NORTH DAKOTA LEGISLATIVE MANAGEMENT

Minutes of the

TAXATION COMMITTEE

Wednesday, April 27, 2016
Roughrider Room, State Capitol
Bismarck, North Dakota

Senator Jessica Unruh, Chairman, called the meeting to order at 9:00 a.m.

Members present: Senators Jessica Unruh, Brad Bekkedahl, Dwight Cook, Jim Dotzenrod, David Hogue, Lonnie J. Laffen, Connie Triplett; Representatives Jason Dockter, Glen Froseth, Patrick R. Hatlestad, Craig Headland, Jerry Kelsh, Alisa Mitskog

Members absent: Representatives Wesley R. Belter, Tom Kading, Jim Kasper, Vicky Steiner, and Marie Strinden

Others present: See Appendix A for additional persons present.

It was moved by Representative Hatlestad, seconded by Senator Triplett, and carried on a voice vote that the minutes of the February 9, 2016, meeting be approved as distributed.

ENHANCED OIL AND GAS RECOVERY STUDY

IHS Energy

Chairman Unruh said the Legislative Council staff distributed a handout (Appendix B) containing the last two monthly progress reports submitted by IHS Energy in regard to the committee's study of scientific and economic information pertaining to oil and gas recovery and enhanced oil recovery techniques.

Chairman Unruh called on Ms. Irena Agalliu, Managing Director, Mr. Curtis Smith, Director of Consulting, and Mr. Mohammad Tavallali, Principal Reservoir Engineer, IHS Energy, for a presentation of IHS Energy's interim report (Appendix C) on the economic impact of carbon dioxide (CO^2) enhanced oil recovery in North Dakota. Ms. Agalliu said the interim report focuses on the technical analysis and upstream economics related to the study. She said information pertaining to indirect and induced impacts of CO^2 enhanced oil recovery will be included in IHS Energy's final report.

Mr. Smith said the presentation is divided into four parts consisting of CO^2 enhanced oil recovery in unconventional reservoirs, CO^2 enhanced oil recovery in conventional fields, the economic model assumptions that were applied to each, and an analysis of the upstream economics. He said the use of CO^2 enhanced oil recovery in unconventional reservoirs such as the Bakken and Three Forks Formations is only at the modeling and laboratory stage and is just beginning to reach the pilot stage. He said the use of enhanced oil recovery in unconventional fields is an attractive prospect due to the large amount of original oil in place. He said it is also promising due to the high-pressure environment found in these reservoirs. He said only a small pilot project has occurred, but the preliminary modeling is encouraging. He said the Bakken Formation is expected to reach peak production of approximately 1.4 million barrels of oil per day in 2026. He said the hope is that by 2026, the technology related to carbon capture and injection will have evolved and additional infrastructure will be in place.

In response to a question from Chairman Unruh, Mr. Smith said he would have a conversation with representatives from the Energy and Environmental Research Center (EERC) to ensure IHS Energy is aware of all pilot programs in North Dakota and incorporate all relevant data into the model.

Mr. Smith reviewed the various uncertainties IHS Energy accounted for when formulating the model and how those uncertainties were addressed. He said a notable consideration is whether the fractures created by hydraulic fracturing will impact the flow of CO^2 through a reservoir allowing it to flow too freely from one well bore to another.

Mr. Smith said IHS Energy input a 5 percent recovery factor into the model for wells with one-half-mile injector well spacing and a 7.5 percent recovery factor for wells with one-quarter-mile injector well spacing. He said the production forecast associated with wells having one-quarter-mile spacing was an increase of 300,000 barrels of oil over a 10-year period. He said the model accounted for two scenarios. He said case one operated under the assumption that existing wells could be converted into injector wells and case two operated under the assumption that new injector wells would have to be drilled.

In response to a question from Senator Bekkedahl, Mr. Smith said the model assumed a cost of $250,000 to $300,000 to convert an existing production well into an injector well. Mr. Smith said the cost of drilling an entirely new injector well was estimated at roughly $5.6 million to $6.6 million.

Mr. Smith said up to 2.2 billion cubic feet (BCF) of CO^2 could be needed by the time the state reaches full production capacity. He said the model assumes an additional transportation cost of $2 per thousand cubic feet (MCF) for any CO^2 that would need to be shipped in from sources outside of this state. He said the cost of CO^2 per barrel of oil produced would be approximately $45 per barrel under case two.

In response to a question from Representative Hatlestad, Ms. Agalliu said the break-even price for higher producing wells would be reached when oil prices reach $89 to $90 per barrel. Ms. Agalliu said the break-even price for lower producing wells would be reached when oil prices climb well above $100 per barrel.

In response to a question from Representative Froseth, Mr. Smith said the shale found in the Bakken Formation is unique on a global scale. Mr. Smith said the shale in the Bakken Formation is very different from the shale found in the Eagle Ford Formation and is somewhat different from the shale found in the Permian Basin.

In response to a question from Representative Headland, Mr. Smith said roughly 133 million cubic feet of CO^2 is being produced by the Dakota Gasification Company for use in enhanced oil recovery projects in Canada. Mr. Smith said if all the CO^2 produced by the Dakota Gasification Company was redirected for use in an enhanced oil recovery operation in this state, it would still only account for about one-tenth of the CO^2 needed for a full-scale commercialization of the Bakken Formation.

In response to a question from Representative Froseth, Mr. Smith said the need for CO^2 capture is seen in many states, but the technology associated with CO^2 capture is still quite expensive. Mr. Smith said IHS Energy reviewed three plants undergoing a CO^2 capture process. He said there is a project in Texas and Saskatchewan, but the project in Saskatchewan has encountered very high capital costs. He said the plant in Saskatchewan is paying $5 per MCF for the conversion technology, but is receiving only $1.50 per MCF for the produced CO^2 so consumers are picking up the tab for those additional costs. He said many projects funded by the United States Department of Energy in the past have been canceled due to cost overruns and other adverse factors. He said new technology is required to reduce the cost of CO^2 capture.

Mr. Tavallali reviewed IHS Energy's findings regarding the reservoir engineering portion of the study and discussed the recovery factors associated with each stage of recovery. He said IHS Energy reviewed 800 fields during the course of the study to see which fields were best suited for tertiary recovery. He said a reservoir simulation was conducted using certain inputs for the production portion of the analysis. He said CO^2 miscible and hydrocarbon immiscible and miscible mechanism are the most successful processes for enhanced oil recovery and recommended the use of CO^2 enhanced oil recovery due to the additional benefit provided to the environment as a result of using CO^2. He said 126 of the 800 fields reviewed passed the initial screening process and 49 of the 126 fields passed the second screening process. He said 18 of the remaining 49 fields were selected for simulation as those fields had undergone successful water floods in the past. He said the Beaver Lodge-Devonian Unit appeared to be a good candidate for CO^2 injection. He said the model assumed 120 acre spacing units and the placement of 110 injectors to develop the entire field. He said the resulting recovery factor for Beaver Lodge-Devonian Unit was roughly 17 percent of original oil in place. He said it would take 2 to 4 years of injecting CO^2 before any incremental oil would be recovered from a well.

Mr. Smith reviewed some of the assumptions applied when creating the model and said nearly a billion barrels of oil could be recovered from the 18 fields that passed IHS Energy's screening process. He said the modeling took into account wells that would need to be worked over and new wells that would need to be drilled. He said cost factors that were considered included the amount of CO^2 required, the price of CO^2, any related transportation costs, pipeline and gathering costs, the costs of transporting recovered oil to market, and the cost of any necessary surface facilities such as compression and separator stations. He said the positive cashflow side of the model represents the oil and gas that would be recovered from a well. He said converting production wells to injection wells would be much less expensive than drilling entirely new injection wells. He reviewed available sources of CO^2 and said the model assumed an additional $2 per MCF for any CO^2 that would need to be transported in from outside of the state.

In response to a question from Representative Hatlestad, Mr. Smith said the model assumed a CO^2 injection period of 2 years for conventional fields and 4 years for the Bakken Formation before any additional oil would be produced.

Ms. Agalliu reviewed the assumptions applied to the model and the results of the upstream economics. She said all costs, including the amount oil companies pay in federal taxes, were accounted for in the model because operators will take all costs into consideration when determining whether to commence a project. She said the 10-year production tax exemption for tertiary recovery projects was factored into the model as were other available production tax incentives. She said there was not an example of the tax treatment this state would apply to enhanced oil recovery costs so IHS Energy assumed those costs would be treated in the same manner they are handled in Texas for purposes of conducting an economic analysis. She said in Texas enhanced oil recovery costs are treated as a deductible expense for purposes of the severance tax because enhanced oil recovery is not viewed as part of the primary recovery process. She said she welcomed any suggestions from the committee regarding the treatment of enhanced oil recovery costs.

Ms. Agalliu said this state does not impose an ad valorem tax on production but discussions with the Tax Department indicated that an ad valorem tax may be levied on separation facilities so this expense was factored into the model. She said an 18 percent royalty rate was also factored into the model for leases. She said based on these assumptions, IHS Energy calculated the price per barrel of oil that would allow projects to break even in relation to costs under this state's current taxation structure. She said a break-even price has been specified for each case and then further adjusted to reflect the changes to that price as additional fiscal measures are applied to incentivize activity. She reviewed the break-even prices for various counties for case one, in which production wells could be converted into injector wells, and for case two, in which new injector wells would need to be drilled. She said under case one, an additional 590 million barrels of oil would be added to primary production amounts under the base-case scenario. She said under the high-case scenario, an additional 632 million barrels of oil would be added to primary production amounts. She said the base-case scenario is expected to yield $5.8 billion in state revenues over the next 20 years and the high-case scenario is expected to yield $7.5 billion in state revenues over the same period. She said eliminating extraction and production taxes in case one would not have a significant benefit in terms of increased production, but would significantly reduce tax revenues. She said Williams County has the most potential for revenue from CO^2 enhanced oil recovery under case one.

Ms. Agalliu said under case two, an additional 199 million barrels of oil would be added to primary production amounts under the base-case scenario. She said under the high-case scenario, an additional 385 million barrels of oil would be added to primary production amounts. She said the base-case scenario is expected to yield $1.3 billion in state revenues over the next 20 years and the high-case scenario is expected to yield $4.2 billion in state revenues over the same period. She said eliminating production taxes in case two would have a slight benefit in terms of increased production, but would significantly reduce tax revenues. She said Williams County has the most potential for revenue from CO^2 enhanced oil recovery under case two.

Ms. Agalliu said IHS Energy encountered several challenges regarding the economics of enhanced oil recovery in conventional fields. She said many of the state's conventional fields are quite old and not all production wells could be converted into injection wells. She said 80-acre well spacing, as opposed to 120-acre well spacing, was used for conventional fields. She said under these assumptions, only five fields are expected to yield the 10 percent rate of return required to development to commence. She said conventional fields would yield much less production than the Bakken Formation. She said enhanced oil recovery in conventional fields is expected to produce an additional 19 million barrels of oil in the high-case scenario and an additional 39 million barrels of oil in the low-case scenario. She said the low-case scenario is expected to yield $105 million in state revenues over the next 20 years and the high-case scenario is expected to yield $395 million in state revenues over the same period. She said eliminating production taxes would only have a marginal effect on production, but would greatly reduce tax revenues. She said Williams County would likely see the most activity under the low-case scenario. She said significant revenues from CO^2 enhanced oil recovery would likely be seen in the mid to late 2020s as technology related to CO^2 capture, transport, and enhanced oil recovery improve.

Ms. Agalliu said IHS Energy's initial recommendations would be for the state to encourage research and development activities to determine the technological and commercial feasibility of CO^2 enhanced oil recovery, especially in the Bakken Formation. She said funding from the state or federal government to run more pilot projects in the Bakken Formation may encourage companies to invest and form joint public/private partnerships. She said incentives might also be required to incentivize the development of CO^2 capture technology. She said unless companies are certain that incentives or other programs will be in place to encourage the capture of CO^2 from power plants, it is more likely that companies will elect to use cap and trade to address emissions reductions under the federal Clean Power Plan. She said a state policy encouraging the capture of CO^2 emissions would also have the added benefit of improving the environment. She said the study was limited to production and extraction taxes for incentives, but if the committee would like IHS Energy to take other tax levies into consideration any additional incentives could be accounted for in the final report.

In response to a question from Chairman Unruh regarding the potential for incentivizing the development of CO^2 sources within the state, Ms. Agalliu said if the state is asking power plants to make these large investments, the state might consider offering income tax reductions to encourage power plants to engage in these types of investment decisions.

Mr. Smith said in looking back at some of the projects that have been funded over the last several years, the majority of those projects have been funded by United States Department of Energy grants. He said the amount that is funded is generally 20 percent of the capital expenditures related to a project. He said 20 percent seems to be the threshold amount of funding required to get companies interested in pursing these types of activities. He said this level of funding could be provided in the form of a tax credit or some other type of direct grant program.

Ms. Agalliu said the only challenge that could persist even if plants received the necessary funding are the high rates of cost overruns. She said cost overruns are one of the main reasons these types of projects are suspended.

In response to a question from Senator Bekkedahl, Ms. Agalliu said the break-even prices previously quoted are only in relation to incremental production that is above and beyond primary production amounts.

Senator Laffen said based on the information received today, it almost seems as though it would be easier to fund research than try to adjust tax policy considering all of the unknown factors that would impact whether enhanced oil recovery will be successful in this state. He said a determination of whether enhanced oil recovery would be possible may need to come before changes to the tax code. He asked if the legislature could simply fund a pilot project, rather than arbitrarily selecting a tax policy that might or might not make enhanced oil recovery work. In response, Mr. Smith said pilot projects could be structured in a number of ways. Mr. Smith said in his opinion, funding a pilot program for at least the next 2 to 3 years should be a priority to determine proof of concept and narrow the current range of uncertainties.

Chairman Unruh asked if holding off on providing any incentives for the next 2 to 3 years would disincentivize companies looking at investing in new technologies and whether it would result in a slowdown in the development of new technologies. In response, Mr. Smith said operators will certainly take a state's tax structure into account when making these large types of investments. Ms. Agalliu said tax incentives send a message to industry that the state is willing to encourage investment. She said combining tax incentives with some form of joint state investment in research and development will send a signal to industry this is something the state is serious about pursuing.

In response to a question from Senator Triplett, Mr. Smith said he does not know the exact amount of federal investment in carbon capture, storage, and injection technology but does know that it ranges in the billions and is typically derived from sources such as the United States Department of Energy or the federal Environmental Protection Agency.

In response to a question from Senator Triplett, Ms. Agalliu said, in regard to working with the EERC, IHS Energy has yet to reach out to EERC on a personal basis but has reviewed all public material published by EERC. Ms. Agalliu said she is willing to work more closely with EERC but is not sure the extent to which EERC is willing to part with any of its proprietary information.

Senator Cook requested IHS Energy provide an index page in the final report defining all of the acronyms that are referenced in the document.

Chairman Unruh further requested that the final report measure CO^2 in tons rather than MCFs.

In response to a question from Representative Froseth, Ms. Agalliu said the potential cost of any fines or penalties associated with noncompliance with the Clean Power Plan have not been factored into the model. Ms. Agalliu said there is a cost of CO^2 and there is a price of CO^2. She said the cost of CO^2 is borne by the power plant and may be transferred to the power plant's electricity consumers. She said the public will ultimately pay for additional costs imposed on power plants forced into compliance with the Clean Power Plan. She said the cost to purchase CO^2 for enhanced oil recovery purposes is currently \$1 to \$2 per MCF. She said it is unlikely anyone would buy CO^2 at the \$5 price point it would need to be sold for if captured from a power plant. She said the technology is currently too expensive to make the cost of producing CO^2 from power plants economically feasible for use in CO^2 enhanced oil recovery.

Senator Cook said this information highlights the dilemma the committee faces. He said if the state can figure out how to achieve enhanced oil recovery using CO^2 industry would likely be willing to pay a higher premium for CO^2, which would make it easier for power plants to address the costs of retrofit technology. He said the state needs to figure out how to retrofit plants to capture enough CO^2 for enhanced oil recovery and incentives will likely be required to accomplish these two objectives.

Mr. Smith said the biggest obstacle to using CO^2 for enhanced oil recovery is the limited supply of CO^2. He said enhanced oil recovery has been successful in the Permian Basin because there are natural sources of CO^2 that can be tapped into and piped to oil fields in a relatively cheap manner. He said sources in southwest Wyoming are also relatively cheap when compared to the $3 to $4 investment per MCF that would be required to obtain CO^2 from smokestacks. He said advances in technology are required to bring down those retrofit costs.

In response to a question from Senator Hogue, Ms. Agalliu said IHS Energy could expand its model to take federal incentives into account.

Representative Headland said it seems the economics associated with obtaining enough CO^2 for enhanced oil recovery is more of a driver in a company's decisionmaking process than the tax policy. He said the cost of CO^2 in both scenarios that were presented, coupled with dependence on the price of oil, seem to be more of a problem than the current tax policy.

Ms. Agalliu said it is one thing to run a pilot, but a full-blown commercial project requires a tremendous amount of planning and contracting and would likely take years to get off the ground. She said it is not likely the state would see projects beginning in 2016 or 2017 because it takes at least 3 to 5 years before a project like this could realistically commence. She said today it is more of a question of what needs to be done to incentivize industry to think more seriously about the possibility of engaging in projects in this state.

Mr. Smith said many of the CO^2 enhanced oil recovery projects you see today are full cycle, which means one company is taking on the entire process from capture to injection. He said a company will not undertake CO^2 enhanced oil recovery unless they have secured a relatively economical source of CO^2.

Senator Dotzenrod said there appears to be a great amount of uncertainty surrounding whether or not these projects will be successful. He said various uncertainties centering around whether or not the process will work may need to be sorted out before the committee can engage in a discussion regarding the most appropriate incentives that should be applied to incentivize the process.

Ms. Agalliu said more research and development will likely need to be conducted before companies will take the next steps toward project development.

Mr. Smith said the only way you will ever know if CO^2 enhanced oil recovery works in this state is if you get past the pilot stage and actually have an operator set up a project to gauge its economics.

Chairman Unruh thanked IHS Energy for its interim report and said the purpose of IHS Energy's visit today was to review the interim report and give the committee a chance to provide feedback for the preparation of the final report. She said she had some questions after hearing today's presentation and also wanted to reiterate Senator Triplett's suggestion that IHS Energy verify some of the assumptions used in the model with state resources such as EERC and the Tax Department.

In response to a question from Chairman Unruh, Ms. Agalliu said it would be the team's preference to receive any additional feedback from the committee within 1 week to allow sufficient time for peer review and editing of the final report.

Chairman Unruh said in regard to IHS Energy's previous question as to whether the report should be limited to just production and extraction taxes, the committee is willing to receive as many suggestions as IHS Energy wishes to provide and said IHS Energy should feel free to develop creative approaches. She said the committee will contact IHS Energy with a date for presentation of the final report.

In response to a question from Senator Triplett, Chairman Unruh requested IHS Energy provide the committee with an advance copy of the final report one week prior to the date scheduled for the in-person delivery to allow the committee time to review the material and come prepared with any comments or questions.

Senator Cook said IHS Energy should also be aware of any tax bills passed during the 2015 legislative session that provided incentives for CO^2 capture and enhanced oil recovery.

Comments by Interested Persons

Chairman Unruh invited comments by interested persons regarding the committee's study and the information contained in IHS Energy's interim report. No comments were received.

Chairman Unruh called on the Legislative Council staff for presentation of a memorandum entitled *Reservoir Protection and the Prevention of Waste*. The Legislative Council staff said additional information was requested regarding practices other states use to prevent waste with Texas and Oklahoma referenced as specific states of interests as both states have rather extensive reservoir protection acts. She reviewed the model definition of waste provided in the Interstate Oil and Gas Compact Commission's 2004 Model Oil and Gas Conservation Act. She said this information is pertinent to the committee's study as the committee is looking at the importance of maintaining pressure in a reservoir and the consequences that might result if that pressure is depleted. She provided a high-level overview of the regulations in place in Texas and Oklahoma.

Energy and Environmental Research Center

Chairman Unruh called on Mr. John A. Harju, Vice President for Strategic Partnerships, Energy and Environmental Research Center, for a presentation of information (Appendix D) regarding enhanced oil recovery techniques used in conventional reservoirs and in the Bakken Formation. Mr. Harju said he had a few comments regarding the information presented by IHS Energy and offered to provide assistance to IHS Energy during the final stages of its work. He said six pilot studies have been conducted to date which are relevant to the committee's study of enhanced oil recovery in the Bakken Formation. He said three of the six pilots projects have injected CO^2, two have injected water, and one has injected field gas. He said there are also a few fields screened out by IHS Energy that he would not have excluded. He said it was also his opinion that one-eighth mile spacing between wells would be more appropriate than one-fourth or one-half mile spacing. He said the threshold economics for CO^2 enhanced oil recovery are sensitive to a number of things including the amount of CO^2 required to produce each incremental barrel of oil. He said IHS Energy cited the cost of CO^2 under its high-case scenario as $3.50 per million cubic feet, which would equate to $60 per ton. He said, coincidentally, this is roughly the price at which retrofit technology would be economical to apply to the state's existing lignite plants. He said the estimated 2.2 BCF of CO^2 per day required for a full build out of the Bakken Formation is roughly the equivalent to the amount of CO^2 known today in the entire United States.

In response to a question from Senator Cook, Mr. Harju said he agreed with IHS Energy's comments that availability of CO^2 is a huge problem and probably the number one factor precluding growth of enhanced oil recovery.

Senator Cook said it seems ironic that too much CO^2 is a problem under the Clean Power Plan and too little CO^2 is a problem in regard to advancing enhanced oil recovery.

In response to a question from Representative Hatlestad, Mr. Harju said power plants in this state currently emit about 30 million tons of CO^2 annually, or 2 BCF per day, which is almost the precise amount quoted by IHS Energy as necessary for a full build out of the Bakken Formation. Mr. Harju said it would be a huge prize if this state could figure out how to capture CO^2 from power plants at a price that would make enhanced oil recovery economically viable. He said billions of dollars of federal research have been dedicated to researching the topic. He said EERC has worked on over 20 retrofit technologies so there is a lot of energy going into making carbon capture technology technically and economically viable.

Mr. Harju reviewed the differences between conventional fields and the Bakken Formation as well as the challenges of using enhanced oil recovery in the Bakken Formation. He said he does not think water flooding will be an effective next step in the Bakken Formation due to the nature of the rocks in that formation. He said the total United States production of oil using CO^2 enhanced oil recovery is currently 350,000 barrels per day. He said the majority of that production comes from west Texas with smaller amounts coming from Wyoming, Montana, Mississippi, and Louisiana. He said about 90 to 100 percent of the CO^2 injected into a reservoir will permanently remain in the reservoir. He said the United States Department of Energy estimates there are 137 billion barrels of recoverable oil that could be obtained in the United States using CO^2 enhanced oil recovery. He said there is currently a shortage of CO^2 in the United States so a policy question the state should consider addressing is whether the capture and transport of CO^2 should be encouraged.

Mr. Harju said he agreed with IHS Energy that the Beaver Lodge-Devonian Unit in Williams County is one of the better CO^2 enhanced oil recovery targets in the state. He said this unit is about twice the depth of the very prolific enhanced oil recovery projects conducted in Texas and Saskatchewan. He compared features of the Bakken Formation to features of the projects in west Texas and Saskatchewan. He said EERC typically assumes 80- to 160-acre well spacing as opposed to the 120-acre well spacing used in west Texas. He said one of the largest challenges an operator faces in a reservoir is trying to control the fluids. He said the more penetrations you have, the greater opportunity you have to control fluid movement.

Mr. Harju also reviewed the practice of unitization and said a field would need to be unitized before an enhanced oil recovery project could proceed. He said all of the wells within a field must be operated collectively so the costs and the proceeds of the operation are equitably distributed between all the owners of the field. He said fields in the Bakken Formation have yet to be unitized.

In response to a question from Senator Cook, Mr. Harju said he did not think unitization would be required for purposes of a field test.

Mr. Harju said CO^2 injected into a formation would not escape the formation. He said there are about 20 fields in this state that are technically and economically feasible for CO^2 enhanced oil recovery. He said some of the large fields are coincidentally located along the same route as the Dakota Gasification Company pipeline. He said the total amount of estimated incremental production from unconventional reservoirs in this state is between 300 billion to 900 billion barrels of oil and the total amount of CO^2 that could be produced in the state is roughly 30 million metric tons of CO^2 per year. He said only 4 to 6 percent of the oil in an unconventional reservoir is currently being recovered. He said any meaningful increase in the recovery factor translates into billions of barrels of oil. He said CO^2 is one of the leading resources that could be used to meaningfully change that recovery factor. He said EERC is working on solutions for some of the difficulties encountered in using CO^2 for enhanced oil recovery and said these solutions are currently in the research and development stage. He said EERC is grateful for the state's oil and gas research program and to the many companies that have acted as coinvestors in these efforts.

Mr. Harju said EERC has been able to extract 100 percent of the oil from samples of middle Bakken and Three Forks Formations rocks stored in the core library in Grand Forks. He said EERC has not seen the same rate of recovery in shales but is still seeing recovery rates of 75 to 85 percent in these samples. He said despite the lower recovery rates, there is about two to three times the amount of oil in shales as there is in the middle Bakken or Three Forks Formations, He said shales are where the oil really is. He said the work being conducted by EERC is very exciting as it has the potential to increase a 4 to 6 percent recovery factor to a 12 percent recovery factor. He said a project being undertaken in southeastern Montana required about 5 months of CO^2 injection before incremental production of oil was observed. He said EERC has learned that CO^2 can be pushed into a reservoir and production responses will occur. He said the production improvements that were predicted in the laboratory did not match the observations in the field. He said one of the causes for lower than anticipated production improvements seem to be the presence of fractures within the rock. He said in one of the pilot tests, a large amount of CO^2 was injected and within 2 weeks, CO^2 was observed in a well two miles away and there was no appreciable oil response. He said EERC is working with two companies towards additional pilot projects that could occur as early as this summer. He said EERC is also working with externs from the law school in Grand Forks to research appropriate ways to legally approach unitization in unconventional fields. He said these fields will need to be unitized in order to prevent waste and protect the correlative rights of all owners. He said there are innovative injection and production schemes that need to be developed and tested but EERC is making progress. He said even though initial field tests have not been successful, they have still been instructive. He said the technology for CO^2 enhanced oil recovery is likely years away and the price of oil and the availability of CO^2 will be large drivers in the success of enhanced oil recovery projects.

Mr. Harju said the good news is there may be some new price drivers on enhanced oil recovery in light of the restrictions imposed under the Clean Power Plan that may make CO^2 capture more economical. He said despite current limitations, the state needs to ask whether it wants to recover only 5 percent of the resources in that reservoir and if it wants to leave 800 years of mineable coal in the ground. He said CO^2 enhanced oil recovery is a multi-generational opportunity for this state and a way to secure future wealth if we can figure out how to make this technology work.

In response to a question from Senator Cook, Mr. Harju said CO^2 would be shipped as a refrigerated liquid, as opposed to a warm, dense phase supercritical fluid, if shipped by truck. Mr. Harju said 30 to 40 tons of CO^2 could fit in a truck. He said in current CO^2 enhanced oil recovery projects, the price of CO^2 delivered by pipeline is roughly \$20 to \$30 per ton, whereas the price of CO^2 delivered by truck is roughly \$150 to \$200 per ton.

In response to questions from Senator Triplett, Mr. Harju said EERC has not determined whether the fractured nature of the reservoir is due to naturally occurring fractures or fractures that have been created as a result of hydraulic fracturing. Mr. Harju said he is aware of one test where CO^2 was used as a fracking medium. He said there are challenges in using CO^2 as a fracking medium. He said CO^2 does not have the ability to carry proppants as far into the reservoir because it does not have the same density and viscosity as water. He said the use of water for fracking also has the benefit of dissolving large amounts of salt within the formation. He said water that goes into a reservoir consists of about 30 percent salt by the time it is removed. He said removal of this amount of salt creates porosity in the reservoir, which increases the permeability and productivity of a reservoir. He said similar results would not be achieved using CO^2 as a fracking medium. He said the federal government has spent about

$8 billion to $20 billion on research focused on carbon capture and storage. He said there was a time the federal government invested considerable sums in enhanced oil recovery research, but the interest in this area has dropped off over the last several decades. He said he would estimate the state has funded roughly $2 million of Bakken Formation enhanced oil recovery research over the last 10 years. He said any state funding EERC receives is typically leveraged heavily with incremental federal investment and corporate investment. He said state funding has been critical in helping advance understanding of enhanced oil recovery.

Department of Mineral Resources

Chairman Unruh called on Mr. Bruce E. Hicks, Assistant Director, Oil and Gas Division, Department of Mineral Resources, for a presentation (Appendix E) of information pertaining to unitization and enhanced oil recovery techniques. Mr. Hicks discussed the unitization process, units that have been approved, enhanced oil recovery results, Bakken Formation development, and Bakken Formation enhanced oil recovery potential. He said 127 units have been approved and water was injected into the majority of those units. He said high pressure air has been injected into some units and air injection was fairly successful in Bowman County. He said propane, CO^2, polymers, nitrogen, and other fluids have also been injected on a limited basis. He said pilot projects are typically conducted within one spacing unit and the Department of Mineral Resources requires all of the wells around that spacing unit to be monitored throughout the course of the project. He said the operator of the project must immediately notify the department if any type of enhanced oil recovery is seen in outlying wells so the department can properly address the rights of other owners. He said the department also requires followup on the project to ensure it is being conducted in the manner for which it was approved.

Mr. Hicks discussed the amount of original oil in place that can be produced in a conventional reservoir and said 15 percent of the oil can be recovered through primary recovery methods, with an additional 15 percent recovered using secondary recovery methods, and an additional 10 percent recovered using tertiary recovery methods. He said in an unconventional reservoir, about 3 to 5 percent of the original oil in place can be recovered using primary recovery methods. He said at this point, the Department of Mineral Resources is not sure which methods will be successful in unconventional reservoirs for purposes of secondary and tertiary recovery. He said most pilot projects have been conducted on a small scale and for a very short duration. He said the Bakken Formation encourages enhanced oil recovery projects because of its uniform spacing. He said 1.1 million barrels of oil are currently produced in this state per day and it is projected that production could reach 2 million barrels per day at some point in the future. He said 13,000 wells are currently producing in this state and 84 percent of those wells, nearly 11,000 wells, are located in the Bakken and Three Forks Formations. He said the department anticipates that 40,000 additional wells will be drilled in this state.

Mr. Hicks said the enhanced oil recovery projects that have been approved by the Department of Mineral Resources include enhanced oil recovery projects using water injection and CO^2 injection. He said the results of the pilots projects have generally been inconclusive. He said projects are ongoing so the department anticipates receiving more information in the future. He said the potential for enhanced oil recovery in the Bakken Formation is huge. He said there are over 300 billion barrels of original oil in place in the Bakken Formation, so if enhanced oil recovery methods could increase recovery rates by even 1 percent that would equate to an additional 3 billion barrels of oil. He said to provide some perspective on the magnitude of this figure, as of today the state has only produced a little over 3 billion barrels of oil since the state started producing oil in 1951. He said the amount of oil the state could potentially recover would be a huge prize if enhanced oil recovery can be achieved.

EmPower North Dakota Commission

Chairman Unruh called on representatives of the EmPower ND Commission regarding an update on the recent activities of the commission and the commission's perspective on energy policy.

Mr. Mike Fladeland, Manager, Energy Business Development, Economic Development and Finance Division, Department of Commerce, and Member, EmPower ND Commission, said the energy policy committee was established by the 2007 Legislative Assembly and has since been known as the EmPower ND Commission. He said the commission has 14 voting members and 3 ex officio members. He said the commission meets during the interim to gather input from various parties and formulate recommendations for energy policy. He said since September 2015 the commission has heard from industry representatives, government agency representatives, and representatives from the cities, counties, and state. He said the commission elected to concentrate its focus on three main areas this interim. He said subcommittees were formed to address research and development, infrastructure, and regulatory issues.

Mr. Jason Bohrer, President and CEO, Lignite Energy Council, and member, EmPower ND Commission, reported on the work of the commission's regulatory subcommittee. He said the regulatory subcommittee discussed regulations at both the state and federal level which might be of concern in this state. He said the primary federal regulation that brought industry members together was the Clean Water Rule of the federal Clean Water Act which was released last year. He said various energy industry actors were able to come together on a shared message regarding this rule. He said the rule has the power to drastically impact how this state engages in energy extraction. He said the commission submitted comments on the rule and the rule has currently been stayed by the courts. He said another notable federal regulation is the Clean Power Plan, which he has discussed with the committee on previous occasions.

Mr. Bohrer reviewed 2015 Senate Bill No. 2037 and said the purpose of the bill was to achieve parity among energy industries by phasing out some incentives and modifying other incentives. He said the bill aimed to remove the sunset clause on the sales tax exemption for wind power generating facilities and extend the sales tax exemption pertaining to new coal mining. He said the goal of the bill was to provide an equal playing field for all industries as it related to sales tax exemptions. He said the bill was ultimately unsuccessful, but the commission still sees a need to look at some type of mechanism to achieve parity between the various energy industries. He said changes were also made to the duration of certain oil and gas incentives during the prior legislative session. He said the regulatory subcommittee built upon the work completed last session to try and formulate an incentive for enhanced oil recovery that would work hand-in-hand with some of the challenges the coal industry will likely be facing as it tries to comply with the Clean Power Plan.

Mr. Bohrer outlined the various enhanced oil recovery incentives passed during the 2013 and 2015 legislative sessions and the rationale for incentivizing the use of CO^2 for enhanced oil recovery. He said the subcommittee understands why concerns were raised during the 2015 legislative session regarding the provision of an indefinite exemption for CO^2 enhanced oil recovery and said the subcommittee discussed ways an incentive related to CO^2 enhanced oil recovery could be modified to give legislators the certainty they need to meet defined policy objectives. He said the commission discussed an incentive for CO^2 enhanced oil recovery that would be capped based on a certain amount of CO^2 used or a certain number of barrels of oil recovered rather than capped based on a 10-year duration. He said the goal of the incentive is to maximize the value of using CO^2 produced from power plants, rather than geologic CO^2, for use in enhanced oil recovery. He said the incentive would assist industry as it tries to comply with the requirements of the Clean Power Plan and would give the state the biggest bang for its buck by incentivizing the use of CO^2 from North Dakota sources for enhanced oil recovery. He said considering the state needs to reduce its CO^2 emission by 13 million tons in order to comply with the Clean Power Plan, the incentive could potentially be provided for the first 13 million tons of CO^2 sequestered. He said this is one form the incentive could take. He said this type of structure would essentially front load the incentive to reward early actors for taking a risk in developing technology to capture CO^2 from coal plants and for early action in the oil fields using CO^2 for enhanced oil recovery. He said a limit placed on tons of CO^2 used or barrels of oil recovered would give the state certainty regarding the price tag associated with the incentive. He said the subcommittee will be reviewing IHS Energy's interim report and will continue to work with EERC to determine which figures would best be applied to the incentive based on the technology that is available to power plants. He said the subcommittee welcomes any input the committee may have as the subcommittee continues to craft the concepts surrounding this incentive.

In response to a question from Senator Cook, Mr. Bohrer said the subcommittee has not discussed specifying a price at which CO^2 must be sold. Mr. Bohrer said as he described the incentive today, the incentive would benefit the oil company. He said as Mr. Harju previously mentioned, the technology for carbon capture and enhanced oil recovery currently exists but as it applies in Canada, the Canadian government owns all of the apparatuses involved in the process from the carbon capture to the injection of CO^2 so the situation in this state would be different because we would need to focus on how the incentive would encourage private business decisions. He said the subcommittee's thoughts are that providing an incentive to the first actor to engage in the process might encourage that actor to purchase CO^2 at a higher price than they otherwise would be willing to pay because that actor would reap the benefits associated with being the only operator producing oil using this specific recovery method.

In response to a question from Chairman Unruh, Mr. Bohrer said the subcommittee has not compared how federal and state tax burdens apply to each of the different fuel types within the state, but said it was a good suggestion that he would take back to the subcommittee. He said the goal is to ensure a level playing field for all of the energy producers in this state. He said he would see if the subcommittee could provide additional input or data on that topic.

Chairman Unruh said she appreciated the commission's suggestions regarding the committee's study of CO^2 enhanced oil recovery and looked forward to continuing to work with the commission through the remainder of the interim.

Mr. John Weeda, Director, North Dakota Generation Operations, Great River Energy, and member, EmPower ND Commission, provided information (Appendix F) on the work of the commission's research and development subcommittee and information on electric markets. He said the subcommittee invited various entities including EERC, North Dakota State University, the Electric Power Research Institute, and the Lignite Energy Council to provide input on the topic of research and development to help the subcommittee assess funding adequacy. He said the subcommittee's findings were well received by the full commission, but the full commission has yet to take any final action regarding the subcommittee's work. He reviewed the pathway from the initial idea and basic research stage to the point of commercial deployment and said the basic research stage has traditionally been funded by the federal government though this funding seems to be drying up. He said the subcommittee identified opportunities the state might want to address and the items it could possibly afford to fund. He said the state needs a vision of how the energy industry will work together for its mutual benefit to address carbon capture and the utilization of CO^2 for enhanced oil recovery. He said advances in technology are needed in order to capture the amount of CO^2 required for enhanced oil recovery. He said a process that offers the most promise is the Allam Cycle, but that process is still a long way from being commercialized. He reviewed the anticipated costs associated with further development of the Allam Cycle and said the figures are quite large. He said federal and state dollars that were received when the DryFining process was being developed gave industry members in this state the courage to go forward and develop the technology. He said the subcommittee is eager for the committee's feedback on its research thus far and welcomes suggestions regarding whether the subcommittee should refocus its efforts or continue to further develop the ideas presented today.

Mr. Weeda also reported on the work of the infrastructure subcommittee and said the subcommittee believes a large amount of progress has been made in this area. He said one item the subcommittee focused on is how to bring value added energy to this state. He said the subcommittee realizes that the surge funding seen in the past will likely not be available during the upcoming legislative session. He said the subcommittee received recommendations from the Upper Great Plains Transportation Institute regarding funding priorities and one of the ideas provided by the institute was to offer low-interest loans to buydown the debt in communities where funding may be overstretched due to dropping oil prices. He said the subcommittee also supports continued funding on a priority basis for completion of existing critical needs projects and emergency medical services. He said right-of-way issues and easements are another area of concern as confusion often arises regarding which jurisdiction has authority in certain situations.

In response to a question from Senator Bekkedahl, Mr. Weeda said most power plants are located relatively close to water. Mr. Weeda said the Spiritwood Station was located away from water because it had to be placed in the Spiritwood area in order to serve Cargill. He said in regard to why other projects have been located away from water sources, the only reasons he could speculate is that the plant operator felt the diversity of economic development within the state outweighed the complications of getting water to the plant. He said he understands that getting water to other parts of the state requires a great deal of investment. Senator Bekkedahl said he is not sure why industries other than coal have not looked to develop in the Missouri River corridor. Mr. Weeda said the commission has not had that discussion but he will take that feedback to the subcommittee for further consideration.

Senator Cook asked if any projects have resulted from the 2015 legislation that allowed a sales tax exemption for power plants that restructured to capture CO^2 and pipelines that were constructed to deliver CO^2 to the Bakken Formation. In response, Mr. Bohrer said projects are still ongoing but they have been given less priority as a result of decreasing oil prices. He said development of the project referenced during the 2015 legislative session has shifted from the petroleum plant to the power plant.

In response to questions from Senator Cook, Mr. Bohrer said the plant in Texas is close to being completed and industry representatives from this state hope to tour the plant to see what lessons can be applied in this state. Mr. Bohrer said the plant in Kemper County, Mississippi is not an Allam Cycle project. He said the plant in Mississippi is simply a plant built with the best technology available to date. He said the Allam Cycle is a next generation leap forward that takes the complexities of the Kemper County project and shrinks them down by about 40 percent. He said the only thing the two projects have in common is that they both comprise of new technology. He said he could not guarantee that an Allam Cycle project in this state would not have cost overruns as all risk cannot be eliminated, but said the investors in the Allam Cycle project in this state are much more risk adverse than those involved in the Kemper County project. He said any risk relating to failure of the turbine design in the Allam Cycle project in this state would be borne entirely by the industrial partners involved with the project.

Mr. Weeda said he knows the manager of the plant in Texas and the manager is eager to get started. He said the enthusiasm for the project in Texas has not been dampened by falling oil prices.

Mr. Weeda reviewed information relating to electrical markets and said the current price of electricity in North Dakota is $13.86 per megawatt hour for a 24-hour period. He said most electrical generating companies sell what they generate into the market the day before. He said operators in this state market electricity to the Midcontinent Independent System Operator market and the Southwest Power Pool. He said 45 to 50 percent of the energy generation in the Midcontinent Independent System Operator market comes from coal. He said a substantial part of the generation in that market is also comprised of wind-powered generation. He said this state is competing more with coal and wind generation than with natural gas. He said the price of natural gas has dropped tremendously. He said at one point natural gas was high at $15 to $16 per dekatherm, but now prices as low as $1.60 per dekatherm. He said over time there has been a lot of volatility associated with gas pricing. He said fracking has produced a large supply of natural gas within the state.

Mr. Weeda explained how wind energy works with other energy sources and said the amount of wind energy generated in the summer is about half of the amount generated in the spring. He said during the months of June, July, and August, other energy sources have to fill the gaps created by reduced wind generation. He said gas and wind are energy sources that complement one another. He said when prices fall below the $13.86 threshold, generation plants will be shut down until prices rise. He said it is difficult for the larger base load plants to go on and offline at will. He said it takes anywhere from 8 to 15 hours for a plant to go from offline status to producing power. He said some of the older facilities are seeing a distinct drop in the running capacity time of the plant. He said the dropoff in the running capacity of coal plants is something that could effect power generation from coal at times when it is needed to supplement wind-generated power. He said the impact wind generation is having on other generation plants is similar to the impacts that are anticipated as a result of the Clean Power Plan. He said gas is expected to increase and coal is expected to decrease as a power source for United States power generation throughout 2016.

In response to a question from Representative Headland, Mr. Weeda said growth in the power industry is very flat. Mr. Weeda said most utilities are forecasting growth in the neighborhood of 1 percent, whereas prior to 2008 most utilities were experiencing growth at a rate of 3 to 5 percent per year. He said the commission expects to see flat if not declining demand throughout the 2017 legislative session.

In response to a question from Senator Cook, Mr. Weeda said the full commission has yet to weigh in on the expiring energy industry sales tax exemptions. Mr. Weeda said the commission expects to present more finalized recommendations to the interim Energy Development and Transmission Committee sometime in June or July.

Chairman Unruh said the committee might try to sit in on the Energy Development and Transmission Committee's meeting when EmPower ND presents its final recommendations or might request an additional presentation from EmPower ND at a later date.

Committee Discussion and Directives

Chairman Unruh reminded the committee that any additional recommendations for items to include in the final report must be received within 1 week from today. She said committee members should submit any comments to the Legislative Council staff for compilation and submission to IHS Energy.

No further business appearing, Chairman Unruh adjourned the meeting at 4:00 p.m.

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Emily L. Thompson
Counsel

ATTACH:6