ELECTRIC INDUSTRY COMPETITION COMMITTEE

The Electric Industry Competition Committee is created by North Dakota Century Code (NDCC) Sections 54-35-18 through 54-35-18.3 with the duty to study the impact of competition on the generation, transmission, and distribution of electric energy within this state. In addition, the Legislative Council delegated to the Electric Industry Competition Committee the duty of receiving three reports. Under Section 57-40.6-11, the Division of State Radio is required to report annually to the Legislative Council on the operation of and any recommended changes in the emergency 911 telephone system standards and guidelines. Under Section 57-40.6-12, the Public Safety Answering Points Coordinating Committee is required to provide by November 1 of each even-numbered year to the Legislative Council a report on city and county fees on telephone exchange access service and wireless service. Under Section 49-24-13, the North Dakota Transmission Authority is required to provide a written report to the Legislative Council on its activities each biennium.

North Dakota Century Code Section 54-35-18.2 outlines the study areas that the committee is to address in carrying out its statutory responsibilities. This section provides that the committee is to study the state's electric industry competition and electric suppliers and financial issues, legal issues, social issues, and issues related to system planning, operation, and reliability and is to identify and review potential market structures.

Senate Bill No. 2015 (2003) extended the expiration date of the Electric Industry Competition Committee from August 1, 2003, to August 1, 2007. The bill also expanded membership of the committee to six members of the House of Representatives, four of whom must be from the majority political party and two of whom must be from the minority political party, and six members of the Senate, four of whom must be from the majority political party and two of whom must be from the minority political party.

Committee members were Representatives Merle Boucher (Chairman), Wesley R. Belter, Tracy Boe, Michael D. Brandenburg, David Drovdal, and George J. Keiser and Senators Robert S. Eberle, Tim Mathern, Duane Mutch, Larry J. Robinson, John O. Syverson, and Ben Tollefson.

The committee submitted this report to the Legislative Council at the biennial meeting of the Council in November 2006. The Council accepted the report for submission to the 60th Legislative Assembly.

ELECTRIC INDUSTRY RESTRUCTURING

Background

North Dakota Century Code Section 54-35-18 states that the Legislative Assembly finds that the economy of North Dakota depends on the availability of reliable, low-cost electric energy and that there is a national trend toward competition in the generation, transmission, and distribution of electric energy, and the Legislative Assembly acknowledges this competition has both potential benefits and adverse impacts on the state's electric suppliers as well as on their shareholders and customers and citizens of this state. The legislation establishing the committee reflected the Legislative Assembly's concern that the electric industry is changing rapidly and if competition is to be introduced into North Dakota, it should be done in a fair and equitable manner. In 1997 builders of new technology generating plants, the natural gas industry, and states with high electric rates or excess generating capacity were promoting electric industry restructuring. Arguments put forward for restructuring or implementing competition in the electric industry include greater customer choice and the possibility that open competition may lower costs and encourage generating efficiency. However, risks and challenges of retail competition include maintaining reliability of supply, pricing outcomes in which some customers may benefit at the expense of others, and allocating stranded costs. The impetus for electric industry restructuring also has come from large industrial and commercial energy users that are opposed to subsidizing residential electricity users.

Under the current industry structure, electricity is provided to retail customers by utilities that have geographic monopolies on the provision of electric service within their service territories. Traditionally, an electricity customer must purchase electric services from the utility serving that customer's service territory, including the three primary services--generation, transmission, and distribution. Generation refers to the actual creation of electricity, which may be generated using a number of methods and fuel, including nuclear, coal, oil, natural gas, hydro, or wind. Transmission refers to the delivery of electricity over distances at high voltage from a generation facility through a transmission network usually to one or more distribution substations where the electricity is stepped down for distribution to residential, commercial, and industrial customers. For the retail customer, the costs for these functions are bundled into retail rates, along with the cost of distribution. Distribution involves the retail sale of electricity directly to consumers.

Other functions traditionally provided by vertically integrated utilities include customer service, billing, meter reading, demand-side management, research and development, and aggregation and ancillary services. Aggregation is the development and management of a power portfolio, combining power from a variety of sources to match the demand for power with an adequate power supply, and a portfolio of customers with combined demands to economically serve those customers. Ancillary services are those services necessary to effect a transfer of electricity between a seller and a buyer and to coordinate generation, transmission, and distribution functions to maintain power quality and system stability.

Under the current industry structure, the utility serving a service territory provides all these services and functions and sells them as a single bundle. Nationwide, the restructuring debate centers on whether or how the generation function should be separated from the bundle allowing retail customers to choose an electricity supplier. If generation is unbundled from transmission and distribution, these services may remain regulated functions.

Generally, three major types of electric utilities exist--investor-owned utilities, municipal and other government-owned utilities, and rural electric cooperatives. Generally, states regulate investor-owned utilities regarding their profits, operating practices, and pricing to end-use retail customers, while the Federal Energy Regulatory Commission (FERC) governs the pricing of wholesale bulk power sales and transmission services.

State Regulation

Subject to the limitations provided in NDCC Section 49-02-01.1, which provides that the Public Service Commission may not regulate government-owned and not-for-profit electric utilities, in North Dakota the Public Service Commission regulates electric utilities engaged in the generation and distribution of light, heat, or power. North Dakota Century Code Section 49-02-03 grants to the Public Service Commission the power to supervise and establish rates. This section provides:

> The commission shall supervise the rates of all public utilities. It shall have the power, after notice and hearing, to originate, establish, modify, adjust, promulgate, and enforce tariffs, rates, joint rates, and charges of all public utilities. Whenever the commission, after hearing, shall find any existing rates, tariffs, joint rates, or schedules unjust, unreasonable, insufficient, unjustly discriminatory, or otherwise in violation of any of the provisions of this title, the commission by order shall fix reasonable rates, joint rates, charges, or schedules to be followed in the future in lieu of those found to be unjust, unreasonable, insufficient, unjustly discriminatory, or otherwise in violation of any provision of law.

Concerning the Territorial Integrity Act, NDCC Section 49-03-01 provides that an electric public utility must obtain a certificate of public convenience and necessity from the Public Service Commission before constructing, operating, or extending a plant or system. Sections 49-03-01.1 through 49-03-01.5 require an electric public utility to obtain a certificate of public convenience and necessity before constructing, operating, or extending a public utility plant or system beyond or outside the corporate limits of any municipality. However, Section 49-03-01.3 exempts electric public utilities from the requirement to obtain a certificate of public convenience and necessity for an extension of electric distribution lines within the corporate limits of a municipality in which the public utility has lawfully commenced operations, provided the extension does not interfere with existing services provided by rural electric cooperatives or another electric public utility within the municipality and that any duplication of services is not deemed unreasonable by the Public Service Commission.

Federal Actions

In 1978 Congress enacted the Public Utility Regulatory Policy Act. The goals of this Act were to make the United States self-sufficient in energy, increase energy efficiency, and encourage the use of renewable alternative fuels. The Act required that utilities buy power from companies that were not utilities. The Act created a new industry of nonutility power generators.

In 1992 Congress enacted the Energy Policy Act to encourage the development of a competitive, national, wholesale electricity market with open access to transmission facilities owned by utilities to new wholesale buyers and new generators of power. The Act gave competitive generators access to the transmission grid at competitive rates and terms. In addition, the Act reduced the regulatory requirements for new nonutility generators and independent power producers. The Federal Energy Regulatory Commission initiated rulemaking to encourage competition for generation at the wholesale level by assuring that bulk power could be transmitted on existing lines at cost-based prices. Under this legislation and rulemaking, generators of electricity, whether utilities or private producers, could market power from underutilized facilities across state lines to other utilities.

The Federal Energy Regulatory Commission has taken a number of steps to encourage competition in the wholesale market. These actions include authorizing market-based rates, issuing Section 211 wheeling orders, ordering open-access transmission tariffs, and issuing the open-access transmission rule (FERC Order No. 888). Market-based rates are those set by willing buyers and sellers of power. This method may be used instead of the more traditional method of ratesetting by regulators pursuant to administrative hearings, with rates based on the cost of producing power. On April 24, 1996, FERC issued Order Nos. 888 and 889, which require all utilities that own, control, or operate transmission lines to file nondiscriminatory open-access transmission tariffs that offer competitors transmission service comparable to the service that the utility provides. In addition, FERC Order No. 888 recognizes the right of utilities to recover legitimate, prudent, and verifiable costs stranded by opening the wholesale electricity market, i.e., stranded costs. Finally, FERC Order No. 888 requires public utilities to unbundle their power and services for wholesale power transactions by requiring the internal separation of transmission from generation marketing services.

Other States

According to the *Status of State Electric Industry Restructuring Activity as of February 2003* prepared by the United States Department of Energy Information Administration, 24 states and the District of Columbia either have enacted enabling legislation or issued a regulatory order to implement retail access. Each local distribution company continues to provide transmission and distribution (delivery of energy) services. Retail access allows customers to choose their own supplier of generation energy services, but each state's retail access schedule varies according to the legislative mandate or regulatory orders.

Arizona, Connecticut, Delaware, District of Columbia, Illinois, Maine, Maryland, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Ohio, Oregon, Pennsylvania, Rhode Island, Texas, and Virginia either have enacted enabling legislation or issued a regulatory order to implement retail access. Retail access is either currently available to all or some customers or will soon be available. In Oregon no customers are participating in the state's retail-access program, but that state's laws allow nonresidential customers access. Alabama, Alaska, Colorado, Florida, Georgia, Hawaii, Idaho, Indiana, Iowa, Kansas, Kentucky, Louisiana, Minnesota, Mississippi, Missouri, Nebraska, North Carolina, North Dakota, South Carolina, South Dakota, Tennessee, Utah, Vermont, Washington, West Virginia, Wisconsin, and Wyoming are not actively pursuing restructuring. In West Virginia the legislature and Governor have not approved the Public Service Commission's restructuring plan authorized by state law. The legislature has not passed a resolution resolving the tax issues of the Public Service Commission plan, and no activity has occurred since early in 2001. Arkansas, Montana, Nevada, New Mexico, and Oklahoma have delayed their restructuring process or implementation of retail access. California has suspended direct retail access.

ENERGY ACT OF 2005

On August 8, 2005, the President signed into law the Domenici-Barton Energy Policy Act of 2005. The bill is 1,725 pages long, consists of 18 titles, and authorizes $85 billion in spending and tax incentives. The following are some of the provisions of the Act which relate to the generation, transmission, and distribution of electric energy which may have relevance in this state.

1. The Act authorizes funding and loan guarantees for "clean coal" technologies, such as coal gasification and advanced combustion technologies. Over the next 10 years, $5.23 billion is authorized in spending for clean coal technology. The Act creates a clean coal power initiative campaign that includes grants to universities to establish centers of excellence for energy systems of the future. The Act contemplates merit-based grants to institutions of higher education to be awarded to institutions with the greatest potential for advancing new clean coal technologies projects.
2. The Act establishes an independent organization to improve the reliability of the transmission grid to mandatory and enforceable standards. The Act replaces the North American Electric Reliability Council and 10 regional councils that are voluntary and operate independently without any FERC oversight with an Electric Reliability Organization with authority to enforce reliability standards and impose penalties.
3. The Act provides for new procedures for siting electric transmission lines, including federal preemption in some circumstances. The Act directs the Department of Energy Secretary to identify national interest electric transmission corridors. If a state commission does not approve a project or approve it with conditions that make construction economically or physically infeasible, FERC may issue construction permits for these new lines and condemn land by federal eminent domain. There is an exception for siting jurisdiction for states if there are three contiguous states that form a regional transmission siting agency. In this case, FERC may only act if those three states disagree with the regional transmission siting agency.
4. The Act provides FERC limited authority over nonregulated entities to ensure nondiscriminatory access to electric transmission lines.
5. The Act repeals the federal Public Utility Holding Company Act of 1935, which provided for Securities and Exchange Commission jurisdiction over public utility mergers and acquisitions. The Public Utility Holding Company Act prohibited acquisition of any wholesale or retail electric business through a holding company unless that business forms part of an integrated public utility system when combined with the utility's other electric business. The Public Utility Holding Company Act also restricted ownership of an electric business by a nonutility corporation.
6. The Act expands the Public Utility Regulatory Policies Act of 1978 to require state regulators to conduct an investigation and issue a decision on smart metering and demand responsive devices, net metering of bond-site generation, utility fuel source diversification, fossil fuel generation efficiency, and interconnection for distributed generation. In addition, the Act repeals on a prospective basis the obligation of an electric utility to buy electric energy from and sell electric energy to a qualifying facility under certain circumstances.
7. The Act authorizes FERC to require the posting of electricity and natural gas pricing information to provide price discovery and market transparency. In addition, manipulative or deceptive practices with the intent to manipulate market prices are prohibited.
8. The Act requires FERC to make rules implementing incentive pricing and allow recovery of prudently recovered costs necessary to comply with mandatory reliability standards and transmission infrastructure development.

PREVIOUS STUDIES

1967-68 Study

In 1967 the Legislative Assembly approved House Concurrent Resolution No. B-2 which requested a two-year study be made of the laws relating to certificates of public convenience and necessity for extensions of service by electric suppliers and the extensions of electric transmission and distribution lines of electric utilities. The resolution directed that a committee composed of three members of the House of Representatives and two members of the Senate meet during the succeeding biennium with two persons representing electric public utilities and two persons representing rural electric cooperatives to study what method, if any, should be provided to resolve territorial disputes between electrical suppliers, whether more lucrative market areas were essential to the efficiency of rural electric cooperatives, and if rural electric cooperatives should be regulated in the same manner as rural telephone cooperatives.

This committee received testimony from the Public Service Commission, rural electric cooperatives, and public utility companies. The public service commissioners were basically of the opinion that the Territorial Integrity Act was beneficial, and they pointed out some areas in which improvements could be made. The position of the rural electric cooperatives was that the Territorial Integrity Act was working and that fair and adequate guidelines were being developed by the Public Service Commission in following the interpretation placed on the law by the North Dakota Supreme Court in *Montana-Dakota Utilities Company v. Johanneson* 153 N.W.2d 414 (N.D. 1967). The cooperatives maintained any change in the law would result in considerable expense to cooperatives and public utility companies alike, as interpretive measures would have to begin anew. The position of the public utility companies was that the Territorial Integrity Act stifled growth and created confusion and uncertainty because the utilities are not allowed to expand with the population move from city and rural areas into the fringe locations around cities. The public utilities maintained that in order to serve their customers economically and to provide a return to their stockholders, they must also continue to grow, and the only area in which growth was possible was in the metropolitan fringe areas. The committee made no recommendation as a result of this study.

1997-98 Study

During the 1997-98 interim, the Electric Utilities Committee reviewed the history and operation of the Territorial Integrity Act. The committee received testimony from representatives of the state's investor-owned utilities and the state's rural electric cooperatives.

Representatives of Montana-Dakota Utilities Company testified that the Territorial Integrity Act is unfair in fostering effective electric competition in North Dakota. They argued that the Act is a barrier to giving customers throughout the state the ability to make economic energy choices and as such should be repealed and fairplay rules substituted in its place for all competitors. They testified if rural electric cooperatives wish to pursue loads in urban areas, in competition with public utilities, then rural electric cooperatives engaging in such activity should be subject to the same regulatory overview as public utilities, should not qualify for favorable financing arrangements with the federal government, should not be exempt from state and federal income taxes, should not have preferential access to low-priced federal power, and should not receive potential for debt forgiveness by the Rural Utilities Service. The committee received testimony from a representative of Otter Tail Power Company that the Territorial Integrity Act is not accomplishing what its stated objectives are--to efficiently allocate scarce resources and to minimize disputes between electric suppliers--because the Act leads to a wasteful duplication of electrical facilities and increases, rather than minimizes, the likelihood of disputes between electric suppliers.

Representatives of the state's rural electric cooperatives responded that the Territorial Integrity Act is working well and is serving the purposes for which it was enacted. They argued that the state's investor-owned utilities have exclusive territories within the state's municipalities the rural electric cooperatives cannot penetrate and that the Act avoids the costly duplication of utility infrastructure. They noted there is substantial undeveloped land within the service territories of the investor-owned utilities while there is an outmigration of population from the rural areas and a corresponding decline in electrical usage. If it were not for some larger industrial and commercial loads, and some growth around cities in areas that were previously rural, rural electric cooperatives would have experienced a substantial decline in their sales, and investor-owned utility territory should not be expanded at the expense of the rural electric cooperatives that have invested in rural North Dakota. Representatives of the rural electric cooperatives pointed out that since enactment of the Territorial Integrity Act, investor-owned utilities have continued to grow in customers and revenue and have not lost market share to rural electric cooperatives.

The committee made no recommendation as a result of this study.

1999-2000 Study

During the 1999-2000 interim, the Electric Industry Competition Committee studied statutes relating to the extension of electric lines and facilities and the provision of electric service by public utilities and rural electric cooperatives within and outside the corporate limits of a municipality and addressed the criteria used by the Public Service Commission under NDCC Chapter 49-03 in determining whether to grant a public utility a certificate of public convenience and necessity to extend its electric lines and facilities to serve customers outside the corporate limits of a municipality and the circumstances under which a rural electric cooperative may provide electric facilities and service to new customers and existing customers within municipalities being served by a public utility.

The Public Service Commission considers 10 issues or factors, either developed by the commission or taken from North Dakota Supreme Court decisions concerning the Territorial Integrity Act, in Territorial Integrity Act disputes:

1. From whom does the customer prefer electric service?

2. What electric suppliers are operating in the general area?
3. What electric supply lines exist within a two-mile radius of the location to be served, and when were they constructed?
4. What customers are served by electric suppliers within at least a two-mile radius of the location to be served?
5. What are the differences, if any, between the electric suppliers available to serve the area with respect to reliability of service?
6. Which of the available electric suppliers will be able to serve the location in question more economically and still earn an adequate return on its investment?
7. Which suppliers extended electric service would best serve orderly and economic development of electric service in the general area?
8. Would approval of the application result in wasteful duplication of investment or service?
9. Is it probable that the location in question will be included within the corporate limits of a municipality within the foreseeable future?
10. Will service by either of the electric suppliers in the area unreasonably interfere with the service or system of the other?

The committee made no recommendation as a result of this study.

2001-02 Study

During the 2001-02 interim, the Electric Industry Competition Committee again reviewed the history and operation of the Territorial Integrity Act.

Representatives of the North Dakota Association of Rural Electric Cooperatives advocated that the rural electric cooperative enabling law, NDCC Chapter 10-13, be amended to allow electric cooperatives an unlimited right to serve in urban areas and to make urban customers cooperative members, provided that the cooperative purchases or otherwise acquires electric facilities from another utility on a willing buyer-willing seller basis. Proponents argued that providing more options for local electric service, rather than fewer, support the idea that territorial integrity issues should be resolved through negotiation rather than legislation.

Representatives of the state's investor-owned utilities opposed the willing buyer-willing seller proposal submitted by the North Dakota Association of Rural Electric Cooperatives. They argued the proposal would allow electric cooperatives to purchase much larger investor-owned or municipally owned utility electric systems than allowed under current law, would encourage electric cooperatives to entice municipalities to acquire existing electric utilities from investor-owned utilities and resell the electric utilities to an electric cooperative, and would provide a substantial advantage to an electric cooperative in competing with investor-owned utilities for the purchase of other investor-owned or municipal-owned electric utilities because investor-owned utility rates are set based upon the net book value of the investment rate base and the Public Service Commission generally will not allow an acquisition premium in an investor-owned utility's rate base.

The committee made no recommendation as a result of this study.

2003-04 Study

During the 2003-04 interim, the Electric Industry Competition Committee again reviewed the Territorial Integrity Act. In addition, the Legislative Council assigned to the committee the study directed by House Concurrent Resolution No. 3061--the feasibility and desirability of enacting legislation to tax electric utility providers with a fair and uniform tax system. The Legislative Council also assigned to the committee a study directed by Section 1 of Senate Bill No. 2310--issues related to wind energy development in this state.

Taxation

Electric industry taxation depends upon how an electric utility conducts business. Separate forms of taxation apply to severance of coal from the earth, generation of electricity or production of other products from coal, generation of electricity from wind, transmission of electricity through large capacity transmission lines, and distribution of electricity to consumers. The committee reviewed coal severance taxes, coal conversion taxes, property taxes, gross receipts taxes, transmission line taxes, city privilege taxes, and municipal utility revenues.

The committee considered, but did not recommend, a bill draft relating to the taxation of generation, transmission, and distribution of electric power. The bill draft is compared to present law in the following table:

Property	Present Law	Allocation	2003-04 Bill Draft
Coal severance	37.5 cents/ton 2 cents/ton	30% coal fund 70% coal-producing counties • 30% to cities • 30% to school districts • 40% to counties Lignite research fund	No change
Coal conversion in lieu of property tax on facility	For electricity generating with 10,000 kilowatt capacity .65 mill x 60% installed capacity x hours taxable period + .25 mill/kilowatt-hour of electricity produced For coal gasification - Higher of 4.1% of gross receipts or 13.5 cents/1,000 ft^3 of gas produced	15% to producing county 85% state general fund Through 2009, first $41,666.67 from .25 mill/kilowatt-hour from sale in state general fund	Expand to noncoal plants of 5 megawatts or more

Property	Present Law	Allocation	2003-04 Bill Draft
Property tax	Investor-owned All operative property is centrally assessed unless transmission line after September 30, 2002 Rural electric cooperatives exempt except for land	To counties based on property in county	Removed
Gross receipts	• Rural electric cooperatives • 2% on transmission and distribution cooperatives • 2% on generation cooperatives unless subject to coal conversion taxes then exempt	To counties based on mile of line First 2 years to county with generating facility Third and subsequent years • First $50,000 to county • Second $50,000 to county and state general fund remaining 25% to county and 75% to state general fund	Removed
Transmission line voltage of 41.6 kilovolts or more	Rural electric cooperatives $225/mile for lines 230 kilovolts or larger $300/mile for rural electric cooperatives and investor-owned utilities for line in service after September 30, 2002	To counties based on miles of line	Removed for rural electric cooperatives
City privilege			Removed for rural electric cooperatives
Transmission facilities			• Less than 50 kilovolts - $75/mile • 50 to 99 kilovolts - $150/mile • 100 to 199 kilovolts - $300/mile • 200 to 299 kilovolts - $450/mile • 300 to 399 kilovolts - $600/mile • 400 kilovolts or more - $900/mile
Distribution tax		To county of retail sale then proportionally to levies to taxing districts	52 cents/megawatt-hour
Retail sales		To counties based on miles of line then proportionally to levies to taxing districts	.88% of revenue on retail sales

Proponents of the proposal presented several reasons to support the proposed bill draft. First, the in lieu taxes would have been uniform for all investor-owned utilities and rural electric cooperatives so it was argued the proposal met the test of fairness. Second, proponents said the proposal would have minimized tax shifting between rural electric cooperatives and investor-owned utilities. Although individual utilities might have paid more or less in taxes, overall the tax shift between investor-owned utilities and rural electric cooperatives would have been only 1.5 percent. Third, it was argued the tax formulas would have been easy to calculate and administer. Fourth, proponents said the in lieu taxes would have been predictable, which led to the final benefit which would have been that the proposal guaranteed that overall the plan would raise approximately the same amount of revenue for local taxing districts as the current taxation system of ad valorem and gross receipts taxes that would be replaced. In addition, if the electric industry grows, political subdivisions would have seen increased tax revenues in future years.

Opponents of the proposal presented several reasons to oppose the proposed bill draft. First, they said property taxes should be taxes on the value of property, not an "in lieu of" system that is confusing and contains opportunity for mischief by shifting taxes from one property owner to another. Second, opponents said the proposal violated the concept of simplicity and easy understandability and that a tax on transmission lines, but not including substations, appeared to be an effort to achieve a predetermined effect, i.e., a minimalization of tax increases for the large voltage transmission lines. Third, it was argued the proposal would have imposed an administrative burden on investor-owned combination utility companies, such as Montana-Dakota Utilities Company, because it would have subjected their property to two different tax systems--one for electric operations and one for natural gas operations.

The committee considered, but did not recommend, a bill draft that would have eliminated gross receipts taxes for rural electric cooperatives and would have subjected their property to centrally assessed ad valorem property taxes. Proponents of this proposal presented a primary reason to support the proposed bill draft, that rural electric cooperative property would be taxed in exactly the same manner in which investor-owned property is taxed. Because the central assessment method is a well-developed system for determining value for investor-owned property, it was argued an appropriate methodology could be developed to extend this method to rural electric cooperative property, even if some of the cooperatives' original records were lost or unavailable.

The committee requested that the state supervisor of assessments prepare an analysis of converting Verendrye Electric Cooperative to a centrally assessed property taxation system. The committee learned that it was not possible for Verendrye Electric Cooperative to provide a schedule showing an original cost of its property in each taxing district because cooperatives were not required to collect this information. Because it was not possible to make these calculations, the state supervisor of assessments testified that it was not possible to estimate the tax shift among taxing districts which would occur if Verendrye Electric Cooperative paid centrally assessed property taxes instead of the gross receipts tax and locally assessed property taxes on its land. Neither could Verendrye Electric Cooperative's total property tax, if it were centrally assessed, be estimated accurately because the Tax Department did not have the required information to multiply individual taxing district mill rates by the taxable value located in each taxing district.

Representatives of the Association of Rural Electric Cooperatives testified that in light of the study conducted by the state supervisor of assessments, the ad valorem system would not be easy to administer nor could one predict whether it would be revenue-neutral to political subdivisions. In addition, it would take each cooperative several years of work to assign investment costs properly to political subdivisions.

Wind

The study of wind energy development in this state included a study of wind energy development contract provisions, the potential economic benefits of wind energy development, the potential adverse impacts of wind energy development, consideration of transmission of electrical energy, and the impact on the electric industry of wind energy development.

The committee was informed that North Dakota has the greatest wind resource of any of the lower 48 states. The single biggest obstacle identified in developing this state's wind resource is constraints on the state's existing transmission grid. North Dakota exports nearly 60 percent of the power generated within this state, and it is likely that most wind-generated electricity also will be exported. Thus, additions to the current transmission grid will be necessary for a significant generation expansion in the state, regardless of fuel source. Other issues related to the development of wind energy include identification of the market for wind energy and possible environmental issues related to raptors and nesting waterfowl.

The committee considered, but did not recommend, a bill draft relating to a renewable electricity credit trading and tracking system by the Public Service Commission. The bill draft would have allowed the Public Service Commission to establish a program for tradable credits for electricity generated from renewable sources, would have allowed the commission to facilitate the trading of renewable electricity credits between states, and would have applied to all public utilities, including electric cooperatives and municipal electric utilities.

The committee made no recommendation concerning its study of wind energy development.

RECENT LEGISLATION

Since the creation of the committee in 1997, the committee has not made any recommendations concerning its studies. However, legislation has been adopted relating to the areas of study of the committee.

1999 Legislation

House Bill No. 1445 established the differentiation between electricity transmission lines and electricity distribution lines. The bill provided that except for purposes of transmission facility siting under NDCC Chapter 49-22 and regulatory accounting, including the determination of the demarcation between federal and state jurisdiction over transmission in interstate commerce and local distribution, for the purposes of Title 49 and Chapters 57-33 and 57-33.1, lines designated to operate at a voltage of 41.6 kilovolts or more are transmission lines and lines designed to operate at less than 41.6 kilovolts are distribution lines.

2001 Legislation

House Bill No. 1223 allowed installations on property leased by a taxpayer to qualify for a long-form income tax credit for installation of a geothermal, solar, or wind energy device installed before January 1, 2011. For a device installed before January 1, 2001, the credit is equal to 5 percent per year for three years, or for a device installed after December 31, 2000, the credit is equal to 3 percent per year for five years, of the actual cost of acquisition and installation of the device.

House Bill No. 1221 provided a sales and use tax exemption for production equipment and tangible personal property used in construction of a wind-powered electrical generating facility before January 1, 2011, if a facility has an electrical energy generation unit with a nameplate capacity of 100 kilowatts or more.

House Bill No. 1222 reduced the taxable valuation of centrally assessed wind turbine electric generators from 10 percent of assessed value to 3 percent of assessed value if the generation unit has a nameplate generation capacity of 100 kilowatts or more and construction is completed before January 1, 2011.

Senate Bill No. 2299 reduced the coal severance tax rate from 75 cents to 37.5 cents per ton and retained the two cent per ton research and development tax. The bill increased by .40 mill per kilowatt-hour the coal conversion tax for electrical generating plants based on nameplate capacity of a facility. The bill adjusted the coal severance and coal conversion tax allocation formulas to retain approximately equal allocations among state and political subdivision recipients as compared to allocations under previous law. The bill reduced the generation capacity of an electrical generating plant to be classified as a coal conversion facility from 120,000 to 10,000 kilowatts. The bill provided that each county may receive not less than it received in the previous calendar year under the coal conversion tax and for a county in which a facility is located that was not a coal conversion facility before the effective date of this bill, that county must receive an additional amount that is at least as much as was received in property taxes for that facility for taxable year 2001. In addition, the bill required the Public Service Commission to allow a public utility to recover all costs resulting from a coal severance tax pursuant to NDCC Chapter 57-61 and all costs resulting from a coal conversion tax pursuant to Chapter 50-60 in determining the value of property for ratemaking purposes.

2003 Legislation

House Bill No. 1348 provided that a transmission line placed in service by an investor-owned utility after September 30, 2002, is exempt from property taxes for the first taxable year the line is placed in service and is entitled to a property tax reduction of 75 percent for the second taxable year, 50 percent for the third year, and 25 percent for the fourth taxable year. After the fourth taxable year of operation, the transmission line and associated substations are exempt from property taxes and subject to a tax of $300 per mile. For transmission of electric cooperatives, the tax on a transmission line of 230 kilovolts or larger initially placed in service after September 30, 2002, is increased from $225 per mile to $300 per mile. The bill provided an exemption from this tax for the first taxable year a transmission line is placed in service and provided for a reduction of the tax by 75 percent for the second taxable year, 50 percent for the third taxable year, and 25 percent for the fourth taxable year.

Senate Bill No. 2286 provided that for taxation of rural electric cooperatives, the cooperative report of gross receipts must include a statement of the cost and amount of all electric energy purchased for resale and the cost and amount of all wind energy purchased for resale. The bill provided that all electric energy purchased for resale must be deducted from the cooperative's gross receipts before determining the cooperative's gross receipts tax liability.

House Bill No. 1363 reduced the time period during which the Public Service Commission may suspend a rate increase or decrease filing, classification, contract, practice, or rule from seven to six months beyond the time when it otherwise would go into effect. The bill also provided that notwithstanding that the Public Service Commission may suspend a filing and order a hearing, a public utility may file for interim rate relief as part of its general rate increase application and filing. If interim rates are requested, the commission can order, without a public hearing, that the interim rate schedule take effect no later than 60 days after the initial filing date. In addition, the bill established a procedure to calculate the interim rate schedule.

Senate Bill No. 2115 provided that information received by the Public Service Commission which was developed or obtained by the market monitor of the Midwest Independent System Operator, Inc., or its successor, is confidential.

2005 Legislation

Senate Bill No. 2239 provided a definition of and termination terms of a wind option agreement, which is a contract in which a property owner gives another the right to produce energy from wind on that owner's property. The bill voids a wind option agreement, wind easement, or wind energy lease if the development to produce energy from wind power has not occurred within five years.

Senate Bill No. 2018 reduced from 3 to 1.5 percent the portion of assessed value used to determine taxable valuation of wind turbine electric generation units with a generation capacity of 100 kilowatts or more. To qualify for the reduced taxable valuation, a generation unit must have a purchased power agreement executed after April 30, 2005, and before January 1, 2006, and construction must have begun after April 30, 2005, and before July 1, 2006. The reduced taxable valuation applies to that property for the duration of the initial purchased power agreement for that generation unit.

Senate Bill No. 2412 authorized electric providers to enter agreements with other electric providers having adjacent or intermingled electric supply facilities for the purpose of establishing service areas and designating the service locations to be served by each electric provider. The bill provided that electric providers may enter written agreements for the sale, transfer, exchange, or lease of equipment or facilities used to serve the areas that are the subject of a service area agreement. For purposes of electric service area agreements, electric providers include electric public utilities and rural electric cooperatives and a service area means a defined geographic area containing existing or future service locations established by an agreement among the electric providers and approved by the Public Service Commission.

House Bill No. 1324 allowed a public utility proposing to construct, lease, or make improvements to an energy conversion facility, renewable energy facility, transmission facility, or proposed energy purchase contract from another entity or person for the purpose of ensuring reliable electric service to its customers to file an application with the Public Service Commission for an advance determination of prudence regarding the proposal. The bill provided that the commission may issue an order approving the prudence of an electric resource addition if the public utility files with its application a projection of costs to the date of the anticipated commercial operation of the electric resource addition and the commission determines that the resource addition is reasonable and prudent.

House Bill No. 1314 authorized the Public Service Commission to establish or participate in a program to track, record, and verify the trading of credits for electricity generated from renewable and recycled heat sources among electric generators, utilities, and other interested entities within the state and with similar entities in other states. The bill provided that the income tax credit for installation of geothermal, solar, or wind energy devices can be carried forward for five taxable years. The bill also allowed a group of corporations filing a North Dakota consolidated tax return under the combined reporting method to claim the credit against aggregate North Dakota tax liability on the consolidated return.

Senate Bill No. 2278, which was vetoed by the Governor, would have provided that a public utility planning the construction of an energy conversion facility, major capital addition to an existing energy conversion facility in which the public utility has an ownership interest, new transmission facility, new renewable energy facility, or new power purchase that was expected to have a material impact on rates could have applied to the Public Service Commission for a rate stability plan providing for the phasein of rate increases before the commercial operation of the electric resource addition.

Senate Bill No. 2133 established a siting process expense recovery fund. The bill provides that fees received from applicants for a certificate of site compatibility, certificate of corridor compatibility, or waiver and any additional fees imposed for the completion of an energy conversion facility site, transmission facility corridor, or transmission facility route evaluation and designation process by the Public Service Commission must be deposited in the fund. All money deposited in the fund is appropriated on a continuing basis to the commission to pay expenses incurred in the siting process.

House Bill No. 1283 increased the threshold for an energy conversion facility that is subject to the Energy Conversion and Transmission Conversion Siting Act from a facility that generates 50,000 kilowatts or more of electricity to a facility that generates 100,000 kilowatts or more of electricity.

House Bill No. 1169 established the North Dakota Transmission Authority. The bill provided that the North Dakota Transmission Authority is created with the purpose of diversifying and expanding this state's economy by facilitating development of transmission facilities. In support of that purpose, the Transmission Authority was given the power to borrow money and issue up to $800 million in evidences of indebtedness and do any and all things necessary or expedient for the purposes of the Transmission Authority.

The Transmission Authority may construct transmission facilities after publication of its plans in certain newspapers and if no one delivers to the Transmission Authority notice indicating willingness to construct transmission facilities contemplated by the Transmission Authority and a bond as required by the Transmission Authority. If the Transmission Authority receives this notice, the Transmission Authority must find that exercising its authority would be in the public interest before constructing transmission facilities. The public interest includes the economic impact to the state, economic feasibility, technical performance, reliability, past performance, and the likelihood of successful completion and ongoing operation. The transmission facilities are not under the jurisdiction of the Public Service Commission and are exempt from property taxes for a period not to exceed the first five taxable years of operation. The Transmission Authority is to deliver a written report on its activities to the Legislative Council each biennium.

TESTIMONY AND DISCUSSION ON TRANSMISSION ISSUES

North Dakota Transmission Authority Report

The Legislative Council delegated to the committee the responsibility of receiving the report required of the North Dakota Transmission Authority on its activities.

The committee received multiple written reports from the Transmission Authority. The committee was informed that the Transmission Authority has been creating procedures and working with other states, the Federal Energy Regulatory Commission, and Congress to promote positions that will encourage transmission in this state. In addition, the Transmission Authority has been working with Lignite Vision 21 project applicants on developing transmission plans for their projects.

The committee received testimony that the notice of need in the proposed process before building a transmission facility by the Transmission Authority would be an assessment done within the Industrial Commission. The determination of need does not require a hearing.

The committee received testimony on the bonds the Transmission Authority may issue. The committee was informed that the attractiveness of a bond would depend on the project and that state involvement would make a Transmission Authority bond more attractive. For a Transmission Authority bond to be exempt from taxation under the present tax code, the bond must be for a project with no private use. The committee was informed the Internal Revenue Service would most likely look at the primary use and not divide a project on a percentage basis to offer a tax exemption.

Wyoming Infrastructure Authority

The committee received testimony on the Wyoming Infrastructure Authority. The Wyoming Infrastructure Authority was created in 2004 and was patterned after the Wyoming Pipeline Authority, which promotes the expansion of natural gas and oil. The authority is governed by a five-member board appointed by the Governor. The purpose of the authority is to diversify and expand the economy through the development of transmission facilities to the point that the authority may own and operate an interstate transmission line. However, the authority does not own any transmission lines and there is no anticipation that the authority will own transmission lines because before owning a transmission line the authority must offer the opportunity to the private sector. The business model of the authority is to act as a catalyst by providing front-end capital.

The Wyoming Infrastructure Authority is funded with a $6.6 million loan. The funding is divided $1.6 million for operating expenses and $5 million for feasibility study work. There is consideration being given to double the funding for feasibility study work. The intent of the authority is to make money and repay the loans.

The committee received testimony on three projects of the Wyoming Infrastructure Authority. First, the authority financed the Hughes transmission line for Basin Electric with $34.5 million in revenue bonds. The repayment schedule is over a period of 20 years and the project was financed through a private placement with the state treasury. Second, the authority is working with two independent transmission companies to determine the feasibility for a line from the Powder River Basin to Denver and for a line to reach Boise and Salt Lake City. Third, the authority is working with three other states in the prefeasibility phase in developing the Frontier Line.

After Wyoming created an authority, South Dakota, Kansas, Idaho, and North Dakota created transmission authorities and New Mexico is in the process of creating a similar transmission authority. The creation of authorities provides an opportunity for collaboration among the states, especially in dealing with the federal government. The committee was informed that collaboration among the states would be especially valuable in lobbying for making the bonds issued by an authority tax-exempt.

The committee received testimony comparing the Wyoming Infrastructure Authority and the North Dakota Transmission Authority. The entities are similar in structure; however, the levels of funding and staffing are much higher in Wyoming. The committee was informed that the North Dakota Transmission Authority does not have a competitive disadvantage with the Wyoming Infrastructure Authority because the Transmission Authority in this state does not compete with the Wyoming Infrastructure Authority. Wyoming and North Dakota are in different sides of the market divide. Wyoming markets energy to the South and West and North Dakota markets energy to the East. The committee was informed that there is no advantage between the two states as to the issuance of bonds. A difference between the two authorities is that North Dakota is part of an ISO and Wyoming is not. The committee was informed that there may be regulatory or cost recovery opportunities by being part of an ISO. The committee was informed that it is not foreseeable that the North Dakota Transmission Authority will become more like the Wyoming Infrastructure Authority.

The committee was informed that there are a number of projects being proposed for transmission lines in Wyoming; however, they are usually backed by companies without strong credit. The committee was informed that the big players are not involved because of regulatory barriers, which impair the creation of new transmission lines.

Cost Allocation and Recovery

The committee received testimony on the Northwest Exploratory Study and the Midwest ISO. The purpose of the Northwest Exploratory Study was to identify the benefits of the best single-line and two-line transmission expansion given a projected 2,000 megawatt wind and coal generation expansion in North Dakota and South Dakota, which would be marketed to Minneapolis and St. Paul.

The committee was informed that the Midwest ISO is a FERC-approved regional transmission organization that oversees the wholesale electric power grid in 15 states to facilitate nondiscriminatory and open access to the grid. Basin Electric Power Cooperative, MinnKota Power Cooperative, Inc., and the Western Area Power Administration are not in a regional transmission organization. However, Basin Electric Power Cooperative and the Western Area Power Administration are nontransmission owning members.

The Midwest ISO provides the following services:

- Scheduling and selling wholesale transmission services.
- Operating a day ahead and real-time energy markets.
- Centralized dispatch of generation.
- Management of grid congestion.
- Regional transmission planning.
- Market monitoring.

The committee received testimony on cost recovery for the builders of transmission facilities. The committee received information on the Midwest ISO proposal before FERC on transmission cost allocation. The committee was informed that a cost allocation formula and the administration of cost recovery need to be confirmed before there will be major construction of transmission lines by generators of electricity.

The Midwest ISO proposal before FERC on transmission cost allocation would provide a generator building a line greater or equal to 345 kilovolts a reimbursement of 50 percent with 20 percent of that coming from a postage stamp rate throughout the Midwest ISO footprint and 80 percent from nearby rate zones. For example, if generator XYZ Company builds a line costing $100 million, under the Midwest ISO proposal the XYZ Company would be eligible for partial repayment of $50 million. Ten million dollars would come from all utilities in the Midwest ISO footprint. Forty million dollars would come from utilities impacted by the addition. The 50 percent reimbursement for a line less than 345 kilovolts would come completely from nearby rate zones. Once FERC determines the reimbursement rates, the rates will become part of tariff language and will apply to all projects built under the tariff. Present projects are reimbursed through a license plate scheme and that cannot be changed until 2008. Committee discussion included that the postage stamp portion of generator reimbursement should be higher.

Support for the Midwest ISO proposal is widespread but not universal. The committee was informed that 11 of 15 states in the Midwest ISO footprint agree with the proposal. The Industrial Commission (and thus the North Dakota Transmission Authority) supports the compromise contained in the Midwest ISO proposal. It was argued that the Midwest ISO proposal is good for North Dakota because a final determination provides certainty for the generators in developing new transmission. The Federal Energy Regulatory Commission order adopted the Midwest ISO proposal. The committee was informed, however, that the reimbursement has not been determined as to whether it is a lump sum, payments over time, or credits on transmission bills.

The committee considered, but does not recommend, a bill draft that would have allowed a public utility to have an automatic rate adjustment for recovery of capital and operating costs incurred to comply with environmental laws or costs incurred to repair damages caused by an act of terrorism, sabotage, or a natural disaster. Presently, these costs are recovered through rates after the next general rate case. The bill draft was requested after a committee member spoke with legislators in other states about disasters in the other states. It was argued that utilities need to have immediate action when there is a disaster so utilities may move quickly to make repairs with certainty of cost recovery.

Proponents argued that under the bill draft a public utility would make a filing and would begin to recover costs immediately without a hearing and the Public Service Commission could review the filing and make an adjustment if necessary. However, the committee was informed that under the bill draft a fact scenario in which the Public Service Commission would negate the filing could not be realistically envisioned. The committee was informed that the conditions precedent for filing the expedited tariff under the bill draft are very certain events.

Proponents also argued that the procedure in the bill draft was comparable to the administration of the fuel cost adjustment. The fuel cost adjustment has nothing to do with the general rate and goes up and down on a monthly basis. It also was argued that delayed recovery is adverse to the shareholders' interests.

The committee received testimony on transmission cost recovery in Minnesota and South Dakota. Both states allow the timely recovery of new transmission investments at a rate of return based on the most recent rate case. The committee was informed that the market does not tolerate regulatory lag well. If investors have to wait until the completion of a large project to receive any return, it is difficult to obtain investors.

The committee considered, but does not recommend, a bill draft that would have allowed a public utility to automatically adjust rates for the recovery of capital and operating costs incurred for a new or modified electric transmission facility with the capacity of 41.6 kilovolts or more and five miles or more in length. The committee was informed that the language in the bill draft is borrowed from a recently enacted South Dakota bill.

Proponents of the bill draft argued that the bill draft would spur transmission growth in this state. Presently, interest costs incurred for the completion of a transmission facility are recovered when the public utility files a general rate case. At present, shareholders are paying for the cost of facilities constructed between rate cases. It was argued that as long as returns are good enough, shareholders absorb the cost. However, future plans are for major transmission projects that will require more substantial investment than in the past and there will be a need for timely recovery. If public utilities are allowed to timely recover costs, the repayment costs should be reduced, which will result in lower rates for consumers in the long term. The committee was informed that the intent of the bill draft is to have the expedited tariff available for major investments and maintenance be included under the general tariff.

The committee considered a bill draft to allow a public utility to file a tariff that provides an expedited adjustment of rates to recover jurisdiction capital and operating costs incurred for a new or modified electric transmission facility. The bill draft had two parts. First, the Public Service Commission may approve a tariff that describes a process for the adjustment of rates. Second, the bill draft describes what that tariff must include. The rate adjustments are under the tariff and are rather automatic; however, the Public Service Commission approves and reviews the rate adjustments. The bill draft required the Public Service Commission to approve the rate adjustment unless the adjustment does not comply with the tariff or the incurred costs are not reasonable or prudent.

At present, the recovery of transmission facility costs is done through a general rate case and a fuel cost adjustment is allowed above the base rate provided for in the general tariff. This adjustment prevents having a general rate case every time there is a fuel cost increase. The bill draft allowed public utilities to recover transmission facility costs as soon as they are incurred, as with the fuel cost adjustment. Whether the expedited adjustment for the recovery of transmission facility costs will be a separate line on a customer's bill, as is the case with the fuel cost adjustment, was not part of the bill draft. The committee was informed that certain utilities have a preference to provide for a separate line on customers' bills for a rate adjustment for transmission facility costs.

The committee was informed that the charges allowed in the bill draft would accrue to North Dakota customers in the amount North Dakota customers are benefited. The bill draft referred to "jurisdictional capital and operating costs" and the word "jurisdictional" applies only to the costs attributable to ratepayers in this state. The methodology for determining what is attributable would come from FERC. Under this methodology, a portion of the cost would be allocated to the entire Midwest ISO footprint and the majority of the cost would be paid by the customers of the utility that built and benefit from the line.

The committee received testimony in support of the bill draft and did not receive any testimony in opposition to the bill draft. The committee was informed that the procedure for the tariff to be changed would take approximately six months. However, a rate adjustment may not happen for years because there needs to be a qualifying project.

Siting

The committee received testimony on transmission and the barriers to building transmission facilities. The committee reviewed this state’s laws and model legislation enabling cooperation and coordination among the states when siting electric transmission lines that cross state borders. The committee received testimony on the National Conference of State Legislatures electric transmission planning and siting sample legislation. The committee was informed that the Public Service Commission's authority under existing statutes is sufficient to enable cooperation with other states and the federal government. North Dakota Century Code Sections 49-22-14.1 and 49-02-02 are sources of cooperative authority for the commission. Although the commission's jurisdiction ends at the border of this state, that does not preclude the commission from working with other states, as the commission does through the Midwest ISO. The committee was informed that "international" may need to be added to Section 49-22-14.1 to allow for international cooperation; however, the commission has cooperated with Canada on siting issues without this addition.

The Public Service Commission would use this information on the interstate benefits of a proposed project in determining whether to give a preference for the siting of an energy conversion or transmission facility. The committee was informed that the commission will not have to give a preference because generally there is no competition between projects.

The Energy Policy Act of 2005 gave authority to FERC and the Department of Energy to address issues of reliability and the designation of interstate bottlenecks. The backstop authority under the Energy Policy Act of 2005 could allow FERC to allow siting when an important transmission line is not allowed by a state. The committee was informed that the closest transmission bottleneck is from Minneapolis going east. As such, FERC probably will not exercise its backstop jurisdiction in this state because this state has low-cost generation and low load. In addition, the committee was informed that the public utility commissions in this area are working together and therefore there is no need for the use of the backstop authority.

CapX 2020

The committee received testimony on where transmission facilities need to be expanded. The committee was informed that the transmission facilities in this state are generally adequate; however, there are bottlenecks in other states. The committee received testimony on CapX 2020, a group of eight utility partners. The group created a 15-year plan for the construction of new facilities. The plan is intended to address the 8,500 megawatts in new generation and the transmission that will be needed to meet the 2020 forecast of 6,300 megawatt-load for the North Central United States, 2,400 megawatts of which are from renewables.

As discussed under **Cost Allocation and Recovery Siting**, the committee addressed the two legislative recommendations of the plan--automatic cost recovery and siting across state boundaries.

Wind Energy

The committee received testimony on wind projects in the state and on state and federal incentives for wind development. The committee was informed that there are a number of wind monitoring program grants available. The usual grant is a matching grant up to $10,000, which is provided over a three-year period.

Minnesota requires Otter Tail Power Company to use 10 percent renewable energy. The committee was informed that a 10 percent renewable energy requirement may be met without significantly increasing costs. The Minnesota Public Utilities Commission has determined that green energy does not count toward the 10 percent renewable energy requirement. The committee was informed that the green community did not want green energy included within the renewable energy requirement so there would be more renewable energy used. This determination, combined with increased costs, made a wind farm project in North Dakota unfeasible.

The committee was informed that the raw cost of wind power is relatively inexpensive; however, there are other considerations with an intermittent source. At a 10 percent renewable energy requirement, Otter Tail Power Company can manage the incremented shortfalls of wind without building other plants. If that percentage were increased, Otter Tail Power Company would have to build more gas backup plants. This would subject Otter Tail Power Company to purchasing gas on the spot market, which can be relatively expensive.

The committee received testimony on the Western Area Power Administration's *Dakotas Wind Transmission Study*. The committee was informed that some transmission problems may be solved through new technologies. The study shows limits to the nonfirm available capacity must be solved with systems additions, such as series compensation.

Although customers require continuous electricity supply, there does not need to be a total backup for wind if a system is designed to have the capacity serve the demand. The committee was informed that there does not need to be an instantaneous backup for wind if there is good wind forecasting. Forecasting wind is important because an unexpected stop in wind is a major problem.

Committee discussion included that wind energy has its positives but wind is not consistent and the economics of wind energy do not promote the building of transmission capacity for wind.

The committee received testimony on wind energy from a wind developer. There are some benefits in placing a wind farm next to the demand, but economics require wind farms be placed where there is lots of wind. However, taking transmission into account, the ideal customer would be a high-volume user who wants to use green energy and locate in this state.

The committee was informed that it costs four to seven cents per kilowatt for the production of wind energy, including federal subsidies. Without the federal subsidies, the cost would increase approximately 40 percent.

Financing

The committee received testimony on financing for transmission projects. The committee reviewed leaseback transactions. The original purpose of a leaseback transaction was to allow a tax-exempt entity like a city to transfer an asset to a private entity and lease the asset back. The transaction would be structured so the tax-exempt entity would receive a cash benefit at execution of the agreement and retain operating control and the private entity would deduct the cost of the transaction and depreciate the asset that was involved in the transaction. Federal tax law has been changed to remove any economic benefit for lease contracts between tax-exempt and private entities. The committee was informed that the problem with leaseback transactions was that the cities did not give up any control when transferring water systems to third parties.

The committee received testimony on the financing of transmission projects through the state of North Dakota guaranteeing to purchase transmission supply. The tax advantages may make the arrangement able to compete with tax-exempt bonds. Under the concept, a private entity would be established for the purpose of providing power transmission capacity through construction of the intrastate transmission asset. The state would enter a long-term, take-or-pay transmission supply contract with the private entity. The state would enter long-term transmission supply contracts with transmission users. The private entity would obtain construction financing and select a contractor and operator through a competitive procurement process. Upon completion of construction, the private entity would enter a leveraged sale leaseback for the permanent financing of the plant. The private entity supplies transmission, collects supply payments from the state, and services the lease and operation and maintenance agreement obligations. The ongoing operation and maintenance would be conducted by a third-party operator under contract with the private entity.

Because the useful life of a transmission facility is usually 25 years, generally the state would purchase capacity for 25 years and would receive revenue from the users to pay for the capacity. The state creates the demand that drives the concept. The state of North Dakota would be a major risk-taker because the state would buy all the transmission capacity; however, before entering this financing arrangement, if prudent, the state would have buyers for the capacity.

The committee received testimony on clean renewable energy bonds (CREBs). These bonds are allowed in certain circumstances under the Energy Policy Act of 2005. The Act allows state and local governments, cooperative utilities, certain lenders, and Indian tribes to issue CREBs to finance certain renewable energy and clean coal facilities. A CREB is a tax credit bond in which the interest on the bond is paid in the form of tax credits by the federal government. In essence, a CREB only requires that the principal be paid back.

Recommendation

The committee recommends Senate Bill No. 2031 to provide for an expedited rate adjustment to recover transmission facility costs. The bill allows for a change in the tariff to allow the rate adjustment. The rate adjustment must be approved by the Public Service Commission unless the rate adjustment does not comply with the tariff or the incurred costs are not reasonable and prudent.

TESTIMONY AND DISCUSSION ON COMPETITION

The committee received testimony from Imation, Wahpeton, on the need for competition in electric rates. The objective of Imation is to grow the manufacturing plant in Wahpeton and electrical rates enter these equations. The committee was informed that Imation pays more for electricity from Otter Tail Power Company in North Dakota than if Imation received electricity in Minnesota or South Dakota from Otter Tail Power Company.

The main competition for Imation comes from China and India. The committee was informed that energy is more reliable in the United States than in foreign countries. However, foreign countries have a significant advantage in the cost of labor. It was argued that to compete, Imation cannot do much about what foreign countries do, but should be able to work with key suppliers in this country.

The committee was informed that the increase in rates to Imation were attributed to the fuel cost adjustment, which relates to power purchased on the wholesale market. The fuel cost adjustment allows Otter Tail Power Company to pass through dollar per dollar to the customer the increased cost and has been high because of planned outages at the Coyote Plant and Big Stone and rail issues that have had Big Stone operating at half capacity.

The committee was informed that Otter Tail Power Company may not easily change general rates; however, general rates are divided by different groups of users. Imation is the sixth largest customer of Otter Tail Power Company in North Dakota. There are discounts for volume users and Imation is using the available discounts. However, the committee was informed that a business one-fortieth the size of Imation receives the same rates from Otter Tail Power Company. The committee was informed that rate structures favoring residential customers over business customers are policy-driven and are not set by economic pressure. The committee was informed that Otter Tail Power Company would investigate at the next general rate case a rate structure that provides better rates for business users. There has not been a rate case for Otter Tail Power Company since 1983 because the company has not underearned. The committee was informed that rate cases are time-consuming and expensive. The committee was informed that Imation needs a short-term solution so that jobs can remain in Wahpeton.

The committee was informed that Otter Tail Power Company could negotiate a special rate with Public Service Commission approval. Under NDCC Section 49-04-07, the Public Service Commission has the authority to approve electric service rate agreements negotiated with individual customers. Since 1988, 18 of these contracts have been approved, mostly for economic development or load-retention purposes. In short, Otter Tail Power Company can change its rate structure without a full rate case.

The committee received testimony from Dakota Valley Cooperative on rates charged customers outside Wahpeton. Dakota Valley may not serve Imation because Imation is within Wahpeton city limits. The committee was informed that cooperatives may set a rate at any level and that Dakota Valley rates are cost-based rates, i.e., rates are set with regard to usage. The committee was informed that industrial customers are on standard rates; however, occasionally new customers have a lower rate because of investments in the transmission system. The committee was informed that the 4.5 cents per kilowatt-hour for Min-Dak Farmers Cooperative is the standard Dakota Valley rate. The rate for Cargill is less because of investments in the transmission system. Both these rates are lower than rates paid by Imation to Otter Tail Power Company.

The committee was informed that the Public Service Commission met with Imation and Otter Tail Power Company on August 31, 2006. Imation gave Otter Tail a proposal for a time-of-day rate. Otter Tail was to review the proposal and provide a counteroffer or accept the offer.

TESTIMONY AND DISCUSSION ON COMMITTEE EXTENSION

The Electric Industry Competition Committee is scheduled to sunset in 2007. Committee discussion included that the contentious issues brought before the committee make a strong case for the continuation of the committee.

The committee considered, but does not recommend, a bill draft relating to the continuation of the Electric Industry Competition Committee until August 1, 2009. Committee discussion included that the committee should continue but the scope of the committee should be broadened to include all energy development and transmission.

The committee considered a bill draft to create the Energy Development and Transmission Committee as a successor to the Electric Industry Competition Committee. Committee discussion included support for additional language to include that the committee is to study each facet of the energy industry from the obtaining of the raw natural resource to the processing, distribution, and consumption in addition to sale of the final product. However, an amendment to this effect failed.

Committee discussion included support for the name of the committee and the sentence designating the committee's area of study being inclusive of all processes of energy development without extra words.

Committee discussion included whether the study of oil is or is not included within the committee's study jurisdiction. However, committee discussion pointed out the intent of the bill draft is that petroleum transmission may be studied during the interim and the intent of the bill draft is to include the study of oil.

Committee discussion included the desire that the Transmission Authority bill last session should have been addressed during the interim when there was time to thoughtfully consider the provisions of the bill. Committee discussion included that the state needs to address transmission because transmission is the most important issue in energy.

The committee was informed that the Legislative Council could give the Energy Development and Transmission Committee more studies in addition to the statutory duties. The Energy Development and Transmission Committee would be required to study "each facet of the energy industry." By creating a statutory committee, the Legislative Council would be required to study the subject matter in the bill draft; however, the Legislative Council could manage the workload among committees so there is no duplication.

The committee discussion included support for the membership being equal from the majority and minority parties in the House and the Senate. However, an amendment to this effect failed.

Recommendation

The committee recommends House Bill No. 1028 to create the Energy Development and Transmission Committee of the Legislative Council.

TESTIMONY AND DISCUSSION ON TAXATION

The committee received testimony on the taxation of the electric industry. In particular, the committee reviewed two bill drafts proposed during the 2003-04 interim as described under **PREVIOUS STUDIES**, **2003-04 Study**. The committee was informed there have been no discussions in the industry since the 2003-04 interim on the taxation issue.

The committee received testimony on the in lieu of property tax bill draft. Proponents argued that in lieu of taxes are more transparent and uniform than property taxes based on formulas. The goal of the proposal was to be revenue-neutral to political subdivisions. However, the committee was informed that the in lieu of property tax bill draft will not hold political subdivisions harmless but the impact would not produce great shifts in revenue. As to the taxes paid by utilities, the committee was informed that it is impossible to adopt a new tax plan that is revenue-neutral and that does not increase any utility's tax payments.

The committee was informed every cooperative, Xcel Energy, Inc., and Otter Tail Power Company supported or did not oppose the bill draft during the 2003-04 interim. The committee was informed that although Otter Tail Power Company testified during the 2003-04 interim that the in lieu of property tax bill draft would have provided simplicity to taxation and was supported by the company, the company did not endorse the bill draft due to concerns with tax distribution inequities raised in other testimony. In addition, the neutrality of Xcel Energy, Inc., toward the proposal was changed due to opposition to the administrative complexity created by the bill draft. The committee was informed that the bill draft would create an administrative burden for MDU Resources Group, Inc., because the electric and gas functions would have to be separated for taxation purposes.

The committee received testimony on the property tax bill draft that provided for rural electric cooperatives' property to be centrally assessed and subject to property tax. The committee was informed that in 1997 there was reason to investigate changes in the taxation system because the electric industry was facing competition with deregulation. It was argued that because there has not been deregulation, there is no need to change taxation. However, in the alternative, it was argued that if a change were to be made, taxation of rural electric cooperatives should be changed to a system based on the value of the property.

The committee was informed that applying centrally assessed property taxes to rural electric cooperatives is administratively burdensome because electric cooperatives have not maintained records on original investments in quarter-quarter sections as is needed for this type of taxation. To the contrary, the committee was informed that although original costs may be an issue in changing to a new system of centrally assessed property, fair assumptions may be made and costs determined. It was argued that another administratively burdensome factor would be that the state would have to add 22 rural electric cooperatives to the central assessment.

The committee received testimony on a study done by Covenant Consulting Group. The committee was informed that the reason for the study was to provide information on property taxes of electric utility entities. The focus of the study was on the differences in property taxation between cooperatives and investor-owned utilities and the resulting impact those tax differences have on the local taxing districts. The study focused on Bismarck and Dickinson.

The study concluded that the cities of and school districts in Bismarck and Dickinson would receive significantly more property tax dollars if the areas within those taxing districts currently served by cooperatives were served by investor-owned utilities or if the cooperatives were taxed the same as investor-owned utilities. Because taxes are based on budgets, as long as the budgets stayed the same there would not be an increase in total tax collections but a decrease in taxes to others. Increased taxes upon electric utilities may be passed on to the consumer; however, the reduction in other taxes should make the net effect the same. The committee was informed that the argument that taxes should not be increased on electric utilities because they will be passed on to consumers is the same argument that could be used for removing all taxes on electric utilities.

The committee was informed that the results of the study did not apply to small cities. For the study to be done in a small city, the study would need information on how much tax each meter generates for the gross receipts tax. The study only looked at two cities, not the whole state. The report on the study was provided without a recommendation. The committee was informed that if the committee is concerned with the conclusion of the report, the committee may wish to have an independent study; however, an independent study would be expensive.

The committee received testimony in opposition to the findings of the study. The committee was informed that although a different study may have come to the same result no matter who commissioned the study, the questions would have been different if commissioned by the rural electric cooperatives. The committee was informed that the application of property taxes to rural electric cooperatives would result in a shift in taxes to rural areas around cities.

Committee discussion included that line mile tax revenue allocated to counties for new developments in the outskirts of cities should be examined. It was argued that the cities should have the revenue. To the contrary, it was argued creating a third tier of taxation creates a complexity that is unnecessary and every area should be treated the same. Committee discussion included that the issue is complex because people from rural areas go to the cities and pay local sales taxes for projects the people from rural areas do not use.

REPORT ON EMERGENCY 911 TELEPHONE SYSTEMS STANDARDS AND GUIDELINES

The Legislative Council delegated to the committee the responsibility to receive a report from the Division of State Radio on the operation of and any recommended changes in the emergency 911 telephone system standards and guidelines. The report provided for under NDCC Section 57-40.6-11 requires the Division of State Radio to report annually to the Legislative Council on the operation of and any recommended changes in the emergency 911 telephone system standards and guidelines. Under Section 57-40.6-10, the governing body with jurisdiction over an emergency 911 telephone system is to designate a governing committee. The governing committee is to hire a 911 coordinator and provide for the operation of a 911 system subject to particular requirements of this section, i.e., the standards and guidelines.

The committee was informed that State Radio recommended no change.

REPORT ON CITY AND COUNTY FEES ON TELEPHONE SERVICE

The Legislative Council delegated to the committee the responsibility to receive a report from the Public Safety Answering Points Coordinating Committee on city and county fees on telephone exchange access service and wireless service. The report provided for under NDCC Section 57-40.6-12 requires the Public Safety Answering Points Coordinating Committee to provide by November 1 of each even-numbered year to the Legislative Council a report on income, expenditures, and status of the emergency services communication system. The information for the report is provided for by the cities and counties that have a telephone exchange access service and wireless service fee. Under Chapter 57-40.6, a governing body of a city or county may provide for a resolution, subject to the vote of the electors, for the imposition of a fee of up to $1 per month per telephone access line and wireless access line for providing an emergency services communication system, and in the case of wireless, enhanced 911 service. The Public Safety Answering Points Coordinating Committee is composed of one member appointed by the North Dakota 911 Association, one member appointed by the North Dakota Association of Counties, and one member appointed by the Adjutant General to represent the Division of State Radio.

For the first time the revenue received by local jurisdictions from wireless communications companies exceeded that received from landline companies. As of May 2005, all carriers and public safety answering points are compliant with Phase 2 of the wireless enhanced 911 plan.

The committee reviewed a performance audit report on the collection and use of 911 fees. The performance audit report had been presented to and accepted by the Legislative Audit and Fiscal Review Committee. The committee was informed that the legislation recommended in the performance audit is being addressed by a committee organized by the Adjutant General.