

TAXATION COMMITTEE

The Taxation Committee was assigned two studies related to enhanced recovery of oil and gas:

- Section 4 of Senate Bill No. 2318 (2015) directed a study of the oil extraction tax exemption available for incremental production from a tertiary recovery project that uses carbon dioxide (CO₂). The study required consideration of the potential benefits and costs to industry, the state, and the environment of using CO₂ enhanced recovery methods. The study directed the Legislative Management to secure assistance from the Energy and Environmental Research Center (EERC) to analyze potential future usage of CO₂ in oil recovery operations in the Bakken and Three Forks Formations, the potential production and environmental benefits of that usage for energy industries in this state, the economic conditions in which that usage is feasible for oil producers, and the estimated fiscal effect of that usage for the state and political subdivisions.
- Section 42 of Senate Bill No. 2015 (2015) directed a study of the current scientific and economic information regarding oil and gas recovery and enhanced recovery techniques, including the use of CO₂, the timeline for implementing the techniques, and the estimated future annual economic impact, to evaluate existing and alternative tax incentives and recommend tax incentives that under current and foreseeable conditions, and within different oil formations, would best serve the interests of the state, political subdivisions, and fossil fuel energy production industries. Section 11 of the bill provided an appropriation of \$400,000 to the Legislative Council for purposes of securing a consultant to study oil and gas tax incentives and oil and gas recovery techniques.

The Legislative Management directed the committee to receive two reports:

- Reports from the Tax Commissioner from compiled reports from counties and school districts receiving allocations of oil and gas gross production tax revenues describing funds received, expended, and unexpended (North Dakota Century Code Section 57-51-15).
- A compilation and summary of state grantor reports filed annually by the Department of Commerce and the reports of state agencies that award business incentives for the previous calendar year (Section 54-60.1-07).

Committee members were Senators Jessica Unruh (Chairman), Brad Bekkedahl, Dwight Cook, Jim Dotzenrod, David Hogue, Lonnie J. Laffen, and Connie Triplett and Representatives Wesley R. Belter, Jason Dockter, Glen Froseth, Patrick R. Hatlestad, Craig Headland, Tom Kading, Jim Kasper, Jerry Kelsh, Alisa Mitskog, Vicky Steiner, and Marie Strinden.

ENHANCED OIL AND GAS RECOVERY STUDIES

Background

Ranked second out of 31 oil- and gas-producing states, North Dakota had 12,659 active wells in May 2015, and an average rig count of 83 rigs. According to information published by the Industrial Commission, statewide production averaged 1,201,159 barrels of crude oil and 1,625,624 million cubic feet (mcf) of gas per day in May 2015. For comparison, in May 2014 there were 10,916 active wells, 189 rigs, 1,040,625 barrels of crude oil per day, and 1,195,410 mcf of gas per day. The highest rig count to date was recorded in May 2012 at 218 rigs. The highest producing month was recorded in December 2014 with average daily production totals reaching 1,227,344 barrels of oil per day. Fluctuations in production lead to an ever changing landscape of infrastructure and facilities.

The state has one longstanding refinery, the Tesoro Mandan Refinery, with a processing capacity of 71,000 barrels of oil per day. A second refinery, Dakota Prairie Refining, located west of Dickinson, was completed in May 2015 and is designed to process 20,000 barrels of oil per day. The refinery was acquired in June 2016 by Tesoro and renamed the Tesoro Dickinson Refinery. The state also has several natural gas processing facilities with the three largest being the Hess Tioga plant, with a processing capability of 250 mcf of gas per day, and the ONEOK Garden Creek II and III facilities, with a processing capability of 240 mcf of gas per day. According to information published by the North Dakota Pipeline Authority, state infrastructure also includes 15 crude oil pipelines, 9 natural gas pipelines, 3 product pipelines, and 1 CO₂ pipeline.

The state's coal resources are in the form of lignite, which is a low-grade, low-sulfur coal. According to information published by the federal Energy Information Administration, mines in this state produced 27,369 short tons of coal in 2013, ranking this state ninth among the 25 coal-producing states. Active coal mines in the state include the Beulah Mine, Center Mine, Falkirk Mine, and Freedom Mine. The state also houses several coal-powered generation plants, the largest of which are the Coal Creek Station, Antelope Valley Station, Milton R. Young Station, Leland Olds Station, Coyote Station, and the Stanton Station. The North Dakota Geological Survey estimates western North Dakota contains roughly 351 billion tons of lignite and 25 billion tons of economically mineable coal.

Oil and Gas Gross Production Tax

The oil and gas gross production tax is imposed in lieu of property taxes on oil- and gas-producing properties pursuant to Chapter 57-51. As enacted in 1953, the oil and gas gross production tax was a tax of 4.25 percent of gross value at the well of oil and gas. The total net proceeds collected from the gross production tax was \$306,000 in fiscal year 1954.

In 1957 the rate of the tax was increased to a rate of 5 percent of gross value at the well of oil and gas. From 1957 to 1981 the distribution formula for proceeds of the gross production tax remained the same in Section 57-51-15. During that time, the first 1 percent of gross value at the well of oil and gas produced was credited to the general fund. After deduction of the general fund's 1 percent share in each county, the balance was distributed as follows:

- The first \$200,000, 75 percent to the producing county and 25 percent to the general fund.
- The next \$200,000, 50 percent to the producing county and 50 percent to the general fund.
- All remaining revenue, 25 percent to the producing county and 75 percent to the general fund.

The distribution formula was amended by the Legislative Assembly several times in subsequent years.

In 1991 the tax on gas was changed from a tax of 5 percent of the gross value at the well to an annually adjusted flat rate per mcf. An additional gross production tax exemption was added in 2003 to provide for a 24-month exemption for new or recompleted shallow gas wells.

A 2009 amendment by House Bill No. 1304, as amended by House Bill No. 1324, significantly increased allocation of oil and gas gross production taxes to political subdivisions and the oil and gas impact grant fund. The bill also provided that within 60 days after the end of each fiscal year, the board of county commissioners of a county that has received oil and gas gross production tax revenue allocations must file a report with the Tax Commissioner showing the amount received by the county, the amount expended for each purpose to which the funds were devoted, the share of county property tax revenue expended for each of those purposes, and the amount of unexpended funds remaining at the end of the fiscal year. The bill required the Tax Commissioner to compile the information from the reports and provide a report to the Legislative Management.

Laws relating to flaring of gas from oil and gas wells were revised by 2013 House Bill No. 1134, the statutory authority governing state-tribal oil and gas tax agreements was amended by 2013 House Bill No. 1005, and the North Dakota outdoor heritage fund was established by 2013 House Bill No. 1278.

Oil Extraction Tax

On November 4, 1980, the voters of the state approved Initiated Measure No. 6 on the general election ballot and established an oil extraction tax as a companion tax to the oil and gas gross production tax. The oil extraction tax is levied on the extraction of oil from the earth pursuant to Chapter 57-51.1. As originally enacted, the tax rate was established at 6.5 percent of the gross value of oil at the well, subject to full or partial exemptions. The initial extraction tax law provided exemptions for oil exempt from gross production taxes, up to 100 barrels per day of oil owned by a royalty owner, and oil from a stripper well, defined as a well producing 10 barrels or less of oil per day.

Oil extraction tax revenues were to be allocated 45 percent to the general fund, 45 percent to education funding, and 10 percent to water pipeline and resources trust fund uses. The allocation formula was amended in 1981 to allocate 30 percent to the general fund, 60 percent to education funds, and 10 percent to the resources trust fund. The allocation formula was amended again in 1983 to allocate 90 percent to the general fund and 10 percent to education funds.

In 1987 the 10 barrel per day limitation for stripper well properties was left in place for wells of a depth of 6,000 feet or less, but the limit was increased to 15 barrels per day for wells of a depth of 6,000 to 10,000 feet and 20 barrels per day for wells of a depth of more than 10,000 feet. For wells drilled and completed after April 27, 1987, and for qualifying secondary or tertiary recovery projects, the rate of tax was reduced from 6.5 to 4 percent of gross value at the well. In addition to the rate reduction, new wells completed after April 27, 1987, were given a full extraction tax exemption for the first 15 months of production. A trigger provision was included so that the rate would return to 6.5 percent if the average price of crude oil between June 1 and October 31 of any year was \$33 per barrel or more. The royalty owner exemption was eliminated in 1987.

In 1989 an exemption was created for production during the first 12 months after a well had been worked over. The exemption required filing of a notice of intent to begin a workover project with the Industrial Commission before beginning the project. A qualifying project was required to have a cost of at least \$65,000, which was reduced to \$30,000 if production increased by at least 50 percent during the first 2 months after completing the project. The exemption was limited to wells producing no more than 50 barrels of oil before beginning the project. The trigger mechanism was applied to the workover exemption.

In 1991 the trigger mechanism was adjusted to provide that if the oil price exceeded \$33 per barrel for any period of 5 consecutive months, the exemptions and rate reductions would not apply, rather than being based on June to October prices. A reverse trigger also was instituted to reinstate the reduced rates and exemptions when the price for a barrel of crude oil was less than \$33 for any consecutive 5 months. Other 1991 legislation provided for a 5-year exemption for oil produced from a secondary recovery project and a 10-year exemption for oil from a tertiary recovery project. The legislation required Industrial Commission certification of the project as qualifying for the exemption. The exemptions applied only to incremental production, defined as the total amount of oil produced minus the amount of oil that had been produced prior to the recovery project.

In 1993 the exemption for the first 12 months of production after a workover project was amended to eliminate the minimum investment of \$30,000 if production was increased at least 50 percent in the first 2 months after completing the project. The change retained the \$65,000 level of spending that would qualify the project for exemption if production increased by less than 50 percent. The bill also reduced the tax rate from 6.5 to 4 percent for production from a workover well after the 12-month exemption period.

In 1995 a 24-month oil extraction tax exemption was created for production from a horizontal well. The bill created a 10-year exemption for production of oil from a well that had been inactive for 2 years and a 9-month exemption for production from a horizontal re-entry well. The inactive well and horizontal re-entry well exemptions were made subject to the trigger mechanism. The limit on stripper well classification for wells deeper than 10,000 feet was increased from 20 to 30 barrels per day. Other 1995 legislation required certification by the Industrial Commission of qualifying status for wells eligible for exemptions or rate reductions. The allocation formula also was amended in 1995 to provide 60 percent to the general fund, 20 percent to education funding, and 20 percent to the resources trust fund.

In 2001 the trigger provision for exemptions and rate reductions was amended to clarify when the trigger was to become effective.

In 2003 an Oil and Gas Research Council was created and an oil and gas research fund was established with a continuing appropriation provided. A temporary exemption from gross production tax was provided for gas produced from shallow gas wells, with an expiration date of June 30, 2007. The 2-year inactive well exemption was amended to clarify the definition of a 2-year inactive well and to provide an 18-month provision to qualify the well for an exemption to be consistent with other oil extraction tax exemptions. The workover well exemption was amended to remove the requirement that a notice of intention must be filed before a workover project is commenced to qualify for an exemption.

In 2005 the Legislative Assembly provided for a sales and use tax exemption for CO₂ used for the enhanced recovery of oil or natural gas and increased the oil and gas research fund allocation to \$1.3 million per biennium after the 2003-05 biennium. A sales tax exemption also was provided for machinery, equipment, and related facilities for reducing emissions, increasing efficiency, or enhancing reliability of equipment of a new or existing oil refinery or gas processing plant.

Legislation in 2007 provided an oil extraction tax reduction to 2 percent for the first 75,000 barrels of oil during the first 18 months after completion from a horizontal well drilled and completed in the Bakken Formation from July 1, 2007, through June 30, 2008. The gross production tax exemption for shallow gas was made permanent for the first 24 months of production. An increase was provided from \$1.3 million to \$3 million per biennium in the amount of oil extraction tax revenues to be deposited in the oil and gas research fund.

The Governor was given authority by 2007 Senate Bill No. 2419 to enter agreements with the Three Affiliated Tribes of the Fort Berthold Reservation relating to taxation and regulation of oil and gas exploration and production within the boundaries of the Fort Berthold Reservation.

A 2009 amendment by House Bill No. 1235 provided a contingent rate reduction in the oil extraction tax which reduced the oil extraction tax rate for horizontal wells from 6.5 to 2 percent during the time the rate reduction was in effect. Existing law provided a complete oil extraction tax exemption that triggered into effect if the price of oil for 5 consecutive months remained below the trigger price.

A proposed constitutional amendment--2009 House Concurrent Resolution No. 3054--was placed on the 2010 general election ballot to establish the legacy fund as a constitutional trust fund. The measure was approved by about 65 percent of the voters and became effective for oil and gas production after June 30, 2011. The measure is now Article X, Section 26, of the Constitution of North Dakota, and requires 30 percent of total revenue derived from taxes on oil and gas production or extraction to be transferred to the legacy fund.

House Bill No. 1467 (2011) extended the effective date through June 30, 2013, for a triggered oil extraction tax rate reduction. If the trigger price was reached, the first 75,000 barrels or \$4.5 million of oil produced during the first 18 months

from a horizontal well would be subject to a reduced tax rate of 2 percent, instead of the normal 6.5 percent oil extraction tax. The rate reduction would become effective on the first day of the month following a month for which the average price of a barrel of crude oil was less than the trigger price of \$55.

Senate Bill No. 2129 (2011) made statutory changes to implement the requirements of Article X, Section 26, of the Constitution of North Dakota, requiring deposit of 30 percent of all oil and gas tax revenue in the legacy fund and 2011 House Bill No. 1451 eliminated the permanent oil tax trust fund and modified the manner in which biennial revenues from oil and gas taxes were designated for deposit in the general fund.

House Bill No. 1216 (2011) designated hydraulic fracturing--a mechanical method of increasing the permeability of rock to increase the amount of oil and gas produced from the rock--as an acceptable recovery process. This bill included an emergency clause and became effective April 11, 2011.

House Bill No. 1198 (2013) eliminated stripper well property status for wells drilled and completed or re-entered and recompleted after June 30, 2013. For wells drilled and completed or re-entered and recompleted after June 30, 2013, wells must be evaluated on an individual basis for stripper well status based on the production from the well and are not eligible for the stripper well exemption unless the individual well produces 30 barrels or less per day outside the Bakken and Three Forks Formations and 35 barrels or less per day for wells in the Bakken or Three Forks Formations. The bill provided for a reduced oil extraction tax rate of 2 percent for the first 75,000 barrels of oil produced during the first 18 months after completion of a well drilled and completed outside the Bakken and Three Forks Formations after June 30, 2013. The bill also revised the statutory framework for the state-tribal oil and gas tax agreement.

Senate Bill No. 2014 (2013) provided that within the oil extraction tax development fund, the portion to be allocated to the resources trust fund must be reduced by 5 percent and that amount must be transferred no less than quarterly into the renewable energy development fund, but not in an amount exceeding \$3 million per biennium. In addition, .5 percent of the amount credited to the resources trust fund must be transferred no less than quarterly into the energy conservation grant fund, but not in an amount exceeding \$1.2 million per biennium. The funding for renewable energy source development is to be administered by the Industrial Commission and the funding for programs for energy conservation development is administered by the Department of Commerce.

House Bill No. 1134 (2013) provided for a temporary exemption for oil and gas wells employing a system to avoid flaring. The bill provided liquids produced from a collection system utilizing absorption, adsorption, or refrigeration are exempt from oil extraction tax for a period of 2 years and 30 days from the time of first production.

Coal Severance Tax

The coal severance tax is imposed on the act of removing coal from the earth pursuant to Chapter 57-61. The tax is in lieu of both the sales and use taxes on coal and the property tax on minerals in the earth. The coal severance tax and the coal conversion tax were enacted in 1975 following a study conducted by the 1973-74 interim Finance and Taxation Committee. The coal severance tax applies to all coal severed for sale or industrial purposes, except coal used for heating buildings in the state, coal used by the state or any political subdivision of the state, and coal used in agricultural processing and sugar beet refining plants in the state or adjacent states. The tax is applied at a rate of 37.5 cents per ton. An additional two cents per ton tax is levied for the lignite research fund.

The revenue from the coal severance tax is deposited in the coal development fund. Seventy percent of the revenue in the fund is distributed to coal-producing counties according to the amount of coal each county produces and 30 percent is distributed to the constitutional trust fund administered by the Board of University and School Lands. The trust fund is used to supply loans to school districts for school construction and loans to cities, counties, and school districts impacted by coal development.

Legislation in 2013 provided during the first month of each calendar year beginning January 2014, the State Treasurer would be required to distribute funds to offset 50 percent of the county share of coal severance tax revenue allocated to a non-coal-producing county.

Coal Conversion Tax

The coal conversion tax is imposed in lieu of property taxes on coal conversion facilities pursuant to Chapter 57-60. The land on which the plant is located remains subject to property taxes. The coal conversion tax is applied as follows:

1. Electrical generating plants are subject to two separate levies. One levy is .65 mill times 60 percent of installed capacity times the number of hours in the taxable period and the other levy is .25 mill per kilowatt-hour of electricity produced for sale. Installed capacity means the rating shown on the nameplate assigned to the turbine of the power unit. The revenue generated from the .25 mill levy electrical generating plant production is deposited in the general fund. Eighty-five percent of the revenue from the .65 percent mill levy on installed capacity is

distributed to the general fund and 15 percent of the revenue is distributed to the county in which the electrical generating plant is located.

2. A coal gasification plant is subject to a monthly tax of 13.5 cents per thousand cubic feet of gas produced for sale or 4.1 percent of gross receipts, whichever is greater. Plants converting coal to products other than gas are taxed at 4.1 percent of gross receipts. The tax rate for a coal beneficiation plant is 20 cents per ton of beneficiated coal produced for sale or 1.25 percent of gross receipts, whichever is greater. Eighty-five percent of the revenue generated is distributed to the general fund and 15 percent of the revenue is distributed to the county in which the plant is located.

Legislation in 2005 provided sales tax and coal conversion tax exemptions and a reduced rate schedule for coal conversion facilities that engage in an environmental upgrade and repowering of a power plant. An "environmental upgrade" was defined as an investment of more than \$25 million in machinery, equipment, and related facilities for reducing emissions or increasing efficiency. "Repowering" was defined as an investment of more than \$200 million to modify or replace the process used to convert lignite coal into electric power.

Legislation in 2009 provided a coal conversion facility that achieves a 20 percent capture of CO₂ emissions during a taxable period receives a 20 percent reduction in the general fund share of the coal conversion tax, and an additional reduction of 1 percent for every additional 2 percentage points of its capture of CO₂ emissions, up to 50 percent reduction for 80 percent or more capture. The reduction is available for 10 years from the date of first capture or from the date the facility is eligible to receive the credit.

Legislation in 2013 provided a sales and use tax exemption for property used to construct or expand a facility for use of coal gasification byproducts.

Significant 2015 Legislation

Legislation in 2015 undertook a significant restructuring of oil extraction tax rates and exemptions and made several changes to tax distribution formulas.

House Bill No. 1476 provided for a restructuring of oil extraction tax rates and exemptions. The bill provides that beginning on January 1, 2016, the rate of extraction tax on all oil will be reduced from 6.5 to 5 percent. This rate is subject to change depending on the average price of a barrel of crude oil. If the average price of a barrel of crude oil exceeds the trigger price of \$90 for 3 consecutive months, the rate will increase to 6 percent on all oil extracted. The rate will remain at 6 percent until the average price of a barrel of crude oil falls below the trigger price of \$90 for 3 consecutive months, at which time the rate will revert to 5 percent on all oil extracted.

The bill eliminated several oil extraction tax exemptions. Production that will remain exempt from the oil extraction tax after December 31, 2015, included:

1. Production that is exempt from the gross production tax imposed by Chapter 57-51;
2. Production from stripper well property or an individual stripper well;
3. Incremental production from a secondary recovery project for 5 years from the date incremental production begins;
4. Incremental production from a tertiary recovery project that does not use CO₂ for 10 years from the date incremental production begins; and
5. Incremental production from a tertiary recovery project which uses CO₂ for 5 years from the date incremental production begins if the project is located outside the Bakken and Three Forks Formations and 10 miles or more outside an established field with a pool including the Bakken or Three Forks Formations. A subsequent change was made for the tertiary recovery exemption under Senate Bill No. 2015.

The bill also eliminated several oil extraction tax rate reductions. Production that will continue to be subject to a reduced oil extraction tax rate after December 31, 2015, includes production from wells drilled and completed outside the Bakken and Three Forks Formations and 10 miles or more outside an established field that includes either formation. The first 75,000 barrels of oil produced during the first 18 months after completion are subject to a reduced tax rate of 2 percent on the gross value at the well of oil extracted.

Senate Bill No. 2015 further amended House Bill No. 1476 to remove any references to whether CO₂ is used in a tertiary recovery project for purposes of determining the duration for which the oil extraction tax exemption will apply to incremental production. The bill also provided incremental production from a horizontal well drilled and completed within the Bakken and Three Forks Formations is not exempt from oil extraction tax from July 1, 2015, through June 30, 2017,

but is thereafter exempt for a period of 5 years from July 1, 2017, or the date incremental production begins, whichever is later.

House Bill No. 1176 provided for adjustments to the distribution formula for oil and gas gross production tax collections and made various changes to the distribution of revenues from the first 1 percent of the oil and gas gross production tax and the remaining 4 percent of oil and gas gross production tax.

The bill also expanded the reporting requirements for boards of county commissioners in each county receiving an allocation. The bill required that in addition to reporting the county's statement of revenues and expenditures, the board also must report the amounts allocated to the county's general fund and to townships within the county, and include the amounts expended from these allocations and the purposes of the expenditures. The bill also creates similar reporting requirements for each school district receiving an allocation.

House Bill No. 1377 created a political subdivision allocation fund for purposes of allocating oil and gas tax revenues to political subdivisions in oil-producing counties.

House Bill No. 1409 increased the funding for the North Dakota outdoor heritage fund from 4 to 8 percent of the remaining amount available from a one-fifth share of oil and gas gross production tax revenues.

Senate Bill No. 2318 provided a CO₂ capture system located at a coal conversion facility and any equipment directly used for enhanced recovery of oil or natural gas is exempt from all ad valorem taxes, and exempt from the coal conversion facilities privilege tax. The exemption does not apply to the land on which the capture system or equipment is located. The bill also created a sales and use tax exemption for materials used to construct or expand systems relating to the use of CO₂ for enhanced oil or gas recovery.

Senate Bill No. 2036 provided an exemption from the coal conversion facilities privilege tax for beneficiated coal produced for use within a coal conversion facility. The bill also extended the severance tax exemption available for coal purchased for improvement through beneficiation which is then used in an agricultural commodity processing facility or in any facility owned by the state or a political subdivision. This exemption was scheduled to expire on July 1, 2015. The bill also extended the sales tax exemption available on gross receipts from the initial sale of beneficiated coal that is not subject to tax under Chapter 57-60. The exemption was scheduled to expire on July 1, 2015. The bill extended the sales and use tax exemption available for certain purchases made by power plants classified as electrical generating plants which convert beneficiated coal into electrical power. This exemption was scheduled to expire on July 1, 2017.

Senate Bill No. 2343 required the Industrial Commission to provide a report to the Legislative Assembly, or the Budget Section if the Legislative Assembly is not in session, on the fiscal effect of any order, regulation, or policy regarding the control of gas and oil resources estimated to have a fiscal effect in excess of \$20 million in a biennium. The reporting requirements do not apply to spacing unit orders.

Senate Bill No. 2318 created a sales and use tax exemption for materials used to construct or expand a system for compressing, gathering, collecting, storing, transporting, or injecting CO₂ for use in enhanced recovery of oil or natural gas. The bill also provided for a coal conversion facilities privilege tax exemption for CO₂ capture systems.

Senate Bill No. 2035 created a sales and use tax exemption for materials used to construct a fertilizer or chemical processing facility.

Senate Bill No. 2037 expanded the items included in the definition of machinery and equipment used to produce coal from a new mine for purposes of a sales tax exemption and allowed for purchases of machinery or equipment made after December 31, 2010, to produce coal either directly or indirectly, to qualify for a refund of sales or use tax paid.

Prior Legislative Management Studies

The 2013-14 interim Energy Development and Transmission Committee studied likely changes to oil industry practices, production, impacts, and tax policy in the foreseeable future. The study directed the Legislative Management to obtain the services of an independent consultant with demonstrated insight into current and future production advances, including use of CO₂ and water or other means of enhancing production, effects of mature production areas on state and local tax policy, future infrastructure needs, and environmental considerations. The committee secured the services of a consultant who provided a final report containing an economic analysis of the Bakken and Three Forks Formations; information on the socioeconomic impacts of employment, population projections, and housing needs; and information on CO₂ enhanced oil recovery. The study of 2014-19 trends predicted North Dakota drilling levels will remain stable, North Dakota production could reach 2 million barrels per day, oil prices will average between \$70 and \$100 per barrel, and the global need for oil will absorb oil produced from United States shale. The study also identified technology changes that could affect production, including three dimensional field development, batch development, adequately

sized gathering systems, reliable systems to move product to market, field consolidation, and automation. The study highlighted environmental changes that could affect production including state regulations in border states, tribal regulations and development requirements, flaring regulations, and local regulation of crude oil trains. Policy issues that could affect production also were identified as potential crude export rule changes, the tightening of oil supply due to international conflict, and federal regulation changes on depletion allowances.

Enhanced oil recovery was identified as the next phase of development for the Bakken Formation. Around 5 to 6 percent of oil is recovered from the Bakken Formation and an increase in production of 1 percentage point would provide 3 billion to 5 billion barrels of oil. The study indicated CO₂ is the leader for enhanced oil recovery because CO₂ mollifies Bakken oil very well in tests, but the technology is not expected to be employed at high rates and will not substantially affect oil development in the next 5 years. Nitrogen was viewed as the leading mechanism for a few years, but has been found to be not compatible with Bakken oil. There are pilot projects in the Parshall field using water. The study found that the demand for CO₂ to fully apply enhanced oil recovery in the Bakken Formation is 2 billion to 3.2 billion tons, which conservatively would yield 4 billion to 7 billion barrels of incremental oil. The main concern of the oil industry was not the technology, but having enough CO₂. The output of CO₂ of all the power plants in this state is 33 million tons.

The study also indicated the Great Plains Synfuels Plant is the only commercial coal gasification facility producing synthetic natural gas. The plant produces CO₂, which is transported to Canada for sequestration; however, information was received indicating the contract would be expiring. The study found older oilfields near the existing CO₂ pipeline are capable of using CO₂ for enhanced oil recovery. The study indicated industry is catching up on infrastructure because of the provision of new capital, including capital to midstream pipeline companies, but the infrastructure is at least 1 year behind. The study also indicated it is harder to increase gas gathering than oil gathering capacity. Most gas gathering systems are overlaying two times the infrastructure to increase capacity. Oil gathering is designed with excess capacity, and there are other methods of increasing capacity. Large oil transmission lines are being built, and gathering systems will have multiple choices. The study found because of batch drilling and large initial productions, there will be issues with pipeline capacity.

Consultant Services

Request for Proposals

Section 11 of 2015 Senate Bill No. 2015 provided an appropriation of \$400,000 to the Legislative Council for purposes of securing a consultant to study oil and gas tax incentives and oil and gas recovery techniques. The committee made a request for proposals for consulting services and received two proposals. A proposal submitted by IHS Energy quoted a price of \$150,000 for technical analysis and \$245,000 for economic analysis for a total cost of \$395,000. A proposal submitted by a team headed by the EERC quoted a price of \$125,148 for technical analysis and \$274,624 for economic analysis for a total cost of \$399,772. The committee selected IHS Energy for the provision of consulting services.

Consultant Reports

The committee received monthly progress reports, an interim report, and a final report from representatives of IHS Energy. The reports indicated CO₂ enhanced oil recovery has the potential to yield 1.2 billion to 1.8 billion barrels of incremental production in the state over the next 20 years. The combined enhanced oil recovery activities in the Bakken Formation and in conventional fields has the potential to contribute approximately 6,000 jobs at the state level and 4,300 jobs at the national level, per year, for years 2022 through 2036. Direct revenues to the state from combined enhanced oil recovery activities in the Bakken Formation and in conventional fields could range from \$6.3 billion to \$9.7 billion during the study period. However, with the current lack of technology, low oil prices, and high costs of CO₂, the economics for CO₂ enhanced oil recovery do not work. A forward-looking process would be required to develop the technology to capture CO₂ in a more cost-effective manner and determine how to best inject CO₂ for purposes of enhanced oil recovery.

IHS Energy reviewed 800 fields during its study to determine which were best suited for enhanced recovery. Eighteen of the 800 fields were used for modeling purposes. The four primary components of the model included cost modeling, price forecasting, field development analysis, and fiscal modeling based on North Dakota's current fiscal system. The study determined use of CO₂ for enhanced recovery would be the most successful method of recovery and would also contribute environmental benefits.

The reports indicated there is more certainty regarding enhanced oil recovery in conventional plays because the technology used in conventional plays is proven. Barriers to enhanced oil recovery in conventional plays center around the availability and affordability of CO₂. The price of oil would need to exceed \$100 per barrel for the majority of enhanced oil recovery projects in conventional fields to break even in terms of costs. The high costs associated with enhanced oil recovery in conventional fields are related to a number of factors, including the age of the fields and the condition of the wells. The cost to convert an existing production well into an injector well is \$250,000 to \$300,000 and the cost to drill an entirely new injector well is \$5.6 million to \$6.6 million. Conventional fields that make the best candidates for CO₂ enhanced oil recovery are fields that have had a successful water flood.

Estimates based on modeling high- and low-case scenarios for conventional fields for the 2017 through 2036 timeframe range from 18 million to 35 million barrels of incremental oil with direct state revenues of \$139 million to \$439 million. Costs to industry range from \$1.3 billion to \$2.3 billion and the amount of CO₂ required is estimated at 5.7 million to 11.5 million metric tons during the same period. Significant recovery from enhanced recovery would likely not be seen until the mid to late 2020s.

The reports indicated a wide range of uncertainty surrounds enhanced oil recovery in unconventional fields. Factors that will impact the development of CO₂ enhanced oil recovery in unconventional plays include advances in technology, access to economical and abundant supplies of CO₂, and incentives that encourage the use of CO₂ for enhanced oil recovery. The technology pertaining to unconventional plays is only at the modeling and laboratory stage and is beginning to reach the pilot stage. Early modeling has been conducted for CO₂ enhanced oil recovery in the Bakken Formation, but the actual results from initial injection tests did not produce as robust results as were seen in the laboratory. The use of enhanced oil recovery in unconventional fields is an attractive prospect due to the large amount of original oil in place (OOIP). Because there are an estimated 167 billion to 900 billion barrels of OOIP in the Bakken Formation, recovering only 5 percent of that amount would equate to 8.4 billion to 45 billion barrels of oil.

Estimates based on modeling high- and low-case scenarios for the Bakken Formation for the 2017 through 2036 timeframe range from 254 million to 473 million barrels of incremental oil with direct state revenues of \$4.7 billion to \$7.4 billion. Capital investment cost to industry range from \$6.5 billion to \$7.7 billion and operating costs range from \$28.5 billion to \$39.2 billion during the same period. The total amount of CO₂ required is estimated at 233 million to 307 million metric tons. Cost associated with purchasing CO₂ account for approximately 30 percent of operating costs. Approximately 56 percent of the required CO₂ could be captured from sources in this state. The annual demand for CO₂ is expected to reach 35 million metric tons per year beginning in 2035.

The committee received information regarding the three main sources of CO₂, which include naturally occurring CO₂ fields, CO₂ captured from gas processing plants, and CO₂ captured from other industrial plants, such as power plants. Carbon dioxide from naturally occurring sources is the most prevalent source of CO₂ used in enhanced oil recovery projects due to the low cost of supply. Enhanced oil recovery projects are typically located within reasonable proximity to CO₂ sources due to the high costs of transporting CO₂. Three main areas where CO₂ enhanced oil recovery projects are occurring are in the Permian Basin, the Gulf Coast, and Wyoming. The Permian Basin projects source CO₂ from naturally occurring CO₂ fields in Colorado and New Mexico and from nearby gas processing plants, the Gulf Coast projects source CO₂ from the Jackson Dome CO₂ field and nearby industrial plants, and the Wyoming projects source CO₂ from two large gas processing plants.

The committee received testimony which indicated the estimated cost to capture CO₂ at power plants is \$115 per ton. If new technology brings the price to \$50 to \$60 per ton, it would narrow the gap between the price of CO₂ from power plants and the price of CO₂ from other industrial sources, which is currently at \$37 per ton. North Dakota potentially could source CO₂ from Wyoming for use in enhanced oil recovery projects if current CO₂ pipelines are extended into this state. The primary candidate for CO₂ sourced from within this state would be CO₂ derived from the Dakota Gasification Company once existing contracts for the company's CO₂ expire. There is potential for five of the state's coal-fired plants to invest in carbon capture technology, but the price to retrofit those plants would be approximately \$7.46 billion. The five retrofitted plants could capture 30 to 40 percent of CO₂ emissions, or 9.8 million tons of CO₂ per year. The objective of developing CO₂ capture technologies for power plants is to bring the price of capture down to \$30 per ton of CO₂.

The committee received information regarding the Petra Nova coal-fired plant in Texas, which is being retrofitted with carbon capture technology. Over \$1 billion has been invested in the plant and it is projected the cost to capture CO₂ at the Petra Nova plant will be \$50 per ton. The committee also received information regarding carbon capture technology at a plant in Saskatchewan.

The committee received information regarding federal programs that promote carbon capture and sequestration, including enhanced oil recovery tax credits, CO₂ sequestration credits, investment credits for advanced coal projects, and loan guarantees. Federal credits have had the largest impact on CO₂ enhanced oil recovery projects. Section 45Q of the Internal Revenue Code offers a \$10 credit for enhanced oil recovery and a \$20 credit for carbon capture and sequestration per ton of CO₂. The federal credit is available only for the first 75 million tons of CO₂. Fifty-three active capture technology projects are receiving funding from the United States Department of Energy, but many projects that receive federal funding end up losing the grants for failing to meet designated benchmarks.

The committee received information on the various state incentives and learned most states offer incentives relating to the capture of CO₂ from power plants for sequestration or use in enhanced oil recovery. The information suggested the extent to which the availability of state incentives have contributed to advancing CO₂ enhanced oil recovery is

questionable. Based on the current break-even prices determined under the study, no combination of incentives would be sufficient to make certain projects move forward.

The committee received various policy alternatives the state may wish to consider to encourage CO₂ enhanced oil recovery activities. One policy option would be to offer a deduction against oil extraction tax liability for CO₂ operating costs associated with enhanced oil recovery in the Bakken Formation and in conventional fields. The study considered \$5 and \$10 credits per ton of CO₂ for enhanced oil recovery in both the Bakken Formation and in conventional fields. A 50 percent reduction in oil extraction tax and gross production tax also was considered. The committee was informed these policy options would be in lieu of the current 5-year and 10-year oil extraction tax exemptions for tertiary recovery projects. Policy options that would be in addition to existing incentives include a 50 percent reduction in gross production tax and a \$400,000 credit against oil extraction tax liability per injector well, but would only apply to conventional wells. State policy options most comparable to the federal credit would be the \$10 per ton credit against oil extraction tax liability or a deduction for CO₂ operating costs. The committee was informed the deduction for operating costs might be more difficult to administer. The committee also reviewed information regarding how incentive options would translate when using other types of gasses for enhanced oil recovery.

Based on the study results, the consultant's recommendations were for the state to encourage research and development activities to determine the technological and commercial feasibility of CO₂ enhanced oil recovery, especially in the Bakken Formation. Funding from the state or federal government to run more pilot projects in the Bakken Formation also might encourage companies to invest and form joint public and private partnerships. The state could consider incentivizing the development of CO₂ capture technology, which would carry the added benefit of improving the environment. Income tax reductions also could be considered to encourage power plants to invest in carbon capture technology. Testimony indicated enacting tax incentives sends a message to industry that the state is willing to encourage investment in new technologies. However, a combination of factors, including higher oil prices, increased technology, and a more abundant and affordable supply of CO₂ would need to come together before enhanced oil recovery would be successful in North Dakota.

Testimony and Committee Considerations

Enhanced Oil and Gas Recovery Methods

The committee received information from a representative of the Department of Mineral Resources, regarding primary, secondary, and tertiary phases of oil production and various recovery methods. Ninety-five percent of the production in this state is primary production that uses a reservoir's natural pressure for recovery. Approximately 15 percent of the total OOIP in a conventional reservoir can be recovered using primary recovery methods. An additional 15 percent of the OOIP in a conventional reservoir can be recovered using secondary recovery methods and an additional 10 percent can be recovered using tertiary recovery methods. In an unconventional reservoir, such as the Bakken Formation, primary recovery methods will yield about 3 to 5 percent of the OOIP. It is unknown which types of secondary and tertiary recovery methods will prove successful in the Bakken Formation. Because the Bakken Formation contains over 300 billion barrels of OOIP, development of an enhanced recovery method that could increase recovery by 1 percent would yield 3 billion barrels of oil.

The committee received information regarding secondary recovery methods in conventional reservoirs and in the Bakken Formation. Water flooding increases the pressure in a reservoir, and there are 71 active water floods in the state, nearly all of which have been commenced within the last 20 years. Water flooding involves large capital expenditures because the number of required wells typically double and producers also have to contend with transportation costs and cost related to pressurizing and injecting water into the reservoir. Only three water flooding projects have been attempted in the Bakken Formation, all of which have been unsuccessful.

The committee received testimony regarding recovery using high-pressure air injection. Air injection is costlier than water flooding because it requires twice as many well bores and large air compressors. Air injection also yields lower recovery rates than water flooding and may contaminate a reservoir's natural gas stream to the point at which it can no longer be sold. The committee was informed only one horizontal fire flood has been attempted in this state. Because the producer must start the fire flood without exploding wells in the process, the use of fire flooding is a difficult maneuver.

Recovery using rich gas injection entails injecting produced gas back into a well. Rich gas injection is practiced in Alaska and can recover almost as much oil as CO₂ injection. Only two rich gas injection projects have been attempted in this state and both were discontinued because the operators found more economical recovery methods. The Department of Mineral Resources has approved one permit for a company to test rich gas injection in the Bakken Formation and the test will be the best field test available to determine whether CO₂ injection in the Bakken Formation would be a feasible method of recovery. The committee was informed producers are flaring 18 percent of all gas produced in the Bakken Formation.

The committee received information from representatives of the EERC regarding the potential for enhanced recovery using CO₂. The EERC has identified approximately 20 oil fields in the state with the potential for enhanced recovery using CO₂. The EERC has effectively extracted 100 percent of the oil from rock samples from the Bakken and Three Forks Formations and 75 to 85 percent of the oil from shales in a laboratory setting. The estimated amount of incremental production from unconventional reservoirs in this state is roughly 300 billion to 900 billion barrels of oil. The EERC is working on solutions for using CO₂ for enhanced recovery.

The committee was informed it is not necessary to employ water flooding prior to using CO₂. Reservoirs in Texas have transitioned directly from primary recovery to recovery methods using CO₂. Recovery using CO₂ is substantially more expensive than recovery using water flooding. Recovery using CO₂ requires twice the operating costs and twice the investment costs as recovery using water flooding. Unlike a primary recovery project, an operator will not postpone a CO₂ recovery project in a low-price environment because once a CO₂ recovery project is commenced, it cannot be ceased without causing damage to the reservoir. The testimony indicated it is important to consider the upfront investment costs, and the amount of time it will take a producer to recover those costs, when considering tax incentives for various production methods. According to information presented, North Dakota lacks the amount of CO₂ necessary for enhanced oil recovery.

The committee also received information regarding reservoir protection and the prevention of waste. The committee reviewed the definition of waste as provided in the Interstate Oil and Gas Compact Commission's 2004 Model Oil and Gas Conservation Act and regulations in place in Texas and Oklahoma to prevent waste.

Federal Clean Power Plan Implications

The committee's discussions were influenced by recent developments pertaining to the federal Environmental Protection Agency's (EPA) Clean Power Plan which aims to reduce CO₂ emissions nationally by 32 percent by the year 2030 as compared to 2005 emissions. The committee received information from a representative of the Attorney General's office regarding the status of legal action pertaining to the EPA's regulation of CO₂ emissions. The EPA conducted a series of rulemaking actions over the last several years to regulate CO₂ emissions for new and existing power plants pursuant to the Clean Air Act. Section 111(b) of the Clean Air Act pertains to emissions from new, modified, or reconstructed power plants and Section 111(d) of the Clean Air Act, commonly referred to as the Clean Power Plan, pertains to emissions from existing power plants. The EPA issued proposed rules, beginning as early as March 2012, pertaining to Sections 111(b) and 111(d) and issued final rules in October 2015.

The committee was informed North Dakota went from having one of the least stringent emission reduction goals under the proposed rules to one of the most stringent emission reduction goals under the final rules. Under a rate-based calculation, using pounds of CO₂ emitted per megawatt hour of electricity produced, North Dakota's required reductions increased from a 24.7 percent required reduction under the proposed rules to a 44.9 percent required reduction under the final rules. Multiple states filed petitions for review in opposition to the 111(d) rule, which were consolidated into the case of *West Virginia v. EPA*, and the 111(b) rule, which were consolidated into the case of *North Dakota v. EPA*. Various parties also intervened in support of the EPA, including environmental groups, public health organizations, power companies, and several states. Multiple states also filed motions to stay implementation of the 111(d) rule while litigation is pending because a tremendous amount of state resources would need to be dedicated toward preparing to comply with the rule's requirements. The motion to stay was granted, thus alleviating North Dakota's requirement to submit a final plan for compliance with the rule, or an initial draft of the plan with an extension request, by September 2016.

The committee received testimony from a representative of the State Department of Health which indicated the department is the state agency tasked with implementing the requirements under the Clean Air Act. A state's plan to comply with the requirements of the Clean Air Act must be enforceable at the state and federal level, and if a state chooses not to develop its own plan, a federal plan may be imposed in its place. The testimony indicated the state could see substantial impacts as a result of the final rules, including increased electricity prices due to the drastic CO₂ emission reductions required under the rules. The state had been making substantial reductions in emissions, reducing emission levels by 11 percent by 2014 as compared to 2005 emission levels despite increased load growth resulting from increased activity in the Bakken Formation.

The testimony suggested the new rules would force the State Department of Health to consider additional factors, such as conservation efforts and alternative energy generation sources when formulating a state plan for compliance. The department has hosted several meetings across the state to receive public input on the rule, and concerns expressed at the public meetings included concerns regarding the potential impact of the rule on jobs and the state's energy industry. Fifty-five percent of the electricity generated in North Dakota is transferred to other states and much of that energy is generated by coal-fired sources. If the rule results in the closure of coal plants, the residents of the state potentially could see a 40 percent increase in energy costs. Testimony indicated it is important for the state to look at an energy policy that addresses CO₂ emissions over the long term. It was argued technology supporting carbon capture and sequestration should be pursued considering the state's 800-year supply of minable coal.

The committee received testimony pertaining to the Clean Power Plan from a representative of the Lignite Energy Council. The Lignite Energy Council has yet to identify a compliance solution that would not involve closing coal plants if the rules under the Clean Power Plan remain unchanged. The option of applying post-combustion capture technology to existing plants would be extremely costly and would need to be applied to all power plants in the state operating at more than 450 megawatts and capture 90 percent of emissions to comply with the EPA's goals by 2030. The cost to apply comparable technology to a 150 megawatt plant in Canada was roughly \$600 million and the plant has experienced complications with the technology operating on a reliable basis. An alternative option would be for the state to build an additional 6,000 megawatts of wind-powered generation to build enough CO₂ credits to allow the state's coal-fired plants to continue to operate. The state only received credit for renewables installed after 2012 and as a result of the recent wind build-up in the state, many of the prime spots for wind generation already have been used. Difficulties also would arise in incorporating any additional wind energy into the state's electrical grid.

The committee received information from a representative of Basin Electric Power Cooperative to gain a better understanding of the changes that would need to be made to comply with the requirements under the Clean Power Plan. The company would need to add 1,350 megawatts of new wind-powered capacity, in addition to the 500 megawatts for which the company has already contracted, and 1,740 megawatts of new natural-gas-fired capacity. Incorporating this level of additional capacity would require over 500,000 acres of land for wind farms and associated facilities and, assuming a 100 percent success rate, would require 15 nearly simultaneous permitting processes and major projects. Over 1,000 substantial pieces of equipment would need to be purchased and over \$5 billion expended in project costs to meet the EPA's stated goals for 2022.

Committee members expressed concerns that the direction of the study may need to shift more heavily toward incentivizing the use of CO₂ for enhanced recovery in light of the requirements the state must meet under the Clean Power Plan.

Carbon Dioxide Resources

The committee received testimony from a representative of the EERC which indicated the United States Department of Energy estimates there are 137 billion barrels of recoverable oil that could be obtained in the United States using CO₂ enhanced oil recovery. The total amount of oil produced using CO₂ enhanced recovery is approximately 350,000 barrels per day with the majority of production coming from west Texas and smaller amounts coming from Wyoming, Montana, Mississippi, and Louisiana. North Dakota power plants emit over 30 million tons of CO₂ per year, which is almost the precise amount needed for a full build out of the Bakken Formation. The state does not have any natural sources of CO₂.

Representatives of IHS Energy testified the limited supply of CO₂ would be the biggest obstacle to using CO₂ for enhanced oil recovery. Companies will not undertake an enhanced oil recovery project unless they have secured a relatively economical source of CO₂. Enhanced oil recovery has been successful in the Permian Basin because there are natural sources of CO₂ in close proximity to oil fields. The majority of CO₂ enhanced recovery projects are full-cycle projects in which one company takes on the entire process, from capture to injection. Acquiring CO₂ from sources in southwest Wyoming also would be less costly than capturing CO₂ from smokestacks considering a capture cost of \$3 to \$4 per thousand cubic feet. Advances in technology would be required to reduce retrofit costs.

The committee received information from a representative of Basin Electric Power Cooperative regarding an overview of the operations of the Dakota Gasification Company's Great Plains Synfuels Plant. The Great Plains Synfuels Plant has been capturing CO₂ since 2000, and captures roughly 3 million tons of CO₂ per year. The plant transports captured CO₂ along a 205-mile pipeline for sequestration in Canada. Strategically placed taps are positioned along the pipeline which could be used to supply CO₂ to Williston Basin oil fields should CO₂ enhanced oil recovery begin to be used in North Dakota. The company delivered its 30 millionth metric ton of CO₂ to Saskatchewan for use in enhanced oil recovery in February 2015. The plant operates as a closed system and captures any plant emissions for further separation into various byproducts. The system can be contrasted with a typical power plant, such as the Antelope Valley Plant, where coal is pulverized, sprayed into a boiler, burned, and then CO₂ is emitted into the atmosphere. The testimony indicated the plant does not capture enough CO₂ for use in enhanced oil recovery in this state even after diverting the CO₂ being sent to Canada. Hundreds of millions of dollars would need to be invested for the plant to capture increased amounts of CO₂.

The committee received information from representatives of Denbury Resources, Inc., pertaining to an overview of the company's operations and any plans for the company's future expansion in this state. The company owns two CO₂ supply sources and operates over 1,100 miles of CO₂ pipelines. The company secures CO₂ from both manmade and natural sources and transports CO₂ in a liquid state at high pressure. Denbury's operations were producing approximately 74,000 barrels of oil per day during the first quarter of 2015, 41,000 barrels of which were produced using CO₂ enhanced recovery. The company's dealings in North Dakota began in March 2010 with the acquisition of Encore Acquisition Company. The acquisition included roughly 300,000 acres of the Bakken Formation, the Cedar Creek

Anticline field, the Bell Creek field in Montana, and several other smaller oil fields. The company has invested roughly \$1.18 billion in the state since December 2014 and is planning to extend its Greencore Pipeline to the Cedar Creek Anticline. Denbury estimates the Cedar Creek Anticline contains roughly 260 million to 290 million barrels of recoverable oil using CO₂ enhanced recovery.

The testimony indicated Denbury's business model is very capital intensive and the majority of the company's capital investments are made before any oil is produced. The cost to construct the 15-mile pipeline required to transport CO₂ to Denbury's fields in North Dakota would be approximately \$30 million. In addition a field's existing flow lines and injection lines typically need to be replaced to handle the corrosive qualities of liquefied CO₂. Separation plants also would need to be constructed to remove CO₂ from recovered production so the CO₂ can be reinjected in the reservoir. Denbury would need to invest approximately \$550 million to bring CO₂ enhanced oil recovery to North Dakota. The company would pipe CO₂ into North Dakota from outside sources for use in enhanced recovery in this state. The committee was informed the company would consider using other sources of CO₂ as those sources became available. Denbury plans to continue to bring CO₂ to the Cedar Hills Anticline, but the decision to go forward with a CO₂ enhanced recovery project in North Dakota depends on a variety of factors, including the price of oil, the state's tax environment, and opportunities that may arise elsewhere.

Committee members noted the information received by Denbury highlights the importance of providing certainty in tax policy. Committee members also generally agreed that when making changes to tax policy, policymakers must be aware of the message sent to companies that have invested, or are planning to invest, substantial funds in the state.

Emerging Technologies

Committee members noted the economics associated with obtaining enough CO₂ for enhanced recovery seems to be the driving factor in a company's decisionmaking process and there seems to be uncertainty regarding the success of enhanced oil recovery projects. The committee received information from the EERC indicating the EERC has worked on over 20 retrofit technologies and a large amount of energy has been aimed at making carbon capture technology technically and economically viable. The committee also received information regarding additional emerging technologies related to CO₂.

The committee received information from a representative of the Lignite Energy Council regarding the Allam Cycle project. The Allam Cycle technology is one of the potential solutions for new power plants in complying with CO₂ emission reduction requirements. The Allam Cycle is an alternative means of producing power which gasifies lignite coal and uses supercritical CO₂ rather than steam to spin turbines and generate electricity. The Lignite Research Council has provided funding to explore this technology and the Lignite Energy Council has been working with the EERC to further develop and test the Allam Cycle. The testimony contended supportive tax policy regarding the development of the Allam Cycle would make the project easier for utilities to fund and easier for the investment community to support. The cost of electricity produced using the Allam Cycle would be competitive with electricity produced using natural gas and would provide long-term price stability for consumers. Approximately one-third of the estimated load growth over the next 20 to 30 years potentially could be met with power generated using the Allam Cycle. Plants using the Allam Cycle could use the same fuel source as existing coal-fired plants and be located at the same plant site because they are so compact. The committee learned the main obstacle encountered when trying to gasify lignite, compress it, and then use supercritical CO₂ as a working fluid is corrosion. Industry representatives will be traveling to Texas in late 2016 to tour an Allam Cycle project and assess the progress being made with the new technology.

A representative of the Lignite Energy Council provided information regarding the Kemper County Energy Facility in Mississippi which is equipped with the best technology available for CO₂ capture and storage. The facility captures and stores CO₂ from coal combusted within the facility. The facility cost over \$6 billion to construct, which was more than \$3 billion over the initial budget estimates; however, the technology implemented in the facility is working as expected. The facility has been producing electricity using natural gas as a feedstock for almost a year and will ultimately produce synthetic natural gas from lignite and use that gas as a fuel to power turbines to produce electricity. This type of facility, though expensive to develop at the outset, provides price certainty over the long term. The Kemper County Energy Facility was expected to be running exclusively on lignite by February 2016, and CO₂ produced from the plant will be captured and shipped to neighboring oil fields for use in enhanced oil recovery. The facility is employing the same concepts as Dakota Gasification Company's Great Plains Synfuels Plant except on a much larger scale.

Existing Incentives Related to Enhanced Recovery

The committee received information regarding tax incentives associated with enhanced recovery of oil and gas and the usage and fiscal impact of each incentive. The committee received information on the following incentives:

- Oil extraction tax exemptions for incremental production from a secondary or tertiary recovery project;
- A sales and use tax exemption for materials incorporated into specified CO₂ systems for use in enhanced oil recovery;

- A sales and use tax exemption for CO₂ used for enhanced oil recovery;
- A sales and use tax exemption for environmental upgrade materials used in power plants and processing plants;
- Carbon dioxide capture system exemptions from ad valorem and coal conversion facilities privilege tax;
- Property tax exemptions for pipeline property and associated transportation and storage equipment used for CO₂ enhanced oil recovery; and
- A coal conversion facilities privilege tax credit for the capture of CO₂ emission.

The committee received testimony from a representative of the Dakota Gasification Company which indicated the company claimed \$1.9 million in CO₂ capture credits in 2015. The CO₂ capture credit provides a credit against the coal conversion facilities privilege tax for achieving a 20 percent capture of CO₂ emissions. The credit was enacted in 2009 and is equal to a 20 percent reduction in the general fund share of the coal conversion facilities privilege tax imposed during the taxable period. An additional 1 percent reduction in the general fund share of the tax is allowed for every additional 2 percentage points of CO₂ emission capture, up to a 50 percent reduction for 80 percent or more capture. The operator of a coal conversion facility is required to report to the Legislative Council on an annual basis regarding certain aspects of the CO₂ capture project. The credit expires in 2019.

Proposed Incentives

The committee received testimony from a representative of the EmPower ND Commission regarding the commission's policy recommendations relating to the committee's study of enhanced recovery. The commission provided the following three recommendations, which also were provided to the interim Energy Development and Transmission Committee:

- Provision of incentives for the capture and use of CO₂;
- Investment in foundational research relating to the state's energy resources; and
- Investment in research and development for large-scale commercialization opportunities, such as the Allam Cycle.

The committee was informed the EmPower ND Commission discussed the potential for an incentive for CO₂ enhanced oil recovery which would be capped based on a certain amount of CO₂ used or a certain number of barrels of oil recovered. The idea behind the incentive would be to reward early actors for taking a risk in developing CO₂ capture technology and CO₂ enhanced oil recovery technology. Placing a limit on the tons of CO₂ used or barrels of oil recovered would give the state certainty regarding the cost of the incentive.

Taking into account testimony received and incentive options provided by IHS Energy, the committee considered a bill draft that would have provided for a \$10 credit against oil extraction tax for each ton of CO₂ purchased or acquired for use in enhanced oil recovery in this state. The bill draft would have required oil producers to report to the Industrial Commission the amount of CO₂ initially injected into an oil reservoir in this state and would have required the Industrial Commission to certify those amounts to the Tax Commissioner. If a purchaser of oil, rather than the producer of oil, was filing and paying the tax, the bill draft would have required the purchaser to include documentation provided by the producer verifying the amount of the producer's credit to be deducted from the tax due. Information provided by the Tax Department indicated the fiscal impact of the credit would be negligible for the upcoming biennium, but would be difficult to project for future periods. The bill draft also would require the Tax Department to modify certain reporting forms to apply the credits and make database changes to effectively process the credits.

The committee received comments from a representative of the Lignite Energy Council indicating the Lignite Energy Council supported the goals of the committee, but the concepts in the bill draft may need to be refined further in light of recent developments.

Industry representatives and a group of legislators took part in a tour of facilities in Texas which demonstrated an alternative balance of incentives may better address the goals of the study and market conditions and advancements in technology are not to the point at which the state's supply of CO₂ could be monetized to the degree of necessitating the bill draft the committee was considering. Testimony indicated a \$10 per ton credit would not be enough to spur industry to undertake the \$800 million of infrastructure costs associated with capturing CO₂ emissions. Other factors, including large federal and industrial investments, would be needed to bridge the gap in making projects economically feasible. Industry also would need reassurance the price of oil would remain high enough for projects to remain economically feasible.

The committee received comments from a representative of Basin Electric Power Cooperative who agreed the structure of the proposed incentive could benefit from modifications regarding the proposed beneficiaries. Industry, state, and federal resources likely would need to come together to make CO₂ capture projects work because it would cost

roughly \$50 million to \$70 million per ton of CO₂ captured to place the necessary capture equipment on power plants. Advances in CO₂ capture and the use of CO₂ for enhanced recovery also need to be made before the economics of CO₂ enhanced oil recovery would make sense for oil producers. Additional research is being conducted to determine the amount of CO₂ that could be used in conventional wells and the amount of CO₂ that could be captured from coal-fired plants in this state. The committee received a recommendation that the issue be further studied during the 2017-18 interim at which time discussion of a bill draft focusing on where these two amounts coincide would be ripe for discussion. It was suggested developments expected to occur throughout 2017 also would lead to a more informed discussion during the 2017-18 interim.

Committee members participating in the tour in Texas agreed the solution to achieving enhanced oil recovery lies in incentivizing both the producers and users of CO₂. Additional committee members expressed similar sentiments regarding the need to shift the placement of incentives and to focus on additional research to bring about advancements in technology.

Distribution of Revenue and Research Funding

In considering potential funding sources for research relating to CO₂ capture and enhanced oil recovery, the committee received information regarding the revenue generated by the oil extraction tax, gross production tax, coal severance tax, and coal conversion tax and reviewed the funds to which the revenue is distributed and the estimated revenue distributions for the 2015-17 biennium as of October 2016. The committee also received information from the State Treasurer regarding past distributions of coal conversion facilities privilege tax and coal severance tax revenues to political subdivisions and information from a representative of the Tax Department regarding historical collection data pertaining to both taxes.

The committee reviewed information pertaining to the lignite research fund and received information from a representative of the Industrial Commission regarding the oil and gas research fund. The Industrial Commission oversees the Oil and Gas Research Program, which is funded by a percentage of the state's share of oil and gas gross production tax and oil extraction tax revenues. Every dollar awarded from the oil and gas research fund must be matched dollar-for-dollar with other funds. The committee received information regarding six ongoing contracts between the Oil and Gas Research Program and the EERC. The funding for the Bakken CO₂ Storage and Enhanced Oil Recovery Program has totaled over \$2.5 million, with the majority of the funding provided by the United States Department of Energy. The purposes of the Bakken CO₂ Storage and Enhanced Oil Recovery Program is to develop improved tools and techniques to evaluate fluid flow in tight rocks to determine the potential for enhanced oil recovery in the Bakken using CO₂. Reduced oil prices are not expected to impact funding for the Oil and Gas Research Program because the program is one of the first items funded with oil and gas gross production tax and oil extraction tax revenues.

The committee considered other sources of revenue that potentially could be directed toward funding continued research and committee members generally agreed additional investments in research and development may be required to move the potential for CO₂ capture and enhanced oil recovery forward.

Conclusions

The committee makes no recommendations with respect to its studies of enhanced oil recovery.

Reports

Oil and Gas Gross Production Tax Allocation Reports

The committee was assigned the responsibility to receive an annual report from the Tax Commissioner from compiled reports from counties and school districts receiving allocations of oil and gas gross production tax revenues describing funds received, expended, and unexpended. The report pertaining to allocations received by counties is required to be provided to the Legislative Council within 45 days after the end of each calendar year pursuant to Section 57-51-15(6). The report indicated a total of \$132,532,965 was received by the 16 counties receiving oil and gas gross production tax distributions in calendar year 2015. The Tax Department sent revenue and expenditure reporting forms to each county that received oil and gas gross production tax distributions. All counties receiving distributions, with the exception of Ward County, responded to the request for information.

The report pertaining to allocations received by school districts is required to be provided to the Legislative Council within 45 days after the end of each fiscal year pursuant to Section 57-51-15(7). The report indicated a total of \$32,544,135 was received by the 60 school districts receiving oil and gas gross production tax distributions in fiscal year 2016. Fiscal year 2016 is the first year the reporting requirement has been in place for school districts, and the Tax Department used surveys and worked in cooperation with the Department of Public Instruction to gather the required information. The Tax Department sent revenue and expenditure reporting forms to each school district that received oil and gas gross production tax distributions. Thirteen school districts did not respond to the request for information.

Committee members expressed frustration that county and school district officials seemed to be disregarding statutory reporting requirements. Committee members contended the reporting requirements were in place for a reason and parties responsible for providing information should take the reporting requirements more seriously. The committee was informed there are no penalties to address instances in which responsible parties fail to provide the required information to the Tax Department.

State Grantor Reports for Incentives

The committee was assigned the responsibility to receive a compilation and summary of state grantor reports filed annually by the Department of Commerce and the reports of state agencies that award business incentives for the previous calendar year, pursuant to Section 54-60.1-07. According to the report, a business must enter a business incentive agreement with a grantor before the business may receive an incentive. Business incentive agreements must contain a description of the incentive to be granted as well as the job goals the business seeks to achieve within the first 2 years. A recipient business must report on progress toward achieving stated goals until the goals are met. The report indicated for the period of 2011 through 2015, 748 business incentive accountability agreements were entered, totaling an incentive value of \$107,229,806. The report detailed the distribution of business incentives by type, public purpose, and type of business. The report also provided the number of agreements entered per year and identified whether the goal was to create jobs, retain jobs, or neither. Seventy-three percent of projects met stated job creation and retention goals within the first 2 years.