ELECTRIC INDUSTRY COMPETITION COMMITTEE

North Dakota Century Code (NDCC) Sections 54-35-18 through 54-35-18.3 create the Electric Industry Competition Committee. Section 54-35-18 states 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 that this competition has potential benefits and adverse impacts on the state's electric suppliers as well as on their shareholders and customers and citizens of this state.

Section 54-35-18.1 outlines the composition of the committee and directs the committee to study the impact of competition on the generation, transmission, and distribution of electric energy within this state and on this state's public utilities, rural electric cooperatives, municipal electric utilities, and power marketers.

Section 54-35-18.2 outlines the study areas 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.

Section 54-35-18.2 also requires the committee to study 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 to specifically address 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.

Committee members were Representatives Al Carlson (Chairman), Robert Huether, and Matthew M. Klein and Senators Randel Christmann, Pete Naaden, and Larry J. Robinson.

The committee submitted this report to the Legislative Council at the biennial meeting of the Council in November 2000. The Council accepted the report for submission to the 57th Legislative Assembly.

ELECTRIC INDUSTRY RESTRUCTURING

Background

Establishment of the committee in 1997 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. Nationally, builders of new technology generating plants, the natural gas industry, and states with high electric rates or excess generating capacity are promoting electric industry restructuring. Arguments put forward for restructuring or implementing competition in the electric industry include greater customer choice, the possibility that open competition may lower costs, encourage generating efficiency, and allocate capital. Risks and challenges of retail competition, however, 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.

Traditional Rationale for Regulation

Under the current industry structure, electricity is provided to retail customers by utilities that have geographic monopolies for the provision of electric service within their service territories. Customers within a utility's service territory must purchase their electric services from that utility. These services include generation, transmission, distribution, customer service, meter reading, demand-side management, and aggregation and ancillary services.

Generally, three major types of electric utilities exist--investor-owned utilities, municipal and other government-owned utilities, and rural electric cooperatives. States regulate investor-owned utilities regarding their profits, operating practices, and pricing to end-use retail customers, while the Federal Energy Regulatory Commission governs the pricing of wholesale bulk power sales and transmission services. Although the committee is directed to study the impact of competition on the generation, transmission, and distribution of electric energy, nationwide, the restructuring debate is over whether and how to separate the generation of electricity from other electric services in order to allow retail customers to shop for the electricity supplier of their choice.

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 electric utility franchises, 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. Similarly, the state's Territorial Integrity Act, Sections 49-03-01.1 through 49-03-01.5, requires 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 of the corporate limits of any municipality. However, Section 49-03-01.3 exempts electric public utilities from the requirement that they obtain a certificate of public convenience and necessity for an extension of electric distribution lines within the corporate limits of a municipality in which it 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.

Traditionally, an electricity customer must purchase all its 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. 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 both a power portfolio, combining power from a variety of sources in order to match the demand for power with adequate power supply and a portfolio of customers with combined demands in order 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, selling 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 their electricity supplier. If generation is unbundled from transmission and distribution, under this scenario, these services may remain regulated functions.

The Regulatory Compact

The provision of electric service has been considered to exhibit the characteristics of a natural monopoly. According to economic theory, a natural monopoly exists in a market if one service provider in the market can serve customers more efficiently than many competing service providers. A common explanation for electricity provision as a natural monopoly is that allowing competitors to string duplicate transmission and distribution lines and construct excess generation capacity would waste resources and increase electric rates for customers. Generally, the characteristics of a natural monopoly include a high, upfront capital investment in technology; limited storability of a provided service or goods; limited transportability, requiring operations near the end users; and cost advantages of large and integrated systems as a result of better utilization of existing capacity or economies of scale and scope.

In markets exhibiting the characteristics of a natural monopoly, government intervention in the form of regulation over a single firm is considered necessary to provide the market discipline competition cannot provide. In exchange for this monopoly, each utility is required to serve all customers within its service territory and to provide quality service at just and reasonable rates. The utility is permitted to recover reasonable and prudent expenses associated with its provision of service plus a reasonable rate of return on its investment made to serve customers. This exchange is known as the regulatory compact.

Under the regulatory compact, the traditional method of rate determination has been rate of return regulation. This type of regulation is designed to ensure that utilities offer their services at prices that are based on the cost of the services rather than on the value customers place on those services. In traditional rate of return regulation, the regulating entity determines the revenue requirement (the reasonable and prudent cost of providing utility service), allocates the requirement among customer classes, and translates the allocated revenue requirement into rates. Traditional rate of return regulation has been criticized for allowing a utility and its shareholders to pass on all the utility's costs and risks to ratepayers, and because the utility faces minimal risks, the utility has little or no incentive to increase its operating efficiency or to minimize its expenses.

As an alternative to traditional rate of return regulation, some commentors have advocated and some states have implemented various forms of incentive regulation, including flexible regulation, targeted incentive plans, external performance indexing, price and revenue caps, and performance-based regulation. However, these forms of incentive-based regulation also have their critics. Performance-based regulation opponents have argued that this type of regulation may result in the selection of inappropriate performance benchmarks; incorporation of too many, or contradictory, societal or regulatory goals into the performance-based regulation plan; unreasonable returns to shareholders; or exacerbation of the information asymmetry between utilities and regulators.

Federal Actions to Promote Competition

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 intended to achieve these goals by abandoning the use of natural gas to make electricity, mandating conservation of oil, and encouraging industry to cogenerate electricity using waste heat. The Act required utilities to purchase bulk power produced from cogeneration facilities to ensure that it was financially attractive. States were allowed, however, to determine the avoided costs (the amount of money an electric utility would need to spend for the next increment of electric generation that it instead buys from a cogenerator) and quantity of such power. Some states capped the price at the utility's avoided costs and limited the obligation to purchase to the capacity of the utility. Other states allowed prices above the utility's avoided costs and ordered purchases of additional generation whether needed or not.

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 both new wholesale buyers and new generators of power. 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 (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, the Federal Energy Regulatory Commission issued Order Nos. 888 and 889, which essentially 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, Order No. 888 recognizes the right of utilities to recover legitimate, prudent, and verifiable costs stranded by opening up the wholesale electricity market, i.e., stranded costs, and requires public utilities to functionally unbundle their power and services for wholesale power transactions by requiring the internal separation of transmission from generation marketing services.

Electric Industry Restructuring Initiatives in Other States

Twenty-one states have enacted electric industry restructuring legislation. These states include Arkansas, California, Connecticut, Delaware, Illinois, Massachusetts, Maryland, Maine, Montana, New Hampshire, New Jersey, New Mexico, Nevada, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Virginia, and West Virginia. Four of these states--California, Massachusetts, Pennsylvania, and Rhode Island--have passed the date on which competition is to be phased in. Each of the four states that has passed the date on which competition is to be phased in are in a transition period during which most customers continue to pay a regulated electricity rate. Competition for Illinois industrial customers will begin later this year. Four state public utilities commissions--Arizona, Michigan, New York, and Vermont--have issued comprehensive restructuring orders. Twenty-one states and the District of Columbia have active legislative or regulatory processes underway to study restructuring and propose implementing legislation. Five states have undertaken little preliminary activity to date.

Competition has taken hold more quickly among industrial and commercial customers than among residential customers in California. Almost all residential customers continue to pay a regulated rate for power, albeit one that was reduced by 10 percent through a provision in California's restructuring legislation. As of early 1999, .9 percent of residential customers had switched providers, 7.1 percent of commercial customers had switched providers, and 18.1 percent of industrial customers had switched providers.

In Pennsylvania, approximately 400,000 customers have switched providers, which represents a larger proportion of total customers than switched providers in California. In Rhode Island and Massachusetts, few customers have yet switched providers.

In large part, this small number reflects the rules set out in the transition.

The National Conference of State Legislatures notes that many utilities are selling their power plants. Only one state, Maine, has required the sale of all utilities' power plants, while some states have created incentives for utilities to sell their plants. With a few exceptions, these plants have sold for about double their book value, which is a far higher sales price than had been expected. Utilities have also been merging at speeds unprecedented for the industry as they attempt to cut costs and extend their markets.

Utilities generally have been allowed to recover their stranded costs subject to certain restrictions. In general, the magnitude of these stranded costs has been smaller than the original estimates. The higher-than-expected prices that power plants fetched on the open market serve to reduce the total amount of utilities' stranded costs.

The National Conference of State Legislatures notes that green power markets are surprisingly strong. Green power refers to an electricity product distinguished by a contract tied to production of energy generated from wind, biomass, geothermal, solar, or possibly hydro facilities. More than one-half of the customers in California have chosen a green power product and close to one-third of Pennsylvania's customers have chosen a green power product.

Most states that have enacted restructuring legislation include requirements that power marketers disclose the price, terms, fuel source, and emissions characteristics of the power sold to customers. Although states use a variety of approaches to this effort, it appears it is technically feasible to track the emissions characteristics of the power generated through the flow of contract dollars.

Almost every state that has passed comprehensive restructuring legislation has had to return the following year for revisions to the policy. In 1999 Nevada revised the dates for phasing in competition. Illinois and Maine addressed environmental and renewable energy provisions, and Montana put in place an energy tax reform package necessitated by a competitive electric industry. Montana also enacted provisions to give smaller customers a means to participate in the competitive electricity market through a statewide cooperative.

Electric Utility Taxation in Other States

States that have enacted comprehensive electric utility taxation bills include Iowa and Montana.

Iowa

Iowa Code Chapter 437A generally replaces the current central property tax assessment procedures utilized by the Iowa Director of Revenue and Finance in valuing property of entities involved primarily in the production, delivery, and transmission of electricity and natural gas, with excise taxes on electricity and natural gas, and a statewide property tax on certain property of these entities. The Act generally took effect January 1, 1999, and is applicable to property tax assessment years beginning on or after January 1, 1999, and to replacement tax years beginning on or after January 1, 1999.

Chapter 437A imposes a replacement tax on the delivery of electricity to a consumer in Iowa. The replacement delivery tax is an amount equal to the number of kilowatt-hours delivered to consumers by the taxpayer within each electric competitive service area during the tax year multiplied by the electric replacement delivery tax rate for each competitive service area plus, if applicable, the number of kilowatt-hours delivered to consumers by the taxpayer within each electric competitive service area during the tax year multiplied by the electric transfer replacement tax rate for each electric competitive service area. The tax rate is calculated by the Iowa Director of Revenue and Finance. Municipal electric transfer replacement tax rates are to be calculated annually by the city council of each city located within an electric competitive service area served by a municipal utility as of January 1, 1998.

Chapter 437A imposes a replacement tax on the delivery of natural gas to a consumer within Iowa. The replacement delivery tax is an amount equal to the number of therms delivered to consumers by the taxpayer within each natural gas competitive service area during the tax year multiplied by the natural gas delivery tax rate for each competitive service area plus, if applicable, the number of therms of natural gas delivered to consumers by the taxpayer within each natural gas competitive service area during the tax year multiplied by the municipal natural gas transfer replacement tax rate for each natural gas competitive service area. The tax rate is calculated by the Iowa Director of Revenue and Finance. Municipal natural gas transfer replacement tax rates are to be calculated annually by the city council of each city located within a natural gas competitive service area served by a municipal utility as of January 1, 1998.

Chapter 437A provides for the allocation of all replacement tax revenue by the Iowa Director of Revenue and Finance. All replacement taxes owed by a taxpayer are to be allocated among the local taxing districts in which the taxpayer's property is located in accordance with a general allocation formula determined by the Iowa Department of Management on the basis of general property tax equivalents.

Chapter 437A imposes an annual statewide property tax of three cents per $1,000 of assessed value on all property that is primarily and directly used in the production, generation, transmission, or delivery of electricity or natural gas owned or leased to a person subject to taxation under the chapter.

Montana

The Montana Electrical Generation Tax Reform Act, enacted in 1999, generally revised taxation of electric utilities in Montana. The Act became effective January 1, 2000. All investor-owned electric utility generation facilities were transferred from Class 9, 12 percent, to a new Class 13 and taxed at six percent of their market value on January 1, 2000, except for electrical generation facilities used for noncommercial purposes, exclusively for agricultural purposes, or qualifying as small power production facilities. The assessed value for the electrical facility's property remaining in Class 9 is not greater in fiscal year 2000 or fiscal year 2001 than the assessed value in 1998. The wholesale energy transaction tax applies to kilowatts per hour of electricity produced or consumed in Montana. The tax is applied to electrical transmission at the rate of 0.015 cents per kilowatt-hour.

Exemptions to the wholesale energy transaction tax include electricity that is transmitted through the state that is neither produced nor consumed in the state; electricity generated in the state by an agency of the federal government for delivery outside the state; electricity delivered to a distribution services provider that is a municipal utility or a rural electric cooperative; electricity delivered to a purchaser that receives its power directly from a transmission or distribution facility owned by an entity of the United States government on or before May 2, 1997, or electricity that is transmitted exclusively on transmission or distribution facilities owned by an entity of the United States government on or before May 2, 1997; electricity meeting certain contractual requirements that is delivered by a distribution services provider that was first served by a public utility after December 31, 1996; and electricity that has been subject to the transmission tax in another state. The tax is deposited in the state general fund.

Reimbursements are distributed on a semiannual basis to the county treasurer in the counties affected by a reduction in electric generation of property taxes. Distributions are based on each jurisdiction's change in assessed value of electric generation facilities and its previous year's mill levy.

Federal Restructuring Initiatives

Nine bills relating to electric industry restructuring were introduced during the 105th Congress. However, none became law. At least 14 bills relating to electric industry restructuring have been introduced in the 106th Congress; however, some deal with taxation and other issues and only relate tangentially to electric industry restructuring.

S.282 - This bill, the Transition to Competition in the Electric Industry Act, provides that no electric utility may be required, under the Public Utility Regulatory Policy Act of 1978, to enter a new contract or obligation to purchase or sell electricity or capacity from or to qualifying cogeneration and small power production facilities. The bill requires the Federal Energy Regulatory Commission to adopt regulations to ensure that no electric utility may be required to absorb the costs associated with purchases of electric power or capacity from a qualifying facility pursuant to the Public Utility Regulatory Policy Act obligations before enactment of the bill.

S.313 - This bill, the Public Utility Holding Company Act of 1999, would repeal the Public Utility Holding Company Act of 1935. The bill prescribes procedural guidelines for both the Federal Energy Regulatory Commission and state access to records of a holding company, including subsidiaries, associates, and affiliates, of a public utility or natural gas company. The bill subjects production of records to such terms and conditions as may be necessary and appropriate to safeguard against unwarranted disclosure to the public of trade secrets or sensitive commercial information. The bill requires the Federal Energy Regulatory Commission to exempt any person or transaction from these access requirements if it finds the regulation of that person or transaction is irrelevant to the jurisdictional rates of a public utility or natural gas company.

S.386 and H.R.721 - These bills, each known as the Bond Fairness and Protection Act of 1999, amend the Internal Revenue Code with respect to tax-exempt bond financing of certain electric facilities to exclude a permitted open access transaction from the definition of private business use. The bills permit termination of tax-exempt bond financing for certain electric output facilities.

S.516 - This bill, the Electric Utility Restructuring Empowerment and Competitiveness Act of 1999, amends the Federal Power Act to prescribe parameters within which a state may exercise jurisdiction over retail electric supplier distribution service provided to retail customers within its borders; establish and enforce electric energy performance standards; exercise authority over retail transactions, including the imposition of surcharges; and require electric energy suppliers to provide wholesale and retail reciprocity with respect to open, nondiscriminatory transmission access and local distribution access.

S.1047 - This bill, the Comprehensive Electricity Competition Act, provides that not later than January 1, 2003, any distribution utility that has the capability to deliver electric energy to an electric consumer over its facilities must offer open access to those facilities for the sale of electric energy to the consumer and must do so at rates, terms, and conditions that are not unduly discriminatory or preferential, as determined by the appropriate regulatory authority. State regulatory authorities and nonregulated distribution utilities may opt out of retail competition if the state regulatory authority finds that implementation of the retail competition requirement by a distribution utility will have a negative impact on a class of customers of that utility that cannot be mitigated, and a nonregulated distribution utility may determine not to implement the retail competition requirement if it finds, after notice and opportunity for hearing, that implementation of the retail competition requirement by the distribution utility will have a negative impact on a class of customers of that utility that cannot be mitigated.

S.1048 - This bill contains the tax provisions that accompany the Comprehensive Electricity Competition Act.

H.R.667 - This bill, the Power Bill, amends the Federal Power Act to declare that its prohibition against mandatory retail wheeling and sham wholesale transactions does not affect any state or local government authority under state law with respect to electric energy sale or transmission directly to an ultimate consumer. The bill prescribes guidelines for state-imposed reciprocity governing access to electric utility transmission distribution facilities. The bill grants cooperatively owned sellers or distributors of electricity the right to engage in any activity or provide any service lawfully carried out by any other seller or distributor of electricity in that state. The bill authorizes a state or state regulatory authority to impose charges upon purchases of retail electric energy services, including fees to recover costs incurred by an electric utility that become unrecoverable due to the availability of retail electric service choice, and to pay all reasonable costs associated with government requirements regarding decommissioning of nuclear generating units. The bill declares that, as of the date of enactment, new electric utility contracts for purchase or sale are not subject to specified requirements encouraging cogeneration and small power production. The bill also repeals the Public Utility Holding Company Act of 1935 and also prescribes guidelines for federal and state access to books and records of electric utility holding companies and their affiliates. The bill requires state laws or regulations for the recovery of stranded costs to be filed with the Federal Energy Regulatory Commission as a prerequisite to state receipt of federal energy assistance. The bill precludes any modification or repeal of these laws or regulations for seven years after their filing date and directs the Federal Energy Regulatory Commission to make these laws or regulations available to the public.

H.R.971 - This bill, the Electric Power Consumer Rate Relief Act of 1999, amends the Public Utility Regulatory Policy Act of 1978 to provide that a state regulatory authority may ensure that rates charged by qualifying small power producers and qualifying cogenerators to purchasing electric utilities are just and reasonable to consumers of the purchasing utility and in the public interest and do not exceed the incremental cost at the time of delivery to the utility of alternative electric energy and capacity.

H.R.1138 - This bill, the Ratepayer Protection Act, declares that no electric utility may be required to enter a new contract or obligation to purchase or sell electric energy or capacity pursuant to the provisions of the Public Utility Regulatory Policy Act of 1978 governing cogeneration and small power production. The bill directs the Federal Energy Regulatory Commission to adopt regulations to ensure that no utility may be required to absorb the costs associated with electric energy or capacity purchases from a qualifying facility executed before the Act's enactment date.

H.R.1486 - This bill, the Power Marketing Administration Reform Act of 1999, requires the Secretary of Energy to implement procedures to ensure that the federal power marketing administrations utilize the same accounting principles and requirements as the Federal Energy Regulatory Commission applies to the electric operations of public utilities.

H.R.1587 - This bill, the Electric Energy Empowerment Act of 1999, amends the Federal Power Act to empower the states to order electric utilities within their jurisdictions to provide nondiscriminatory open access through functionally unbundled transmission and local distribution services to retail customers within their borders (retail wheeling).

H.R.2645 - This bill, the Electricity Consumer, Worker, and Environmental Protection Act of 1999, implements federal and state standards for electricity service designed to protect workers in the electricity industry.

H.R.2734 - This bill, the Community Choice for Electricity Act of 1999, allows a group of customers or entities to acquire retail electric energy on an aggregate basis if the group is served by one or more local distribution companies that are subject to retail competition.

Testimony and Committee Activities

The committee determined that before it could recommend a comprehensive restructuring or deregulation proposal, it would need to address the taxation of the electric utility industry in North Dakota. The committee solicited and received proposals from the Association of Rural Electric Cooperatives and the state's investor-owned utilities and also developed its own proposals. All the proposals separated the generation function, transmission function, and distribution function for taxation purposes.

The initial proposal submitted by the Association of Rural Electric Cooperatives left in place the current coal conversion and coal severance taxes. The coal conversion tax is a privilege tax imposed on the operator of a coal conversion facility, which is defined to include any coal-fired electric generating unit with a capacity of 120 megawatts or more. It is a tax in lieu of a property tax on the plant itself but not on the land, which remains subject to a property tax. The tax is one-quarter mill times 60 percent of installed capacity times the number of hours in the taxable period and one-quarter mill per kilowatt-hour of electricity produced for sale. The coal severance tax is a tax on the removal of coal from the ground. The tax is applied at a rate of 75 cents per ton, with an additional two cents per ton for the lignite research fund.

The initial proposal taxed all transmission facilities on a line mile basis. Transmission lines under 75 kilovolts would be taxed at a rate of $100 per mile; transmission lines from 75 to 149 kilovolts would be taxed at a rate of $200 per mile; transmission lines from 150 to 224 kilovolts would be taxed at a rate of $300 per mile; transmission lines from 225 to 299 kilovolts would be taxed at a rate of $400 per mile; and transmission lines of 300 kilovolts or more would be taxed at a rate of $500 per mile.

Concerning the distribution function, utilities would be charged a tax on the distribution of electricity using a two-part formula. A flat tax of 62 cents per megawatt-hour of delivered power and a tax of one percent of revenue collected on the retail sale of kilowatt-hours of electricity. This taxation proposal would replace gross receipts and transmission line taxes paid by rural electric cooperatives and property taxes paid by investor-owned utilities.

Proponents of the proposal testified that the proposal would create an equitable electric utility tax structure and prepare the state and its political subdivisions for any changes in the electric utility industry or corporate structures that might occur in the future. Proponents testified that the proposal was designed to be revenue neutral with respect to the total taxes currently paid to political subdivisions by the electric utility industry in North Dakota. Current generation taxes generate approximately $12 million annually, and transmission and distribution taxes generate approximately $11.6 million per year. Although the proposal was not intended to be revenue neutral with respect to the taxes paid by individual utilities, and under the proposal some utilities would pay more than previously and some would pay less, proponents testified that all are treated fairly and uniformly with respect to property taxation within each utility function.

Proponents testified that generation taxes would be imposed separately from taxes on transmission and distribution. To a large extent, this is already the case as the coal conversion tax serves as an in lieu of property tax on all coal-fired generation facilities of 120 megawatts or more. At 86 megawatts, the Heskett Plant owned by Montana-Dakota Utilities Company is not subject to the coal conversion tax. Instead, the value of this facility is currently included as part of Montana-Dakota Utilities Company's centrally assessed property. Other electric generation in the state is standby, peaking, or self-generation that is subject to local property taxation but would not be assessed on a systemwide basis as is presently the case for the investor-owned utilities.

Concerning the transmission function, transmission facilities currently are taxed in three ways. First, investor-owned utility transmission lines are centrally assessed as part of each utility's systemwide property tax assessment. Second, rural electric cooperative generation and transmission companies pay gross receipts taxes. Third, rural electric cooperative generation and transmission companies pay a tax of $225 per mile on all transmission lines of 230 kilovolts or higher. Under the Association of Rural Electric Cooperatives' initial proposal, taxes on the transmission function would generate approximately $1,975,000. In addition, utilities would continue to pay a locally assessed property tax on land owned by them for their substations.

Concerning the distribution function, to maintain overall revenue neutrality to the political subdivisions in the Association of Rural Electric Cooperatives' initial proposal, the distribution tax would have to generate approximately $9.6 million per year. Investor-owned utility distribution facilities are centrally assessed on a systemwide basis while rural electric cooperatives pay a combination of taxes, including a gross receipts tax, a land tax, and an optional city privilege tax. Under the Association of Rural Electric Cooperatives' initial proposal, all these taxes, except for a locally assessed land tax that would be paid by all utilities, would be replaced with a distribution tax consisting of two components, each of which would generate approximately $4.8 million in revenue annually. The first component was a flat tax of $.00062 per kilowatt per hour or $.62 per megawatt-hour sold at retail. The second component was a one percent tax on revenue from the retail sale of electricity or electric-operating revenue.

Proponents testified that the two-component distribution tax would balance opposing views on how distribution taxes should be allocated among consumer classes. One view holds that each kilowatt-hour should be taxed the same for use of the distribution system. The other view holds that high-volume or offpeak energy users who receive volume discounts or price concessions to encourage usage should pay a lesser proportionate share of distribution taxes. Proponents testified that relying exclusively on a flat tax per kilowatt-hour generally benefits utilities that sell smaller amounts of energy at higher prices, whereas imposition of a tax based on a percentage of retail sales benefits utilities that sell a high volume of energy at lower prices. Because there can be substantially different tax consequences by moving exclusively to one tax or the other, proponents testified that the proposal adopted both approaches as a compromise solution pending further study and additional information regarding how the industry might change in the future.

Concerning revenue distribution, the initial proposal did not specifically address the long-term distribution or redistribution of revenue among political subdivisions but guaranteed a minimum level of revenue for each county based upon previous tax collections in the base years 1995 through 1997. The proposed taxes would be applicable to all utilities and other entities owning generation, transmission, or distribution facilities in the state, including municipal utilities. The property taxes would be embedded in the rates charged by utilities for wheeling power over transmission or distribution lines, so they would be a nonbypassable tariff on power marketers.

Concerning the impact of this electric utility taxation proposal, proponents testified that the proposal affected utilities differently depending upon their current tax burdens, their ownership of transmission facilities, and the volume and price of their electric energy sales. The committee received testimony that overall the plan would impose additional taxes of about $88,000 on distribution cooperatives and would cost Basin Electric Power Cooperative and Great River Energy and Central Power Cooperative more than $100,000 each. Xcel Energy, Inc., would pay more than $500,000 in additional taxes, and Montana-Dakota Utilities Company would pay over $400,000 more. Otter Tail Power Company would pay slightly less tax than it currently pays. Under this initial proposal, Central Power and Upper Missouri Generation and Transmission, both of which are intermediate transmission cooperatives, would realize substantial savings. This is due to the elimination of the "pancaking" effect of the two percent gross receipts tax. Under current law, when a transmission cooperative sells power to its distribution members, it must pay a two percent gross receipts tax on the revenue it receives from these sales. When the distribution cooperative resells the same electric energy, the distribution cooperative also pays a two percent gross receipts tax on selected sales.

Opponents testified that the Association of Rural Electric Cooperatives' initial proposal did not address the approximately $2.5 million paid in state income taxes by the state's investor-owned utilities. Opponents testified that the percentage of retail sales tax component of the proposal added complexity to the taxation scheme, shifted costs among consumers, and could produce negative results in terms of revenue erosion in a restructured market. Opponents testified that they favored a megawatt per hour tax. Concerning taxation of the transmission component, opponents testified that the transmission proposal did not tax these assets at an appropriate level. They testified that the initial proposal shifted a disproportionate proportion of the tax to the distribution component in favor of the transmission component, and they indicated that a better balance is possible. Finally, opponents testified that the initial proposal did not address current and future power marketers.

The state's investor-owned utilities submitted an electric utility industry taxation proposal that taxed the generation component, transmission component, and distribution component by function. Concerning the generation component, the proposal taxed all generation plants in the state based on the current coal conversion formula. This would include Montana-Dakota Utilities Company's Heskett Plant and various small peaking plants. Proponents indicated that taxing all generation plants would allow all current and future power plants to compete with one another without regard to taxes and tax policy.

Concerning the transmission component, the proposal taxed all transmission facilities on a line mile basis. Transmission lines of 41.6 kilovolts would be taxed at a rate of $200 per mile; transmission lines of 57 kilovolts would be taxed at a rate of $300 per mile; transmission lines of 69 kilovolts would be taxed at a rate of $500 per mile; transmission lines of 115 kilovolts would be taxed at a rate of $600 per mile; transmission lines of 230 kilovolts would be taxed at a rate of $800 per mile; transmission lines of 345 kilovolts would be taxed at a rate of $1,000 per mile; and transmission lines of 400 kilovolts would be taxed at a rate of $1,200 per mile.

Concerning the distribution component, utilities would be charged a distribution tax of $1.5255 per megawatt-hour for residential and other classes of customers and $.9153 per megawatt-hour for commercial and industrial customers. This component also included a power marketer tax of $.4416 per megawatt-hour. The proposal replaced gross receipts and transmission line taxes paid by rural electric cooperatives, property taxes paid by investor-owned utilities, and state income taxes paid by investor-owned utilities. Proponents testified that the entire distribution component should be based on a rate per megawatt-hour. They indicated it would be included in the ratemaking process as an embedded cost and thus would preclude tax-exempt organizations and out-of-state power marketers that sell to in-state customers from bypassing the tax. The rate per megawatt-hour would be designed for classes of customers based on cost of service. To minimize customer class subsidization, the rate for the residential and other class would be higher than the rate for the commercial and industrial class. The commercial and industrial class rate would be 60 percent of the residential class rate. Proponents testified that a different rate for different classes of customers is appropriate and consistent with current class cost-of-service studies on file with the Public Service Commission. Representatives of the state's investor-owned utilities testified that their proposal would provide the required stable revenue stream to the state, would allow for the benefits of a competitive electric market to not be influenced by taxation rates and policy, would be relatively simple and easy to administer, would pass nexus requirements and interstate commerce concerns, would allow for state revenue growth, and would meet the needs of the state and all the electric consumers in the state.

Opponents of the proposal submitted by the state's investor-owned utilities testified that adoption of the transmission component would be devastating for the state's rural electric cooperatives, and a percentage of revenue tax may lead to revenue increases if electric utility rates increase in a deregulated market.

The Association of Rural Electric Cooperatives submitted a revised electric utility industry taxation proposal. This proposal also retained the state's coal conversion and coal severance taxes but extended the coal conversion tax to all generation facilities of five megawatts or greater regardless of fuel source. This proposal taxed all transmission facilities on a line mile basis. Transmission lines under 50 kilovolts would be taxed at a rate of $75 per mile; transmission lines from 50 to 99 kilovolts would be taxed at a rate of $150 per mile; transmission lines from 100 to 199 kilovolts would be taxed at a rate of $300 per mile; transmission lines from 200 to 299 kilovolts would be taxed at a rate of $450 per mile; transmission lines from 300 to 399 kilovolts would be taxed at a rate of $600 per mile; and transmission lines of 400 kilovolts or more would be taxed at a rate of $900 per mile. Concerning the distribution component, utilities would be charged a tax on the distribution of electricity using a two-part formula--a flat tax of 59 cents per megawatt-hour of delivered power and a tax of .95 percent of revenue collected on the retail sale of kilowatt-hours of electricity. The association's revised proposal increased transmission taxes $400,000 or 20 percent over its initial proposal and reduced the distribution tax component accordingly.

Opponents of this revised proposal testified that a distribution formula that does not separate residential from commercial and industrial users would increase the cost of electricity significantly for commercial and industrial users which would harm economic development in the state. Proponents countered that the revised proposal accounted for both the low-cost and high-cost energy and the high-volume and the low-volume energy user and would have a minimal impact on individual energy users and not harm economic development in the state.

In addition to the transmission taxation proposals contained in the two proposals submitted by the Association of Rural Electric Cooperatives and the proposal submitted by the state's investor-owned utilities, the committee developed two transmission tax alternatives. Under the committee's initial proposal, transmission lines under 50 kilovolts would be taxed at a rate of $125 per mile; transmission lines from 50 to 99 kilovolts would be taxed at a rate of $300 per mile; transmission lines from 100 to 199 kilovolts would be taxed at a rate of $500 per mile; transmission lines from 200 to 299 kilovolts would be taxed at a rate of $700 per mile; transmission lines from 300 to 399 kilovolts would be taxed at a rate of $900 per mile; and transmission lines of 400 kilovolts or more would be taxed at a rate of $1,200 per mile.

Under current law, lines of 230 kilovolts or larger are taxed at a rate of $225 per mile. There are 1,824.8 miles of transmission lines in this category which generate $410,580 annually. The transmission component of the Association of Rural Electric Cooperatives' initial proposal would raise $1,968,538, the transmission component of the Association of Rural Electric Cooperatives' revised proposal would raise $2,388,362.20, the transmission component of the state's investor-owned utilities' proposal would raise $4,943,192, and the committee's initial proposal would raise $3,884,387.70. Under the second transmission taxation formula developed by the committee, transmission lines of 41.6 kilovolts would be taxed at a rate of $200 per mile, transmission lines of 57 kilovolts would be taxed at a rate of $300 per mile, transmission lines of 69 kilovolts would be taxed at a rate of $400 per mile, transmission lines of 115 kilovolts would be taxed at a rate of $600 per mile, transmission lines of 230 kilovolts would be taxed at a rate of $800 per mile, transmission lines of 345 kilovolts would be taxed at a rate of $1,000 per mile, and transmission lines of 400 kilovolts would be taxed at a rate of $1,500 per mile. This proposal also included a tax of $1,300 per mile on transmission lines of 500 kilovolts, a tax of $1,200 per mile on 250 kilovolt direct current lines, and a tax of $1,500 per mile on 400 direct current lines.

Representatives of the state's investor-owned utilities testified that both of the Association of Rural Electric Cooperative proposals would have a negative impact on their customers. They testified that the initial Association of Rural Electric Cooperative proposal would shift approximately $1 million from the generation and transmission cooperatives to the investor-owned utilities and that the distribution tax component could lead to state revenue erosion. Under the revised proposal, representatives of the state's investor-owned utilities testified that $700,000 would be shifted to the state's investor-owned utilities. Also, they testified, neither proposal addressed the state income taxes paid by the investor-owned utilities.

Concerning the investor-owned utilities' proposal, representatives of the Association of Rural Electric Cooperatives testified that the investor-owned utility proposal would increase the amount of revenue generated by transmission and distribution taxes by an additional $2.5 million in order to offset a 100 percent income tax credit for the investor-owned utilities. They testified that this would have the effect of making rural electric cooperative customers share the burden of the investor-owned utilities' state income tax liability without receiving the benefits of the investor-owned utility profits that are largely realized by out-of-state shareholder-investors. Representatives of the Association of Rural Electric Cooperatives testified that the investor-owned utility proposal would place a disproportionate share of the tax burden on the transmission system in comparison to the distribution system. They testified that this feature of the investor-owned utility proposal is designed to place a greater burden on the rural electric cooperatives because they own more transmission in the state, especially high-voltage transmission, than do the investor-owned utilities. Representatives of the Association of Rural Electric Cooperatives also testified that the distribution component of the investor-owned utility proposal favored a low tax rate on all electrical sales to commercial and industrial customers and a high rate for residential customers, even those who use low-cost, offpeak electricity for home heating. They noted that the rural electric cooperatives serve, on average, a smaller percentage of commercial and industrial customers and a higher percentage of residential accounts than do the state's investor-owned utilities, and the investor-owned utility tax proposal's rates were calculated to shift more of the distribution tax burden to the rural electric cooperatives.

The committee also received information from the State Tax Department on the dollar amounts of property taxes, gross receipts, and transmission line taxes levied against electric companies in North Dakota for the years 1995 through 1999. The amount of tax levied was $11,694,190.68 in 1995, $11,947,394.07 in 1996, $12,658,617.81 in 1997, $12,590,293.23 in 1998, and $12,141,287.23 in 1999. The five-year average is $12,206,356.60.

Committee Considerations

The committee considered a bill draft relating to taxation of the distribution and transmission of electric power for retail sale in North Dakota. The bill draft would have applied the state's coal conversion tax to Montana-Dakota Utilities Company's Heskett Plant in Mandan; removed investor-owned utility property from central assessment under NDCC Chapter 57-06; removed the gross receipts tax for rural electric cooperatives; imposed transmission and distribution line taxes in lieu of property taxes except that property taxes would still be imposed on land, office or administrative-type buildings, and buildings and structures not used primarily and directly in the delivery of electricity through transmission and distribution lines; subjected peaking plants of less than 80 megawatts to local property tax assessment or exempted them as property used primarily in the delivery of electricity through lines; increased the transmission line tax; imposed a distribution tax; excluded municipal electric utilities from coverage under the bill draft; and allocated transmission and distribution tax revenue with a continuing appropriation to political subdivisions.

The bill draft would have imposed an annual transmission line mile tax on transmission lines based on their nominal operating voltages on April 1 of each year. A tax of $200 would have been imposed on transmission lines that operate at a nominal operating alternating current voltage of less than 57 kilovolts; a tax of $300 would have been imposed on transmission lines that operate at a nominal operating alternating current voltage of 57 kilovolts or more, but less than 69 kilovolts; a tax of $400 would have been imposed on transmission lines that operate at a nominal operating alternating current voltage of 69 kilovolts or more, but less than 115 kilovolts; a tax of $600 would have been imposed on transmission lines that operate at a nominal operating alternating current voltage of 115 kilovolts or more, but less than 230 kilovolts; a tax of $800 would have been imposed on transmission lines that operate at a nominal operating alternating current voltage of 230 kilovolts or more, but less than 345 kilovolts; a tax of $1,000 would have been imposed on transmission lines that operate at a nominal operating alternating current voltage of 345 kilovolts or more, but less than 500 kilovolts; a tax of $1,200 would have been imposed on transmission lines that operate at a nominal operating direct current voltage of less than 400 kilovolts; a tax of $1,300 would be imposed on transmission lines that operate at a nominal operating alternating current voltage of 500 kilovolts or more; and a tax of $1,500 would have been imposed on transmission lines that operate at a nominal operating direct current voltage of 400 kilovolts or more.

Concerning distribution taxes, distribution companies would have been subject to a distribution tax of 75.83 cents per megawatt-hour for the retail sale of electricity to commercial or industrial consumers and a rate of $1.2638 per megawatt-hour for the retail sale of electricity to noncommercial or nonindustrial consumers. The bill draft included a continuing appropriation for allocation of electric transmission and distribution tax revenue to counties thus obviating the need for counties to approach the Legislative Assembly each session to appropriate the revenue from the electric transmission and distribution taxes to these political subdivisions. Revenue from the tax on transmission lines would have been allocated among counties based on the mileage of transmission lines and the rates of tax on those lines within each county. Revenue received by a county would have been allocated among taxing districts in the county based on the mileage of transmission lines and the rates of tax on those lines within each taxing district. Revenue from that portion of a transmission line located in more than one taxing district would have been allocated among those taxing districts in proportion to their respective current property tax mill rates that apply to the land on which the transmission line is located. Revenue from the distribution company tax would have been allocated to the county in which the retail sale to which the tax applied was made and allocated among taxing districts in the county in proportion to their respective property tax levies in dollars on property within the county in the previous taxable year. Cities that operate municipal electric utilities would have been excluded from allocations and computations under this provision.

The committee received testimony from representatives of the office of the State Tax Commissioner that the proposal should define "commercial or industrial customer" and would generate $12,220,462 versus the total of taxes levied on electric property under existing law, $12,575,382. The committee received testimony from representatives of the state's investor-owned utilities that the distribution tax component would generate $546,000 more in annual revenue than existing taxes, and the distribution tax rate should be set at $.6202 per megawatt-hour for commercial and industrial customers and $1.0337 per megawatt-hour for residential and other customers. Under the proposed distribution tax formula, they testified, rural electric cooperatives would average $1.1188 per megawatt-hour and generation and transmission cooperatives would average $.1104 per megawatt-hour for a total between these two of $1.2292. They testified that the average for investor-owned utilities would be $1.3887 per megawatt-hour, and the proposal did not include the $2.5 million in state income taxes paid by the state's investor-owned utilities which adds another $.06 per megawatt-hour to the bills of consumers served by investor-owned utilities. Also, they testified, the transmission line mile tax is too high and may discourage construction of a new coal-fired generating plant in North Dakota. Also, representatives of the state's investor-owned utilities testified that any tax restructuring legislation should be part of a comprehensive electric restructuring bill and should not be enacted before implementation of restructuring.

The committee received testimony from representatives of the state's rural electric cooperatives that the total amount of transmission taxes under the bill draft would exceed $4.9 million and would impact some transmission owners disproportionately. Representatives of the Association of Rural Electric Cooperatives testified that their revised proposal would result in less tax shifting among utilities than would occur under the bill draft. The maximum transmission and distribution tax increase for an investor-owned utility under the Association of Rural Electric Cooperatives' plan is approximately 25 percent, and overall investor-owned utility transmission and distribution taxes would increase approximately 13 percent. By contrast, Great River Energy's transmission taxes would increase by more than 400 percent, and Minnkota Electric Cooperative's transmission taxes would nearly double under the bill draft. They testified that their proposal does not rely on an arbitrary distinction between commercial and industrial sales and residential and other sales. Fifty percent of their distribution tax formula is based on a percentage of gross revenue which means there is less tax on high-volume, low-cost electric sales to commercial and industrial accounts, and the same tax benefit is provided to other low-cost users such as those who take advantage of offpeak electric heating programs. They testified that their revised proposal was easier to administer because it would not require the adoption, utilization, and enforcement of a common definition for commercial and industrial sales. They also testified that the tax rates contained in their proposal are more attuned to the economic realities of the electric utility industry in North Dakota than are the rates in the bill draft.

The committee considered a bill draft relating to electrical generating plants subject to the privilege tax on coal conversion facilities. This bill draft would have defined coal conversion facilities for purposes of the coal conversion tax as electrical generating plants, with all additions thereto, which use coal as a fuel source to generate electrical power and which have electrical energy generation capacity of 80,000 kilowatts or more. The effect of the bill draft would be to extend the coal conversion tax to Montana-Dakota Utilities Company's Heskett Plant in Mandan.

The committee received testimony that the bill draft would have a negative impact on tax revenue to Morton County and thus did not meet the committee's revenue neutrality goal.

Conclusion

The committee makes no recommendation concerning its study of the impact of competition on the generation, transmission, and distribution of electric energy within this state.

TERRITORIAL INTEGRITY ACT STUDY

The Territorial Integrity Act was enacted by the Legislative Assembly in 1965 and is codified as NDCC Sections 49-03-01 through 49-03-01.5. These sections provide:

> **49-03-01. Certificate of public convenience and necessity - Secured by electric public utility.** No electric public utility henceforth shall begin construction or operation of a public utility plant or system, or of an extension of a plant or system, except as provided below, without first obtaining from the commission a certificate that public convenience and necessity require or will require such construction and operation. This section does not require an electric public utility to secure a certificate for an extension within any municipality within which it has lawfully commenced operations. If any electric public utility in constructing or extending its line, plant, or system, unreasonably interferes with or is about to interfere unreasonably with the service or system of any other electric public utility, or any electric cooperative corporation, the commission, on complaint of the electric public utility or the electric cooperative corporation claiming to be injuriously affected, after notice and hearing as provided in this title, may order enforcement of this section with respect to the offending electric public utility and prescribe just and reasonable terms and conditions.
>
> **49-03-01.1. Limitation on electric transmission and distribution lines, extensions, and service by electric public utilities.** No electric public utility henceforth shall begin in the construction or operation of a public utility plant or system or extension thereof without first obtaining from the commission a certificate that public convenience and necessity require or will require such construction and operation, nor shall such public utility henceforth extend its electric transmission or distribution lines beyond or outside of the corporate limits of any municipality, nor shall it serve any customer where the place to be served is not located within the corporate limits of a municipality, unless and until, after application, such electric public utility has obtained an order from the commission authorizing such extension and service and a certificate that public convenience and necessity require that permission be given to extend such lines and to serve such customer.
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> **49-03-01.3. Exclusions from limitations on electric distribution lines, extension, and service and on issuance of certificates of public convenience and necessity.** Sections 49-03-01 through 49-03-01.5 shall not be construed to require any such electric public utility to secure such order or certificate for an extension of its electric distribution lines within the corporate limits of any municipality within which it has lawfully commenced operations; provided, however, that such extension or extensions shall not interfere with existing services provided by a rural electric cooperative or another electric public utility within such municipality; and provided duplication of services is not deemed unreasonable by the commission.
>
> Sections 49-03-01 through 49-03-01.5 shall not be construed to require an electric public utility to discontinue service to customers thereof whose places receiving service are located outside the corporate limits of a municipality on July 1, 1965; provided, however, that within ninety days after July 1, 1965, any electric public utility furnishing service to customers whose places receiving service are located outside the corporate limits of a municipality shall file with the commission a complete map or maps of its electric distribution system showing all places in North Dakota which are located outside the corporate limits of a municipality and which are receiving its service as of July 1, 1965. After ninety days from July 1, 1965, unless a customer whose place being served is located outside the corporate limits of a municipality is shown on said map or maps, it shall be conclusively presumed that such customer was not being served on July 1, 1965, and cannot be served until after compliance with the provisions of section 49-03-01.1.
>
> **49-03-01.4. Enforcement of act.** If any electric public utility violates or threatens to violate any of the provisions of

sections 49-03-01 through 49-03-01.5 or interferes with or threatens to interfere with the service or system of any other electric public utility or rural electric cooperative, the commission, after complaint, notice, and hearing as provided in chapter 28-32, shall make its order restraining and enjoining said electric public utility from constructing or extending its interfering lines, plant, or system. In addition to the restraint imposed, the commission shall prescribe such terms and conditions as it shall deem reasonable and proper.

Provided, further, that nothing herein contained shall be construed to prohibit or limit any person, who has been injured in the person's business or property by reason of a violation of sections 49-03-01 through 49-03-01.5 by any electric public utility or electric cooperative corporation, from bringing an action for damages in any district court of this state to recover such damages.

49-03-01.5. Definitions. As used in sections 49-03-01 through 49-03-01.5:

1. "Electric public utility" means a privately owned supplier of electricity offering to supply or supplying electricity to the general public.
2. "Person" includes an individual, an electric public utility, a corporation, a limited liability company, an association, or a rural electric cooperative.
3. "Rural electric cooperative" includes any electric cooperative organized under chapter 10-13. An electric cooperative, composed of members as prescribed by law, shall not be deemed to be an electric public utility.

As enacted, the Territorial Integrity Act included a section that provided:

> The public service commission of the state of North Dakota shall not issue its order or its certificate of public convenience and necessity to any electric public utility to extend its electric distribution lines beyond the corporate limits of a municipality or to serve a customer whose place to be served is located outside the corporate limits of a municipality unless the electric cooperative corporation with lines or facilities nearest the place where service is required shall consent in writing to such extension by such electric public utility, or unless, upon hearing before the commission, called upon notice, shall be shown that the service required cannot be provided by an electric cooperative corporation. Such certificate shall not be necessary if the public service commission approves an agreement between a public utility and a rural electric cooperative serving the area which includes the station to be served in which agreement designates said station to be in an area to be served by the public utility.

In *Montana-Dakota Utilities Co. v. Johanneson*, 153 N.W.2d 414 (N.D. 1967), the North Dakota Supreme Court declared this section to be an unconstitutional delegation of legislative authority.

Although the legislative history of the Territorial Integrity Act is extensive, the rationale for its enactment was summarized in *Capital Electric Cooperative Inc. v. Public Service Commission*, 534 N.W.2d 587 (N.D. 1995). In this case, it was noted that "the Act was adopted at the request of the North Dakota Association of Rural Electric Cooperatives to provide 'territorial protection' for rural electric cooperatives and to prevent public utilities from 'pirating' rural areas," and the "primary purpose of the Act was to minimize conflicts between suppliers of electricity and wasteful duplication of investment in capital-intensive utility facilities." In *Capital Electric,* the North Dakota Supreme Court established a requirement that a request by a new customer for electric service from a public utility must be made before the Public Service Commission may consider whether to issue a certificate of public convenience and necessity to the utility.

The Territorial Integrity Act basically allowed cooperatives to extend service in rural areas and public utilities to extend service in municipal areas without first obtaining a certificate of public convenience and necessity from the Public Service Commission, the theory being that the delineation of service areas would allow each type of enterprise to expand within its own sphere without conflict with each other. Problems arose, however, as the public utility companies believed that by being confined to municipal areas except as provided in the Act, they were being denied a fair share of the business arising in the rural "growth" areas. This objection to the effect of the Territorial Integrity Act resulted in *Montana-Dakota Utilities Co. v. Johanneson*, which squarely attacked its constitutionality. In *Johanneson*, the public utility companies took the position the law was an unconstitutional classification for several reasons. They contended cooperatives were given a monopoly in rural areas and were allowed to operate without Public Service Commission regulation, while the public utilities were regulated in every respect by that agency. They claimed that cooperatives could infringe on the existing service areas of public utility companies in rural localities and that new customers could be gained in municipal areas only if there was no interference with cooperative services already provided in the municipality. They also asserted cooperatives had a right to complain against public utilities' actions, but the utilities had no such right against actions of the cooperatives. Thus, they maintained the Territorial Integrity Act was unfair, arbitrary, and unreasonable, and the Act discriminated against the public utility companies and the public generally.

The North Dakota Supreme Court in *Johanneson* upheld the constitutionality of the Act in all but one respect. It held that although the Act treated public utilities and cooperatives dissimilarly, the classification was not objectionable as it was based on legally justifiable distinctions. While public utilities were denied the right under the Act to complain of improper actions by cooperatives, the right remained to bring an action in the courts of the state for redress of any injury that might be suffered. Thus, the public utilities did have an adequate remedy and were not prejudiced.

However, the court found otherwise with regard to Section 3 of the Act (NDCC Section 49-03-01.2) which conditioned the issuance of certificates of public convenience and necessity on the written consent of the nearest cooperative, or upon a finding a cooperative could not provide the service. Here, the court found that it was "the cooperative, and not the public service commission . . . that determines whether a certificate of public convenience and necessity shall be granted to a public utility in the area outside the limits of the municipality" and that "[n]o guidelines are set out in the law to be followed by the cooperative in making such determination, and no safeguards are provided against arbitrary action . . . ." Thus, the court held that where "the Act attempts to delegate, to either the Public Service Commission or the cooperative, powers and functions which determine such policy and which fix the principles which are to control, the Act is unconstitutional." Likewise, the court found that the portion of the Act that permitted supplying of service without certificates if a "consent" agreement was entered by the cooperative and public utility as to service areas also was unconstitutional, as again the cooperative was permitted to determine whether a certificate should be granted.

The impact of *Johanneson* immediately became evident. Because the provisions of the Territorial Integrity Act allowing for "consent" agreements in lieu of certificates of public convenience and necessity were declared unconstitutional, it was apparent the caseload of the commission and the issuance of certificates would increase substantially. In anticipation of this increase and to reduce the delay caused by the notices and hearings necessary for the issuance of certificates, the Public Service Commission requested an opinion of the Attorney General as to whether conditional certificates could be issued without the usual full-scale hearing and determination. The Attorney General, in an opinion dated October 30, 1967, declared that the issuing of conditional certificates without hearing was proper, provided the controversy was fully submitted to the commission by an interested party in such a manner so a decision could be made, and the parties waived the notice and hearing required in the issuance of a certificate of public convenience and necessity. Thus, the issuing of temporary certificates under certain conditions was allowed.

When NDCC Section 49-03-01.2 was declared unconstitutional, the legislative directions to the Public Service Commission were eliminated, and no criteria upon which the commission could make its decisions remained. However, this deficiency was remedied by the court in *Application of Otter Tail Power Co.*, 169 N.W.2d 415, 418 (N.D. 1969), in which the court established that in addition to customer preference, factors to be considered in determining whether an application for a certificate of public convenience and necessity should be granted include "the location of the lines of the supplier; the reliability of the service which will be rendered by them; which of the proposed suppliers will be able to serve the area more economically and still earn an adequate return on its investment; and which supplier is best qualified to furnish electric service to the site designated in the application and which also can best develop electric service in the area in which such site is located without wasteful duplication of investment service." Thus, customer preference is not a controlling factor but only one of a number of factors that must be considered for a certificate of public convenience and necessity to be granted.

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 where 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 *Johanneson*. The cooperatives maintained any change in the law would result in considerable expense to cooperative 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 as 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 provide a return to their stockholders, they must also continue to grow, and the only area where growth was possible was in the metropolitan fringe areas. The committee made no recommendation as a result of this study.

1997-98 Study

In conducting its study of the impact of competition on the generation, transmission, and distribution of electric energy within this state, the 1997-98 interim 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 it is a barrier to giving customers throughout the state the ability to make economic energy choices and as such should be repealed and fair play 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 no longer qualify for favorable financing arrangements with the federal government, exemption from state and federal income taxes, preferential access to low-priced federal power, and potential for debt forgiveness by the Rural Utilities Service, and should be subject to the same regulatory overview as public utilities.

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. The committee received testimony 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 in the rural areas and a corresponding decline in electrical usage. They testified that 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 it makes no sense to expand investor-owned utility territorial growth at the expense of the rural electric cooperatives that have invested in rural North Dakota. Representatives of the rural electric cooperatives responded to the charge investor-owned utilities are competitively disadvantaged by the Territorial Integrity Act by testifying 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.

Representatives of the rural electric cooperatives also argued that the Territorial Integrity Act is not responsible for rural electric cooperative expansion into urban areas; that rural electric cooperatives can continue to serve their traditional service areas even when these areas become urbanized; and that the growth of the local rural electric cooperative around Fargo is overstated. The committee made no recommendation as a result of this study.

1999 Proposed Legislation

Senate Bill No. 2389 (1999), as introduced, would have revised the Territorial Integrity Act. The bill provided that after July 31, 1999, an electric public utility, if authorized by franchise, is to provide electric service to all customers within the corporate limits of a municipality, except that a rural electric cooperative could continue to provide service to electric customers it was serving within a municipality on July 31, 1999, if allowed by the municipality. The bill provided that a rural electric cooperative could not provide electric service to any new customer within the corporate limits of the municipality after July 31, 1999. If a municipality did not allow a rural electric cooperative to continue electric service to existing customers within the municipality, the rural electric cooperative could remove its lines, plant, or system or sell its lines, plant, or system to the franchised electric public utility. The bill also brought rural electric cooperatives under the enforcement provisions of the Territorial Integrity Act and allowed the selling or trading of facilities or customers upon agreement between a rural electric cooperative and an electric public utility, subject to the approval of the city if sales or trades were made within the city or subject to the approval of the Public Service Commission if outside the corporate limits of a municipality. This bill was substantially amended to remove changes to the state's Territorial Integrity Act and as enacted called for the study of the state's Territorial Integrity Act.

Exclusive Electric Service Area Laws of Surrounding States South Dakota

South Dakota Codified Laws Sections 49-34A-42 through 49-34A-44 and Sections 49-34A-48 through 49-34A-59 govern exclusive electric service areas in that state. Each electric utility has the exclusive right to provide electric service at retail at each location where it served a customer on March 21, 1975, and to each present and future customer in its assigned service area. An electric utility cannot render or extend electric service at retail within the assigned service area of another electric utility without the other electric utility's consent and without approval by the South Dakota Public Utilities Commission. An electric utility can extend its facilities to the assigned service area of another electric utility, however, if the extension is necessary to facilitate the electric utility connecting its facilities or customers within its own assigned service area.

The boundaries of each assigned service area, outside incorporated municipalities, are a line equidistant between the electric lines of adjacent electric utilities as they existed on March 21, 1975, provided that these boundaries may be modified by the South Dakota Public Utilities Commission to take account of natural and other physical barriers that would make service of electric power and energy beyond those barriers economically impracticable and must be modified to take into account existing contracts or to take into account orders entered before July 1, 1975, by the Electric Mediation Board. If a single electric utility provided electric service within a municipality on March 21, 1975, the entire municipality constitutes a part of the assigned service area of that electric utility. If two or more electric utilities provided electric service in a municipality on March 21, 1975, the boundaries of the assigned service areas within the incorporated municipality must be assigned pursuant to the equal distance concept as applied to lines located only within the municipal boundaries.

Notwithstanding the establishment of assigned service areas for electric utilities, new customers at new locations that develop after March 21, 1975, located outside municipalities as the boundaries existed on March 21, 1975, and who require electric service with a contracted minimum demand of 2,000 kilowatts or more are not obligated to take electric service from the electric utility having the assigned service area where the customers are located if the South Dakota Public Utilities Commission determines after consideration of the following factors:

1. The electric service requirements of the load to be served.
2. The availability of an adequate power supply.
3. The development or improvement of the electric system of the utility seeking to provide the electric service, including the economic factors relating thereto.
4. The proximity of adequate facilities from which electric service of the type required may be delivered.
5. The preference of the consumer.
6. Any and all pertinent factors affecting the ability of the utility to furnish adequate electric service to fulfill the customer's requirements.

Minnesota

Minnesota Statutes Section 216B.37 provides that the state of Minnesota is divided into geographic service areas within which a specified electric utility is to provide electric service to customers on an exclusive basis. For purposes of the Minnesota exclusive electric service area law, the term "electric utility" includes facilities owned by a municipality or by a cooperative electric association.

Within six months from April 12, 1974, each electric utility was required to file with the Minnesota Public Utilities Commission a map showing all its electric lines outside incorporated municipalities and was required to submit a list of all municipalities in which it provided electric service on April 12, 1974. If two or more electric utilities served a single municipality, the commission could require each utility to file with the commission a map showing its electric lines within the municipality. Within 12 months from April 12, 1974, the commission established the assigned service area or areas of each electric utility and prepared a map to show the boundaries of the assigned service area of each electric utility. To the extent it was not inconsistent with the expressed legislative policy, the boundaries of each assigned service area, outside incorporated municipalities, was a line equidistant between electric lines of adjacent electric utilities as they existed on April 12, 1974.

Except as otherwise provided, each electric utility has the exclusive right to provide electric service at retail to each present and future customer in its assigned service area, and no electric utility may render or extend electric service at retail within the assigned service area of another electric utility unless the electric utility consents, but an electric utility can extend its facilities through the assigned service area of another electric utility if the extension is necessary to facilitate the electric utility connecting its facilities or customers within its own assigned service area. If a municipality owning and operating an electric utility extends its corporate boundaries through annexation or consolidation or determines to extend its service territory within its existing corporate boundaries, the municipality may purchase the facilities of the electric utilities serving the area.

There are two exceptions to the exclusive service right. After April 12, 1974, the exclusion by incorporation, consolidation, or annexation of any part of the assigned service area of an electric utility within the boundaries of a municipality does not impair the rights of the electric utility to continue and extend electric service at retail throughout any part of its assigned service area unless the municipality that owns and operates an electric utility elects to purchase the facilities and property of the electric utility. The other exception is for large customers. Customers located outside municipalities who require electric service with a connected load of 2,000 kilowatts or more are not obligated to take electric service from the electric utility having the assigned service area where the customer is located if the Public Utilities Commission determines after consideration of the following factors:

1. The electric service requirements of the load to be served.
2. The availability of an adequate power supply.
3. The development or improvement of the electric system of the utility seeking to provide the electric service, including the economic factors relating thereto.
4. The proximity of adequate facilities from which electric service of the type required may be delivered.
5. The preference of the customer.
6. Any and all pertinent factors affecting the ability of the utility to furnish adequate electric service to fulfill customers' requirements.

As in South Dakota, Minnesota electric utilities may extend electric lines for electric service to their own utility property and facilities.

Montana

The Montana Territorial Integrity Act is codified at Montana Code Annotated Section 69-5-101 et seq.; however, the provisions of the Act were substantially amended in the Electric Utility Industry Restructuring and Customer Act of 1997 to facilitate the implementation of that Act. Each electric service facilities provider has the right to provide electric service facilities to all premises being served by it or to which any of its facilities are attached on May 2, 1997. An electric utility is an entity other than an electric cooperative which provides electric service facilities to the public, and an electric cooperative is a rural electric cooperative or a foreign corporation admitted under the Montana cooperative statutes to do business in that state.

The electric facilities provider having a line nearest the premises provides electric service facilities to the premises initially requiring service after May 2, 1997, which creates a rebuttable presumption that the nearest line is the least-cost electric service facility to the new customer. A customer or another electric facilities provider may rebut the presumption, and another electric facilities provider may provide the electric service facilities if it can do so at less cost. An electric utility has the right to furnish electric service facilities to any premises if the estimated connected load for full operation at the premises will be 400 kilowatts or larger within two years from the date of initial service and if the electric utility can extend its facilities to the premises at less cost to the electric utility than the electric cooperative cost. The estimated connected load must be determined from the plans and specifications prepared for construction of the premises or, if an estimate is not available, must be determined by agreement of the electric facilities provider and the customer. The fact that the actual connected load after two years from the date of initial service is less than 400 kilowatts does not affect the right of the electric facilities provider initially providing electric service facilities to continue to provide electric service facilities to the premises.

Utilities can enter agreements that identify the geographical area to be exclusively served by each electric facilities provider that is a party to the agreement overriding the provisions of the Territorial Integrity Act. However, all agreements between electric facilities providers must be submitted to and approved by the Montana Public Service Commission. In approving agreements, the Montana Public Service Commission is required to consider the reasonable likelihood that the agreement will not cause a decrease in the reliability of electric service to the existing or future ratepayers of any electric facilities provider party to the agreement and the reasonable likelihood the agreement will eliminate existing or potentially uneconomic duplication of electric service facilities.

Testimony

The committee received testimony from the Public Service Commission that the 10 issues or factors that the commission considers in Territorial Integrity Act disputes are:

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?

Items 1, 9, and 10 were developed by the Public Service Commission while items 2, 3, 4, 5, 6, 7, and 8 are taken from Supreme Court decisions concerning the Territorial Integrity Act. The Public Service Commission reported that it received 483 Territorial Integrity Act applications between 1988 and the present. Of these, 458 applications were granted, 11 applications were denied, 12 applications were withdrawn, and two are pending. The Public Service Commission reported that rural electric cooperatives filed 33 objections of which 15 applications were granted, 11 applications were denied, and seven applications were withdrawn. There were four applications appealed during this time period and one complaint appealed.

The committee received testimony from representatives of the state's investor-owned utilities that the Territorial Integrity Act and subsequent court interpretations have provided the distribution cooperatives with an opportunity to infringe upon the cities that are served by investor-owned utilities. They testified that over the years this situation has cut off their opportunity to share in the growth of the communities they serve and thus it is not a question of whether a change in the law is necessary but what changes need to take place to ensure the future, long-term viability of all the electric service providers in the state. Representatives of the state's investor-owned utilities testified that rural electric cooperatives currently enjoy virtually all of the growth opportunities in the state.

The committee received testimony from representatives of Montana-Dakota Utilities Company concerning the municipalization of electric service in Watford City and Killdeer. The committee received testimony that the cities of Watford City and Killdeer may not renew Montana-Dakota Utilities Company's franchise to provide electric service in these cities, as they may form municipal utilities and invite McKenzie Rural Electric Cooperative to supply electricity to these cities. This testimony indicated that although representatives of the state's rural electric cooperatives testified to the contrary, this is an example of a rural electric cooperative moving into an area served by an investor-owned utility. This testimony indicated that the outcome of this dispute will eventually be of interest to the Legislative Assembly in that should Montana-Dakota Utilities Company lose its franchise, its electric and natural gas property will be removed from the property tax bases of these cities. With a reduced tax base, tax revenues to these cities will be reduced, resulting in less revenue to provide city services and school funding. This may result in these cities being classified as "property poor" and thus eligible for increased funding from the Legislative Assembly. In summary, representatives of Montana-Dakota Utilities Company testified that the activities of McKenzie Rural Electric violate the intent of the original Rural Electrification Act and represent an effort by a rural electric cooperative to move into cities served by an investor-owned utility.

Representatives of the state's rural electric cooperatives testified that the Territorial Integrity Act is working well, and avoids costly duplication of service. They testified that rural electric cooperatives should be able to participate in the state's growth areas as well as rural areas and that Congress never intended to limit cooperatives to serving only remote farmsteads and pasture wells, but federal and state law encouraged cooperatives to grow with their service areas. They testified that as some cities have expanded into the countryside where only the cooperatives were first willing to serve, the investor-owned utilities want to take away these growth areas at great cost to the consumers who built and own their own cooperative business. Representatives of the Association of Rural Electric Cooperatives argued that investor-owned utilities have had a fourfold increase in electric sales, a rate of growth comparable to the rural electric cooperatives, and the recent slowdown in the investor-owned utilities' growth rate is not because of state law, but because the state has not experienced the economic growth occurring in other states. They also said rural electric cooperatives have suffered more from this lack of growth than have the investor-owned utilities.

The committee received testimony from representatives of Fargo, Bismarck, and Minot concerning the franchising of electricity providers. The committee learned the city of Fargo has entered franchise agreements with two electricity providers--an investor-owned utility and a rural electric cooperative. These franchise agreements are nonexclusive, in that either provider can provide electric service anywhere within the city of Fargo. The committee learned the usual practice is for franchise agreements to be amended to allow the provider to provide service in areas annexed by the city, and if there is a conflict, it is referred to the Public Service Commission for resolution.

Concerning franchise agreements in Bismarck, the committee learned in 1973 Montana-Dakota Utilities Company and Capital Electric Cooperative entered an area services agreement effectively demarcating the area of service by each provider. When Capital Electric Cooperative was granted a franchise by the city of Bismarck to operate within the city, the area service agreement was incorporated into Capital Electric Cooperative's franchise agreement. The committee received testimony from representatives of the city of Bismarck that this system has worked relatively well with only one serious dispute, which was resolved by the Bismarck City Commission without the Public Service Commission becoming involved.

Concerning franchise agreements in Minot, the committee learned the franchise automatically follows into areas annexed by the city, and there has never been a disagreement between Xcel Energy, Inc., and Verendrye Electric Cooperative, the local rural electric cooperative, that has reached the city commission.

Conclusion

The committee makes no recommendation concerning its study of the Territorial Integrity Act.