

ALASKA STATE LEGISLATURE
HOUSE SPECIAL COMMITTEE ON OIL AND GAS

February 15, 2005

5:10 p.m.

MEMBERS PRESENT

Representative Vic Kohring, Chair
Representative Ralph Samuels, Vice Chair
Representative Nancy Dahlstrom
Representative Norman Rokeberg
Representative Berta Gardner

MEMBERS ABSENT

Representative Lesil McGuire
Representative Beth Kerttula

COMMITTEE CALENDAR

SENATE JOINT RESOLUTION NO. 5
Urging the United States Congress to reauthorize the Methane Hydrate Research and Development Act.

- MOVED HCS SJR 5(O&G) OUT OF COMMITTEE

PREVIOUS COMMITTEE ACTION

No previous action to record.

WITNESS REGISTER

JOE BALASH, Staff
to Senator Gene Therriault
Alaska State Legislature
Juneau, Alaska

POSITION STATEMENT: Presented SJR 5 on behalf of Senator Therriault, bill sponsor.

MARK MYERS, Director
Division of Oil and Gas
Alaska Department of Natural Resources

POSITION STATEMENT: Testified in support HB 71 and answered questions regarding gas hydrate research.

ACTION NARRATIVE

CHAIR VIC KOHRING called the House Special Committee on Oil and Gas meeting to order at [5:10:33 PM](#). Representatives Dahlstrom, Gardner, Kohring, Rokeberg, and Samuels were present at the call to order.

SJR 5 - REAUTHORIZE METHANE HYDRATE RESEARCH ACT

[5:11:17 PM](#)

CHAIR KOHRING announced that the only order of business would be SENATE JOINT RESOLUTION NO. 5, "Urging the United States Congress to reauthorize the Methane Hydrate Research and Development Act."

JOE BALASH, Staff to Senator Gene Therriault, Alaska State Legislature, testified on behalf of Senator Therriault, sponsor of SJR 5. He explained that the resolution urges the U.S. Congress to reauthorize the Methane Hydrate Research and Development Act for another five years, and also asks for appropriations of \$70 million over that time period. He stated that the potential additional reserves present in the form of gas hydrates is important to the [gas] pipeline project. He said, "The sizing of the pipe, access points into the pipe as well as out of the pipe, financing costs, and ultimately the tariffs could all be positively impacted by the determination of the commercial viability of additional reserves in the form of these gas hydrates up on the [North Slope]."

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MR. BALASH presented a simple description of gas hydrates:

Methane that's captured in an ice lattice that is present in cold areas, or areas ... that are under tremendous pressure. And once freed from that ice lattice, [the molecules] expand to 180 times their size, in their crystallized form. ... The industry is well aware of the presence of the hydrates on the slope; we know they exist. Whether or not we can put them into commercial production or not is what needs to be researched; that's what the original Methane Hydrate Research Development Act of 2000 sought to find. There's a lot of work that's been done, particularly in the lab, in computer models and simulations that are now ready to be taken to the next step: field-testing and hopefully a pilot project.

5:13:38 PM

REPRESENTATIVE DAHLSTROM asked if [methane hydrate] is the thing that she has heard referred to as the "popsicle".

MR. BALASH had not heard of this term. He clarified that his understanding is that in the North Slope reservoirs, the crude oil is at the bottom, and above that is the gas cap. Above the gas cap is where the hydrates exist, close to the permafrost, he explained. He said that when companies drill on the North Slope, they have encountered hydrates and have developed the techniques of putting in casings right away to make sure that they don't experience any technical hazards such as blowouts.

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CHAIR KOHRING asked if this resolution is the first one that the State of Alaska has sent to Congress to urge them to authorize something of this nature. He asked, "Did we not do one in 2000?"

MR. BALASH answered that he is not familiar with one.

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CHAIR KOHRING commented that research was conducted for five years as a result of the original authorization in 2000. He asked what the research results were.

MR. BALASH pointed out that in the committee packet, there was a letter from Tim Collett, U.S. Geological Survey, to Bonnie Robson, Consultant to Legislative Budget and Audit Committee. The letter provided an update on the gas hydrate research that had been conducted on the North Slope and in the Arctic areas. He said, "They've developed some techniques for looking at seismic data to come up with estimates on how much gas hydrate is present in ... both the onshore portion as well as the offshore portion of the North Slope and the area around there. And they've done a little bit to try and define the locations a little bit better."

MR. BALASH, in response to Chair Kohring, responded that the original authorization was substantially less than \$70 million; he guessed that it was \$50 million. He said that a lot of modeling has been done on ways to release the methane from the hydrate form to the gaseous state. He commented that there are "hundreds if not tens of thousands of tcf [trillion cubic feet]

of this gas hydrate present on the slope, but how much of it can be recovered [is] obviously an open question at this point. They can't prove that any of it is, but they suspect that very much of it is [recoverable]."

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MR. BALASH stated that there is an estimated 590 tcf of gas hydrates onshore in the Arctic Slope region. In comparison, he remarked that the proposed gas pipeline project is dependent upon 35 tcf of known reserves on the North Slope, in the Prudhoe Bay and Point Thompson units. Within the stability zone of the Beaufort Sea and the Chukchi Sea, he commented, the offshore reserves are estimated at 32,000 tcf. He said, "We're not talking about a pipeline anymore; we're talking about pipelines."

CHAIR KOHRING noted that Representative Samuels traveled to Congress recently to testify before the U.S. Senate's Energy Committee, asking that this act be reauthorized.

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REPRESENTATIVE SAMUELS stated:

There's interest not just from Alaska, but because of the formation of the hydrates, there's also interest in the Gulf of Mexico. One of the prime sponsors was Senator Daniel Akaka from Hawaii, actually, because there's thinking that there might be potential there. And I believe ... most of the work that [has] been done until now has been mostly academic and ... modeling, and from here on out, you would like to get into the field and see what we can actually do. ... When we went to Washington [D.C.] to try to get support for this research ..., the point wasn't to get money to be spent within the state, like we normally get for things. We just wanted the research to be done because we know how many hydrates we've got. It just so happens that we probably also have the easiest place to do the research, so it's a bit of a side benefit. Because of the massive amounts of [methane hydrates] we have up there, I think it's obviously important for the state, but it's also important for the country.

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MARK MYERS, Director, Division of Oil and Gas, Alaska Department of Natural Resources (DNR), in response to Chair Kohring, replied that he thinks the legislature should support this resolution. He said:

What's important here is to ... put it in perspective, to go back and look at the original methane hydrate act of 2000. It was a five-year authorization [for] ... \$45.7 million. And the primary goal there was to understand the hydrates and ... get the hydrates up to the point that we would understand their potential commerciality, but it basically fell short of the operational testing of the hydrates. The money was spent not only in Alaska but [also] in other areas like the Gulf of Mexico. In Alaska there were two major efforts undergone, ... sponsored through DOE [Department of Energy], and they were joint industry/government type proposals. One had [Anadarko Petroleum Corporation] and {Maurer Technology, Inc.}; ... they drilled south of Kuparuk, off the arctic platform. So it not only drilled for hydrates but it also tested out the technology of the arctic platform.

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MR. MYERS continued:

The second proposal was primarily [BP Exploration (Alaska) Inc.] with Arctic Slope Energy Services ... with the USGS [U.S. Geological Survey] also ..., and they looked at the hydrate potential where we knew it existed in the Milne Point field area. And there they actually very carefully modeled the hydrates based on the 3-D seismic that was available to them through BP, particularly shallow parts of the survey. So they had high quality seismic data in which they could map out the actual physical locations of the hydrates. That was combined with well penetrations so you actually had penetrations through the hydrates to quantify the ... seismic attributes. And what they found using the 3-D seismic wasn't a surprise to folks in industry because we've had to map hydrates for years to worry about them as a geohazard as you drilled through them [so] that you didn't have an uncontrolled release of the gas. So one of the things you had to prove to the Oil and Gas Conservation Commission [was] that ... if

they were likely to be present ... what mitigation measures you would take. And as [Mr. Balash] mentioned, you generally case off the wells, the hydrate zones, the active gas zones to prevent the gas from flowing into the well bore when you're drilling for a deeper oil horizon. So we have lots of well penetrations in the Milne Point field, Prudhoe Bay field, [and] Kuparuk field, where we knew there [was a] presence of hydrates. The 3-D seismic allowed us to calibrate the actual physical location of the hydrates by not only just locating the structural elements [and] controlling their distribution, but also actually mapping out the particular attributes of the hydrates. As important is the free gas that exists underneath the hydrates.

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MR. MYERS continued:

The DOE money in Alaska was spent on detailed mapping of the hydrates [using] 3-D seismic, a lot of sophisticated modeling of that. And then using well data to recalibrate and look at the reservoir the hydrates existed in. Then they went to the next step, and that was detailed reservoir simulations. They took very complex computer models, inputted all this data, and looked at what a typical test rate would be from the hydrates. And particularly in the areas where they had the ... free gas underneath the frozen hydrate, ... they got very positive results from the modeling: up to 50 million cubic feet [mcf] per day out of wells, sustained rates ... above five to ten million a day out of a single well. And high recovery rates: 60 percent of the hydrates in an individual fault block recovered. So the modeling suggested very economic rates of flow and huge volumes of recovery. ... The modeling showed about 100 trillion cubic feet of hydrate in place just underneath our existing infrastructure alone, [and] ... potentially up to 60 trillion cubic feet of additional gas reserves, in addition to the 24 tcf in the conventional Prudhoe Bay reservoir, could be present and could be commercially produced. Now that was incredibly encouraging because that means we have a 30 plus year of gas supply for the pipeline, assuming it's commercial. And that's sort of where the studies ended in Alaska.

5:27:45 PM

MR. MYERS continued:

Additional work was also done in the area around Barrow, where we have the Walakpa gas fields, and [there are] indications that hydrates exist there, so hydrates also are probably used now, and probably will be in the future a source of local gas for communities like Barrow. So we had a real interest in some study done by BLM [Bureau of Land Management] and others in the area of the Walakpa gas field there near Barrow. ... A combination of those two places is sort of where the research in Alaska ended here in year five. Additional work was done in the Gulf of Mexico [and] USGS did work in the Mackenzie delta. ... We got to the tantalizing opinion by the experts ... that we're looking at something that could be highly commercial and significant in all aspects with respect to a commercial gas line. But we never actually tested it. So we have the geologists and the geophysicists and the computer modeling saying it should work, but we never got the holes drilled and the actual long term production testing. So the "prove it" stage is where we're at now, and that's actually the more expensive stage when you think about [it]. ... Doing the analysis is one thing; physically drilling the wells and long term testing the wells is the more expensive part of it. ... This next five years was designed at \$70 million over the five-year period [to be for] ... hard-core testing. [We're] assuming an operator from the fields like BP or someone else ... would actually drill the wells and actually do the testing, and then would be paid for it out of the grant to get the research results. And then there would be government-supported work, University of Alaska-supported work, and some DNR-supported work along that same line. But the goal again is this long term, hard-core testing to verify the models, which again is critical to actually prove that the models are right and that these reserves could be commercialized ... in the time frame that we would hope they could be to add value to a gas line project.

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MR. MYERS continued:

We looked at ... multiple types of tests. The first test is a relatively simple test where ... you have a free gas [lake] underneath the hydrates and you just produce the free gas, lowering the pressure. Hydrates form under certain pressure/temperature regimes; as you increase temperature or lower pressure, either one will bring the hydrates out of solution. So the first type of testing would be an actual depressurizing [of] the hydrates using conventional or horizontal well technology, pretty ... common technology used today. And then we would have a long-term test to see if you could sustain the rates that the model suggests. The next would be tests where you didn't have a free gas [lake], where you'd have to use a different ... mechanism to get the hydrates out.

MR. MYERS continued:

There are two other mechanisms proposed. One is you actually heat the reservoir. By heating the reservoir, again you've changed the pressure/temperature regime [and] hydrates come out of solution. And that happens naturally when you drill an oil well through the zone. [The drilling bit] is hot on the surrounding permafrost and sediment, and what happens then is some of the hydrates get released. And that's why again you put the casing around to cool the zone and prevent it from flowing into the well bore. ... You could circulate glycol or some other mechanism. Thermal methods for recovering hydrates need to be tested [and] demonstrated [for] long-term commercial viability. The third method that's been suggested is a chemical replacement. ... Carbon dioxide [CO₂] could in fact replace methane molecules one for one in the crystalline lattice. So you've got a lot with the gas line and major gas sale. You've got a lot of CO₂ at Prudhoe Bay; about 12 percent of the gas is CO₂. You could take that CO₂ and sequester it in the hydrate matrix and pull out methane. Now in a lab that works fairly well, but again we haven't actually tested in the well bore. So the \$70 million over the long term would be [used] to do all three types of long term testing, ... [which is] more expensive than just doing theoretical modeling or geophysical modeling.

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MR. MYERS continued:

Additional work would be done in areas like NPRA [National Petroleum Reserve, Alaska], where Native communities ... or village communities could be served by this as a local energy source. And in the longer aspect, maybe some commerciality [would develop] in NPRA or other areas where we know hydrates exist. ... The numbers onshore on the hydrates that have been mapped to date ... are over 500 tcf. So [it's a] huge potential resource that could ultimately deliver to the United States a lot more energy than we have even in all of our conventional reserves combined. ... So \$70 million to demonstrate and prove that the gas hydrates are viable in Alaska is huge leverage to the country in terms of our gas supply. And that's why we think it's appropriate again that the Senate and Congress fund this proposal.

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CHAIR KOHRING asked how the estimated gas potential on the North Slope relates to the current consumption in the U.S.

MR. MYERS replied that [by the time the gas pipeline is proposed to be in operation] the U.S. consumption is expected to be between 70-85 tcf/year. Currently he said that it's around 60 tcf/year.

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CHAIR KOHRING commented that the oil and gas industry stands to benefit from this and wondered why the industry doesn't pay for this. He remarked that he would like to see more industry involvement and have them pay for part of this since they are going to benefit from this as well.

MR. BALASH replied:

I'm not sure ... whether or not BP is contributing any cash to the research project but they certainly have made their information available. I think they've been involved in their 3-D seismic technology, allowing their resources and assets to be used in the

research. ... Generally speaking, ... private industry, private capital isn't necessarily going to go out and invest the dollars that we're talking about in this kind of research until there's an actual need for it. There's already 35 trillion cubic feet of gas on the North Slope in conventionally known reserves that they're trying to get to market. There's not a market incentive for them to go and validate this academic [data].

CHAIR KOHRING remarked, "Maybe in the future we could sell them the data too. When they're ready to take the issue seriously, we have the data we invested \$120 million in; maybe we can sell them some of that and recoup some of our investment."

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CHAIR KOHRING asked Mr. Myers to explain the difference between the gas hydrates in Alaska and those in the Gulf of Mexico.

MR. MYERS responded:

There's a couple of differences. First of all ours are onshore. ... The hydrates form the crystalline lattice under a certain pressure/temperature relationship, and if you have a higher temperature, then it requires greater pressure. Lower temperature, less pressure. So it's the combination of temperature and pressure that work together. So in Alaska, because of our cold temperatures, that pressure gradient occurs at very shallow depths, and in fact it occurs onshore in the permafrost. And it occurs that way in Russia and in the Mackenzie delta as well, for example. So in the Gulf of Mexico ... there are hydrates but they're usually in deep water, so the economics of production will never be as good as they are in Alaska. The second component is [that] ... the hydrates we have in the Prudhoe Bay area ... are thermogenic gas, which means they are created in the same temperature and pressure that generally oil is, and they're driven off conventional source rocks. Other types of methane are typically biogenic, which means they're created by organisms that are basically digesting material and they produce methane as a byproduct. So microorganisms will actually produce methane at the nearest sediment/water interface. So here we have conventional gas that's migrating up

[depth]; it's being produced at deeper depths in the same structures that are basically generating oil and gas for the conventional oil and gas fields in the Prudhoe area. And that gas is physically up [depth] and it finds these fault blocks where it's structurally trapped. So it's not diffuse; it's in very thick formations, and it's in a conventional fault block. And underneath the conventional hydrates, where the right temperature and pressure exist, is a zone of higher pressure where the gas actually exists in slightly warmer temperatures, where the exact gas exists as in the gaseous state. So we have this hydrate underlain by free gas. And at least in the modeling, those are going to be the most economic hydrates because again you don't have to use exotic technology; you don't have to heat it or chemically replace. You can simply [depressurize] the hydrates, which pressurizes the free gas underneath, using very standard technology, and then the hydrates will naturally come out of solution. Along with that the gas will come up by itself and the water won't come out with it. So you produce basically water-free methane into an already-producing gas zone. So the commerciality of that is going to be much better than using the exotic technologies, and the rates suggested by the modeling are much higher.

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MR. MYERS continued:

So we've got a combination then of onshore [gas that is] underneath existing infrastructure. When we have a gasline, we'll have a market for that gas. We'll have pipelines connecting it up, and again we have this thermogenic gas ... that can be produced [via] ... conventional technology. That gives us a huge commercial leg up in areas like the deep water Gulf of Mexico, where you'd be producing off in very deep-water platforms. Can it be done commercially at some point? Sure, but the costs of those development wells is going to be extremely high. We're talking about really post hole wells ... that will be 3000 feet at depth, or shallower. So again we have economic advantages ... of having infrastructure, and we're onshore. All that, I think, leads to Alaska [as well

as places like Siberia] as being the leading areas where you'll see this hydrate developed first.

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CHAIR KOHRING asked if there is a potential for gas hydrates in Cook Inlet, and if so, perhaps the resolution should be modified to encourage Congress to explore in Cook Inlet as well.

MR. MYERS reiterated that the hydrates exist due to the combination of the temperature and pressure. There are warmer temperatures in Cook Inlet, he stated, and he is not aware of any naturally occurring hydrates in that area. He remarked that there is a lot of conventional biogenic gas and very little thermogenic gas [in Cook Inlet]. He commented that perhaps there are some hydrates in the Aleutian Trench, but that's a long way from the Cook Inlet infrastructure. He stated that on the North Slope there is a hydrate stability zone that goes down into the North Slope foothills and far offshore, but it generally doesn't occur south of the Brooks Range.

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REPRESENTATIVE SAMUELS asked if [the researchers] could use current well sites to do some of the research since this project is for research purposes.

MR. MYERS answered that there are advantages to this, since there are many old, closed off wells that penetrated the hydrate zone. He said:

There's lots of ability to use the existing wells and infrastructures, and the gravel pads, for instance, are all laid. ... The use of the existing infrastructure dramatically decreases the cost and the efforts, and would allow long term testing and could certainly be done in wells that ... are already existing and are no longer useful in the deeper depths by just simply plugging them back. And logically we'll see some of that work when we get a major gas sale anyway; there'll be modification of oil wells to gas wells.... The companies will have to be able to use the gas at the time of long-term testing in some way in the field. So there are win-wins, particularly if they're short, as in some of the fields like Milne Point, generally short of natural gas to use for running in operations. ... In the long term, testing

the gas could actually be used constructively in the field to run power plants or to ... use as fuel gas for compressors....

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REPRESENTATIVE SAMUELS commented:

Other than the potential of the [methane] ... melting into the free gas as you release the pressure, if there is no gas cap, there's still obviously a lot of hydrates. That technology would be pretty far off into the future. ... Even with the research you're not talking about the development of that in the next couple of years, but with the cap, and releasing the pressure, you could possibly do some of that in the short term. Would that be a true statement?

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MR. MYERS answered affirmatively and stated:

Using conventional technology, proving out the long term testing and then by lowering the pressure, if you're actually getting a significant contribution from the hydrates - that would be testable, and you can monitor that pretty accurately. The other techniques definitely involve putting a lot of energy into the well or using chemical substitution, [and] ought to be tested, but logically, from a commercial standpoint, we're looking at a North Slope gasline for example, and you're trying to monetize that gas in the long term. You're going to take, basically, your Prudhoe Bay gas and some of the solution gas from other fields like Milne Point ... and you're going to start producing that gas off first. And then as you have additional space in the line, you're going to backfill it, and you're going to backfill it first with the most commercial, high rate gas and then go to ... the other gas later. At least the modeling would suggest ... [that] the high rate's going to come from the combination of free gas and hydrates. So I think it's incremental. You certainly want to test it and develop the technology, because there's a valuable resource there, but ... the high present value would be in that first technique. And so we would recommend the proposed funding would start out very early on

with that initial test of the pressure and then follow on with testing the later technologies in the off years, the years three, four, and five.

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REPRESENTATIVE ROKEBERG asked:

What would be the status of a lease-hold interest that would be under production now that may contain the methane hydrates, if it would be shut in for pre-gas or oil production now, and it still contains some potential uses in hydrate development in the future? What would be the status of the lease and how would that be handled by your department?

MR. MYERS replied that as long as the lease is producing and reasonable attempts have been made to produce all the resource, there's just no conflict and the lease is held by production of the unit and the unit work commitments. He said that DNR takes a rational approach on this: if a company is producing oil or conventional gas and there's no capacity to sell that additional hydrate resource, the company will keep the lease. He remarked that he didn't think there was any jeopardy to the existing leaseholder.

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REPRESENTATIVE ROKEBERG clarified:

I'm concerned about the situation where we could have ... a conventional petroleum well being shut in, and then getting in the situation you described where there would be a lack of capacity in a gas line and then there's even the technology to produce the hydrates, then you'd have gas in place. What would be the legal status of the lease then if you couldn't produce it?

MR. MYERS responded:

It would be determined by the unit plan of development. ... And there are two other caveats; one is physical and economic waste. And obviously we're going to want to maximize the production from the lease in the most efficient way, both from physical and economic parameters. ... If the hydrates are

waiting in line for capacity in the line, it's not going to jeopardize anyone's lease. ... There are a lot of old gas fields that are being held for a long period of time because of that issue. I think the operator has to do a diligent plan of development, but it's an orderly plan of development, so ... I can't imagine it jeopardizing any leaseholders. Now if the leaseholder has the opportunity to monetize it, and it is [demonstrably] commercial, and there is market for it, and pipeline capacity for it ... DNR typically will challenge that plan of development.

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CHAIR KOHRING, in response to Representative Rokeberg, remarked that perhaps the topic [of the obligations of the lessee to the lessor] could be addressed in the House Resource Standing Committee.

MR. BALASH pointed out that there was a change that the sponsor wanted the committee to entertain. He turned the committee's attention to page 3, line 1, and explained, "At the time the resolution was introduced, and even when it passed the Senate, Samuel Bodman had not yet been confirmed by the United States Senate. He has now, and has been sworn in. So the word 'designee' can be removed."

[5:50:16 PM](#)

REPRESENTATIVE DAHLSTROM [made a motion] to amend SJR 5 by deleting "designee" from page 3, line 1. There being no objection, it was so amended.

REPRESENTATIVE SAMUELS moved to report SJR 5, as amended, from the committee with individual recommendations and the accompanying zero fiscal note. There being no objection, HCS SJR 5(O&G) was reported from the House Special Committee on Oil and Gas.

ADJOURNMENT

There being no further business before the committee, the House Special Committee on Oil and Gas meeting was adjourned at [5:52:02 PM](#).