement about I think a failure of political leadership in the state to not support ANGDA as well as we should have both in the Legislature, financially and in the administration, because I don't think Alaska is prepared if, in fact, we did get an ANS gas contract, we wouldn't be prepared to meet the open season bidding if it was in 18 or 24 months.

What is the entity that's going to own the spur itself? Is it ANGDA itself, or is it going to be a private corporation, or what? We haven't even had that discussion in my understanding. So I think it's high time we did and we funded the good work that ANGDA has done.

MR. HEINZE: Hear, hear.

CHAIRMAN NORMAN: Hands? Here's one over here, Jody. While Jody's going I'm going to read one question and we can decide, that was handed to me. Anchorage's closest fault is the Castle Mountain Fault. As the study it exists within 20 miles -- or proposed South Central Alaska natural gas study shows any current pipelines exist within 20 miles of this fault. What measures are in place to secure the integrity of these pipelines in case of earthquakes associated with this fault? Harold, would you be able to respond? Harold, would you be able to respond?

MR. HEINZE: Sure. The Castle Mountain Fault is pretty well known. The eastern end of it goes up beyond Chickaloon, on up into the mountains there. The western end,

actually you can't see, but it goes under a great deal of the Matanuska Valley south of Houston by a little bit. We looked at it from several different points of view. It's identifiable. We looked at the potential frequency, potential magnitude of an earthquake, and we looked at designs.

As you come through the eastern part of the sort of Glennallen to Palmer route you are within a few miles of that fault. And in some places we actually crossed it. Our engineering contractors were able to develop a design that seemed very acceptable to cross it in those areas.

I'm not sure whether a design has been done for the western extension of that fault. It is a little more active and a little more throw on that fault. It might be a little more difficult design. But given the design of TAPS to cross one of the most major fault zones in North America, I'll put it that way, I think it's a very doable thing and it is something that I guess in trying to describe earlier the 95 percent that was easy. This is part of the five percent that's hard. And you spend some time and money on it to work. But it is very doable.

CHAIRMAN NORMAN: Thank you. Question. You, sir?

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PUBLIC COMMENT

UNIDENTIFIED VOICE: Yes. Thank you very much. Well, first of all, I came in late so some of my comments reflect I'm uninformed. I hope you'll give me a little space there. I thought Mr. Heinze said something very, very important. And if I got it down right, he said we were being distracted by the gas pipeline and that there was an overload of good ideas. Now I thought that went right to the heart of things. It's my opinion that you got scooped early. Because the process stumbled and tripped you. Your people's time and their assets are being tied up and deluded on a huge base.

So I would suggest to you that your next meeting should be to develop RFPs for world wide distribution. And those RFPs should be the sovereign gas line from Prudhoe Bay to Valdez, the other one should be the Canadian line -- which I refer to it as the Canadian line, refinery potential. And the request for a list of those who want to participate in the new avenues of Alaska. I think you need to put this RFP out there to see who's going to finance, who wants to play. Because what's happening here in my opinion is that when things begin to fall and become confusing, the burden falls back to you as a community. What's unique is that you are not only a community, you are a state and a nation, and there's a little bit of a problem of identity.

In closing I would say this. I am just staggered by

the loss of the depth and the breadth of the conversation and the content of the people that are here today. If I might stand for just a minute, Mr. Norman. When I look at the names of those people, the industries they represent and the wisdom they bring to this table as some type of avant-garde wave of leadership and thought and thinking, and to have these three days go by without some type of a DVD or audio video, to not be catalogued in some file, some archive to lend credence to testimony at a later date, to give spontaneity for new ideas, to fall back on the depth and breadth as you intertwine your community, because you are right.

You all have embarked upon the interweaving of the fabric like developed of a small nation here and you need to get on with the business. But if you fail this infrastructure there is no reason why there should not have been cameras here for these three days to be put on video for people to see across this great nation. There's absolutely no justification. So please, somebody in charge of responsibility, get out of the funds, get yourself a camera crew. You've got a city channel, you've got a university channel, you have a borough, you have the state, the gavel to gavel. There is no excuse for not having it.

And those people who bring you an RFP, they will be men enough to beswear themselves in so their testimony can be accountable so it does not hinder you in a future development

of intertwining the fabrics. And I thank you for allowing me to talk so long, which is really inappropriate for what my contribution has been. Thank you.

CHAIRMAN NORMAN: Okay. Thank you, sir, for that comment. And if to the extent that there is any fault with the structure of the proceeding, why that fault rests with me as the chairman. So I've heard your comments and we're doing the best we can.

Some have asked about follow up and there is a verbatim transcript being prepared of these entire proceedings, and with exhibits. That will be available. Also working with ISER, Mr. Peter Larsen. Peter, would you stand, please, and be recognized. Let's give Peter a round of applause. A summary trying to capture some of the ideas and issues identified here will be prepared by ISER and will be given broad distribution also.

Other questions? We still have time for a few more. Yes, sir. Where's the microphone? Tom Marshall.

MR. MARSHALL: My name is Tom Marshall. And I have been overwhelmed by the generosity of all those who have participated in this conference. Frankly, I've never seen anything like it in my 49 years here in Alaska. And if I may be so bold, I'd like one great round of applause for all who had any responsibility in putting it together.

CHAIRMAN NORMAN: Well, being an old hand, I'm

going to quit right there. I don't think I can get any better questions or comments than that. Seriously, I did promise that we'd get out of here at 5:00. We have a couple of housekeeping items and then we will definitely end before or on time. If there are any final last comments, please keep them brief. Bill Popp?

MR. POPP: Well, this isn't a comment about any of the things that we've talked about, but this is a comment to say thank you to Jody Colombie and all the other staff that have helped to keep this thing smoothly flowing out at the front desk, making sure that when we ran out of coffee they ran down the steps of the Egan Center to get a refill, and dealing with all the myriad of little details.

And as one of the people who helped put this thing together and had the privilege in helping to set the agenda I know that it would not have been a successful agenda without the staff. So I think a round of applause for the staff is well deserved.

And then, finally, I want to thank Commissioner Norman and Commissioner Seamount who is sliding around in the back there, for putting this thing together. This was their brain child and I think they did a fantastic job of putting together a very complex agenda in a very short period of time. And they should also be congratulated for putting this event together because they were the driving force behind it. So you remember

them.

CHAIRMAN NORMAN: Thank you for those comments, Bill. Jody, would you hold up your hand? Jody Colombie, Special Assistant to the Commission. Ceresa Tolley, Commissioner Assistant.

And I want to acknowledge the huge amount of support we've had from the State Department of Natural Resources. We're not part of that department. We're a separate independent agency, but the Division of Oil & Gas supplied a number of personnel here also that assisted.

Sheila Westfall, Emily Reyes, Maxine Blake. If you're here, please stand. Elizabeth Spurgeon, Peggy Brown, Brock Steller, Andi Crippen, Melissa Richey, Wanda Feela. All of them have regular work to do, and jobs, and they have broken away and donated their time here. And we do appreciate it. Let's have a round of applause for all of them.

Again, special thanks to Bill Popp, to Peter Larsen, to Will Nebesky with the Division of Oil & Gas, who has provided a lot of valuable input above and beyond the call of duty.

Also I want to say a special thanks to my co-Commissioner, Dan Seamount, who took the laboring over through these two days and kept this program moving and on time. And did it with humor and good will. Thank you, Dan, it's a pleasure working with you.

And also I want to thank our third Commissioner, Kathy

Forester, who kept the store open and did our day jobs for us so that we could be here attending to this. Can we have a round of applause for Dan and Kathy?

And since we're near closing I won't take the time to thank all of the presenters but I do know that you had the option to say no, I'm busy on something else. I also know everyone of you here has things that you could and probably should have been busy on.

And I do express appreciation on the part of I think all of the citizens of the state of Alaska in the spirit that Tom Marshall identified, I think you were generous of your time. You came here, you were forthcoming with your ideas.

The AOGCC has taken this on, not necessarily because it's directly within our area of responsibility, but primarily because it's something that needed to be done. And it may be that we will pass the baton to other agencies perhaps better suited.

Some of the things discussed here are not within our areas of expertise. We don't have any economists. We don't normally even think in those terms. We do have a good deal of geologic and engineering expertise under our roof, but then we generally think subsurface. But again, a lot of the ideas here are out on the far periphery, but our feeling was that someone needed to do it. The governor asked us to do it and so we have tried to do our best to present this to you.

These proceedings will be preserved in a transcript. There will be a summary. And then we will try to keep an eye on this issue and act as a coordinator until someone, some agency better suited than we are either takes the ball or until industry, which ultimately is going to have to solve this issue, is able to work through it. But we will be there as a resource to try to help the industry as well as the three municipalities.

So with that, thanking everyone, we're finished 15 minutes ahead of time and I'll declare these proceedings closed. Thank you.

(Off record - 4:45 p.m.)

(END OF PROCEEDINGS)

C E R T I F I C A T E

UNITED STATES OF AMERICA)
)ss.
STATE OF ALASKA)

I, Rebecca Nelms, Notary Public in and for the State of Alaska, residing at Anchorage, Alaska, and Reporter for R & R Court Reporters, Inc., do hereby certify:

THAT the annexed and foregoing SOUTH CENTRAL ALASKA ENERGY FORUM held on September 20th and 21st, 2006 was taken by Suzan K. Olson, commencing at the hour of 8:00 o'clock a.m, at the Egan Convention Center, Anchorage, Alaska;

THAT this Public Forum, as heretofore annexed, is a true and correct transcription of the proceedings taken by Suzan Olson and transcribed by Suzan Olson, Lynn Hall, Meredith Downing, Wanda Ventres and myself;

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my seal this 10th day of October, 2006.

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Notary Public in and for Alaska

My Commission Expires:10/10/06