ELECTRIC UTILITIES COMMITTEE

The Electric Utilities Committee was created by House Bill No. 1237 (1997) to study the impact of competition on the generation, transmission, and distribution of electric energy within this state. House Bill No. 1237 (1997) is codified as North Dakota Century Code (NDCC) Sections 54-35-18 through 54-35-18.2. Section 54-35-18 states that the Legislative Assembly finds that the economy of North Dakota depends on the availability of reliable, low-cost electric energy and that there is a national trend toward competition in the generation, transmission, and distribution of electric energy and that the Legislative Assembly acknowledges that this competition has both potential benefits and adverse impacts on the state's electric suppliers as well as on their shareholders and customers and citizens of this state.

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 electric suppliers. Electric suppliers include public utilities, rural electric cooperatives, municipal electric utilities, and power marketers.

Section 54-35-18.2 outlines the study areas that the committee is to address in carrying out its statutory responsibilities. This section provides that the committee is to study the state's electric industry competition and electric suppliers and financial issues; legal issues; social issues; issues related to system planning, operation, and reliability; and identify and review potential market structures. Also, although many states are studying the restructuring of their electric industries, this section requires the committee to review two areas unique to North Dakota that other states may not have addressed: (1) to what extent power produced by the Garrison Dam should be taxed by the state, and (2) the source and cost of power supply to the state's Indian reservations.

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 1998. The Council accepted the report for submission to the 56th Legislative Assembly.

ELECTRIC INDUSTRY RESTRUCTURING

Background

House Bill No. 1237 (1997) reflected the Legislative Assembly's concern that the electric industry is changing rapidly and that 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, generating efficiency may be encouraged through competition, and capital is allocated by the marketplace. However, risks and challenges of retail competition include maintaining reliability of supply, pricing outcomes in which some customers may benefit at the expense of others, and allocating stranded costs. The impetus for electric industry restructuring has also come from large industrial and commercial energy users that are opposed to subsidizing residential electricity users. For example, some industrial users are paying 150 percent of the actual cost of providing energy to those users, while residential customers are only paying 60 to 70 percent of the actual cost of providing energy to them.

The committee learned that competition is growing because of an awareness that generation, unlike transmission, does not have to be a monopoly business; a belief that market forces can produce lower electricity prices than can the overview of regulators; enactment of the Public Utilities Regulatory Policy Act which showed that nonutility generators can often compete successfully with utilities; and enactment of the Energy Policy Act of 1992, which allowed independent power producers to enter the power market without onerous regulation. Also, the committee learned competition is growing because of changes in technology and fuel prices that make power from many new generating plants cheaper than power from existing plants and adoption of the Federal Energy Regulatory Commission's open access rules in 1996, Federal Energy Regulatory Commission Order Nos. 888 and 889. The committee learned that these open access rules have created a vigorous competitive market for wholesale electricity, and this has stimulated demand for retail competition.

Traditional Rationale for Regulation

Under the current industry structure, electricity is provided to retail customers by utilities that have geographic monopolies on the provision of electric service within their service territories. Customers within a utility's service territory must purchase all of 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. These are 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 (FERC) governs the pricing of wholesale bulk power sales and transmission services. Although House Bill No. 1237 (1997) directs the committee 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, regulation of electric utilities engaged in the generation and distribution of light, heat, or power is performed by the state's Public Service Commission. 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 that 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.

As described above, traditionally, an electricity customer must purchase all of 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, which may be generated using a number of methods and fuel such as nuclear, coal, oil, natural gas, hydro, or wind. Transmission refers to the delivery of electricity over distances at high-voltage from a generation facility through a transmission network usually to one or more distribution substations, where the electricity is stepped down for distribution to residential, commercial, and industrial customers. For the retail customer, the costs for these functions are bundled into retail rates, along with the cost of distribution. Distribution involves the retail sale of electricity directly to consumers.

Other functions traditionally provided by vertically integrated utilities include customer service, billing, meter reading, demand-side management, research and development, and aggregation and ancillary services. Aggregation is the development and management of 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 of 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 traditionally 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 of 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. One critic has stated that rate of return regulation fails to penalize inefficient producers or reward efficient ones.

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; the incorporation of too many, or contradictory, societal or regulatory goals into the performance-based regulation plan; result in unreasonable returns to shareholders; or exacerbate 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 the Public Utility Regulatory Policy 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. However, states were allowed to determine the avoided costs and quantity of such power. Some states capped the price at the utility's avoided costs (the amount of money that an electric utility would need to spend for the next increment of electric generation that it instead buys from a cogenerator) 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.

Finally, the Federal Energy Regulatory Commission has taken a number of steps to encourage competition in the wholesale market. These actions include authorizing market-based rates, issuing Section 211 wheeling orders, ordering open access transmission tariffs, and issuing the open access transmission rule (FERC Order No. 888). Market-based rates are those set by willing buyers and sellers of power. This method may be used instead of the more traditional method of ratesetting by regulators pursuant to administrative hearings, with rates based on the cost of producing power. On April 24, 1996, 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 itself. In addition, the Federal Energy Regulatory Commission 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. Finally, the Federal Energy Regulatory Commission Order No. 888 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 California

In 1996 the California Legislature enacted a major restructuring bill that called for customer choice no later than January 1, 1998, created an independent system operator, established a power exchange, and funded stranded cost recovery through bonds. Provisions of the California legislation include:

- Customer choice commencing no later than January 1, 1998. The California Public Utilities Commission will establish a phasein schedule that is equitable for all customer classes which must be completed for all customers by January 1, 2002.
- An immediate rate reduction, through use of a bond financing mechanism, of not less than 10 percent for residential and small commercial customers. Additionally, rate savings for these customer classes are expected to be no less than 20 percent by April 1, 2002. Up to $10 billion in rate reduction bonds will be issued in order to achieve the immediate rate reduction and will spread recovery of a portion of competition transition charge for these customers over 10 years.
- A limited transition period, ending December 31, 2001, during which utilities have an opportunity to recover stranded investment through a nonbypassable competition transition charge levied on the usage of electric power. Recovery is limited to certain categories and types of costs and to only that portion that can be recovered under a rate freeze during the transition period.
- A "firewall" to shield residential and small commercial customers from paying for any competition transition charge exemptions granted to industrial users for economic development or retention purposes.
- An independent system operator and a power exchange subject to the jurisdiction of a five-member oversight board appointed by the Governor and the legislature. Publicly owned utilities and investor-owned utilities are required to give control of their transmission facilities to the independent system operator.
- A requirement that utilities continue funding energy conservation and low-income assistance programs through 2001 and that ratepayers pay for that portion recoverable under the rate freeze. Assistance programs must be funded at levels not less than those authorized for 1996. Funding for energy efficiency and conservation must at least equal $228 million per year through 2001; during the same period, $62.5 million must be provided for research, development, and demonstration projects to advance science or technology that would not otherwise be adequately provided for in a competitive market. The amount of $540 million is provided for renewable resource technologies in this time period.
- A requirement that all electric sellers, marketers, and aggregators register with the California Public Utilities Commission and provide consumers with adequate and reliable information regarding supplier options. Contract recision provisions and "antislamming" or "grid-napping" protections are also included in the legislation.

Maine

Legislation enacted by the Maine Legislature in 1997 established retail competition for the purchase and sale of electricity beginning March 1, 2000. The legislation permits electric utilities a reasonable opportunity to recover verifiable and unmitigable stranded costs and also establishes a standard-offer service for customers who do not seek or take power in the competitive marketplace. The law sets a 33 percent market-share cap for Central Maine Power Company and Bangor Hydro-Electric Company and preserves low-income assistance programs funded through transmission and distribution rates. It establishes a 30 percent renewal-resource portfolio requirement for competitive electricity providers and a program for renewable research development funded through voluntary contributions. Finally, it requires the Maine Public Utilities Commission to develop a consumer education program.

Montana

During the 1997 legislative session, the Montana Legislature enacted Senate Bill No. 390, the Montana Electric Utility Industry Restructuring and Consumer Choice Act. This Act established restructuring requirements for Montana's electric utility industry. Pilot programs began July 1, 1998, and a report on those programs is due by July 1, 2000. All utility customers must have a choice in their electricity supplier before July 1, 2002. All utilities must submit transition plans. Certain stranded costs laid out in transition plans will be reviewed and will be paid for by transition bonds. Beginning January 1, 1999, 2.4 percent of each utility's annual retail sales revenue in Montana for the calendar year ending December 31, 1995, is established as the annual funding level for universal system benefits programs. Unless otherwise modified, this funding level remains in effect until July 1, 2003. The recovery for these programs is authorized through a universal systems benefits charge assessed at each customer meter. One feature of the bill that is relevant to electric industry restructuring in North Dakota is how the bill deals with rural electric cooperatives. Section 20 of the bill provides that rural electric cooperatives have the choice of opting in or out of offering their customers choice. If a cooperative opts in, it must certify to the Montana Public Service Commission that it has adopted a transition plan consistent with the provisions of the Act, but essentially the same as the plans of investor-owned utilities. If a cooperative opts out, the cooperative is precluded from accessing the distribution system and, thus, customers of other utilities that have opened their system up without a preexisting contract. A cooperative must participate in the universal systems benefits program whether it opts in or out.

Oklahoma

Senate Bill No. 500, signed by the Governor of Oklahoma on April 25, 1997, created the Electric Restructuring Act of 1997 and stated electric utility industry restructuring goals for that state. The Act establishes customer choice by July 1, 2002. Before that date a series of studies will be conducted on various aspects of restructuring. These studies include:

- Formation of an independent system operator for Oklahoma or the region that must have begun by July 1, 1997, and reported by February 1, 1998.
- A study of technical issues, such as reliability, safety, and transmission, which must report findings by December 31, 1998.
- A study of financial issues such as rates, charges, and electric service provider financial obligations. This study must commence on January 1, 1999, and report findings by December 31, 1999.
- A study of consumer issues that must begin by July 1, 1999, and report findings by August 31, 2000.

In addition, the Oklahoma Tax Commission is conducting a study to assess the effect of restructuring on state, county, and local tax revenue and examining the feasibility of establishing a consumption-based tax to provide at least the existing level of revenue. This study must provide findings by December 31, 1998. The commission is prohibited from adopting any rules or issuing orders without prior authorization from the Oklahoma Legislature or the Joint Electric Utility Task Force.

New Hampshire

The relevant provisions of the New Hampshire restructuring legislation are:

- The New Hampshire Public Utilities Commission must have issued a final restructuring order by June 30, 1997. Utilities must have offered retail access by January 1, 1998. The New Hampshire Public Utilities Commission may delay this date by up to six months without legislative approval.
- Generation must at least be functionally separated from transmission and distribution functions. The Public Utilities Commission may require that distribution and electricity supply services be provided by separate utility affiliates. However, utilities may own small-scale generation facilities as a means of minimizing transmission and distribution costs. While divestiture is not required, utilities must mitigate their stranded costs, with the sale of surplus assets identified as one form of mitigation.
- In the implementation of full-fledged retail competition, utilities are allowed recovery of net, nonmitigable environmental costs and costs of legally mandated purchase power contracts. They are allowed to seek recovery of generation-related assets.
- The Act allows the Public Utilities Commission to establish a stranded cost recovery charge, with the burden of proof for recovery on the utility. It also allows the Public Utilities Commission to establish interim charges effective for two years from the date that utilities file plans to comply with the Act. The Act states that entry and exit fees are not preferred recovery mechanisms.

Pennsylvania

House Bill No. 1509, enacted by the Pennsylvania General Assembly in 1996, addressed electric industry restructuring in Pennsylvania. The major provisions are:

- By January 1, 1999, utilities must offer retail access to one-third of their peak load for each customer class; two-thirds by January 1, 2000; and all by January 1, 2001. Utilities must provide this opportunity on a first-come, first-served basis except as directed by the Pennsylvania Public Utilities Commission. The Pennsylvania Public Utilities Commission may delay implementation of the initial phase by up to one year.
- The Act requires unbundling of the generation, transmission, and distribution functions. Generation will be deregulated while transmission and distribution will continue to be regulated as natural monopolies. Divestiture is permitted but not required.
- Utilities are statutorily entitled to recover their nuclear decommissioning costs; contracts for power purchased from nonutility generators, and prudently incurred costs associated with buydowns and buyouts of these contracts; and regulatory assets. The Pennsylvania Public Utilities Commission may allow recovery of generation-related costs in addition to those listed above. Utilities must mitigate costs to the extent practicable through such measures as accelerated depreciation and minimize rates while maintaining safe and efficient operations.
- The Act establishes a competition transition charge applied to any customer using the transmission or distribution system. The competition transition charge may not shift costs between or within customer classes. Customers that install onsite generation and significantly reduce their purchases through transmission and distribution systems must pay a fully allocated competition transition charge.

- The Act establishes a cap on total rates for utility company customers for the shorter of 4.5 years or until the utility finishes collecting its stranded costs through transition charges and all customers can choose suppliers. The generation component of rates plus transition charges may not exceed current Public Utilities Commission-approved generation costs for the shorter of nine years or until the utility finishes collecting its stranded costs through transition charges and all customers can choose suppliers. Limited exceptions to these caps exist, for example, if they preclude a utility from earning its Public Utilities Commission-authorized rate of return on its investment.
- The Public Utilities Commission may issue a qualified rate order to allow issuance of transition bonds. Bonds may have a maturity of up to 10 years. Proceeds of the bonds must be used to reduce stranded costs and other transition costs. The competition transition charge must be reduced to the extent stranded costs have been refinanced. Savings and interest costs must be passed on directly to customers through rate reductions.
- The Act requires continuation of gross receipts and other state utility taxes with a formula to maintain revenue neutrality through 2003. The gross receipts tax applies to nonutility electric suppliers.

Rhode Island

The 1996 Rhode Island electric restructuring initiative, codified as Rhode Island General Laws § 39-1-27 et seq., provides:

- As of July 1, 1997, utilities must offer retail access to all new commercial and industrial customers, all existing manufacturing customers with average annual demand of 1,500 kilowatts or more, and all accounts of the state government, subject to an overall cap of 10 percent of the utility's total sales.
- As of January 1, 1998, utilities must offer retail access to all existing manufacturing customers with average annual demand of 200 kilowatts or more and all accounts of municipal governments. Utilities are not required to provide retail access to customers accounting for more than 20 percent of their total sales under this and the preceding provision.
- As of July 1, 1998, utilities must offer retail access to all of their remaining customers. This deadline is moved up if retail access is available to 40 percent or more of total sales in New England. The Rhode Island Public Utilities Commission may delay this deadline by up to six months to permit extension of retail access on reasonable terms.
- The Act requires unbundling of generation, transmission, and distribution functions. Generation will be deregulated, while transmission and distribution will continue to be regulated by the federal Energy Regulatory Commission and Rhode Island Public Utilities Commission, respectively. Any utility recovering a stranded cost through the transition charge must determine the market value of its fossil fuel and hydrogenerating assets by the sale or spinoff of these facilities. The market value is then deducted from the utility's stranded costs. Utilities must also attempt to sell their portion of their purchase power contracts that exceed market rates to reduce their stranded costs.
- Stranded costs include nuclear decommissioning costs and nuclear operation and maintenance costs that would continue if the plant were shut down; above-market costs of purchase power contracts and the reasonable costs of buying out or buying down these contracts; regulatory assets; and the net unrecovered capital costs of all of the generating plants owned by the utility or its wholesale power distributor as of December 31, 1995, whether or not plants are operating.
- The Act establishes a transition charge applied to any customer using the transmission or distribution system. A nonutility electric supplier may pay part or all of its customer's transition charge. The charge is set at 2.8 cents per kilowatt hour for the period between July 1, 1997, and December 31, 2000. The charge is subject to adjustment to account for the disposition, pursuant to the Act, of nonnuclear generating assets by wholesale power suppliers. From January 1, 2001, the Public Utilities Commission sets the charge. After January 1, 2010, there is no allowance for costs associated with regulatory assets and unamortized capital investments in generating plants.
- Rate increases generally must hold to the rate of inflation from January 1, 1997, through December 31, 1998. These increases do not apply to low-income customers. Utilities must file performance-based rate plans with the Public Utilities Commission.
- The Act establishes a commission that was required to submit a plan to the General Assembly by January 1, 1997, on assessing and taxing utilities and nonregulated power producers.

TESTIMONY AND COMMITTEE ACTIVITIES

The Regulated Electric Industry in North Dakota

The regulated electric industry in North Dakota consists of Montana Dakota Utilities Company, Northern States Power Company, and Otter Tail Power Company. Montana Dakota Utilities Company provides electric service in Bismarck, Dickinson, Williston, and Jamestown, along with numerous smaller cities in western North Dakota. Montana Dakota Utilities Company has 68,607 electric customers. Northern States Power Company provides electric service in Minot, Fargo, and Grand Forks and has 80,684 electric customers. Otter Tail Power Company provides electric service in Jamestown, Devils Lake, Wahpeton, and many other smaller cities throughout central and eastern North Dakota. Otter Tail Power Company has 56,276 electric customers. The Public Service Commission does not regulate rural electric cooperatives or municipal utilities.

Federal Restructuring Initiatives

The committee monitored electric industry restructuring activities at the federal level throughout the interim. Nine bills relating to electric industry restructuring have been introduced in the 105th Congress. The committee learned that key issues that must be addressed in any federal legislation are linking repeal of the Public Utility Holding Company Act, the Public Utility Regulatory Policy Act, and retail choice in federal legislation; the conflict between state's rights in promoting interstate commerce; the issue of public power; the issue of stranded costs; the issue of how social benefits such as low-income programs, conservation programs, and renewable requirements are integrated into restructuring issues; competition issues such as mergers and antitrust; and reliability concerns.

H.R. 388 - This bill, known as the Ratepayer Protection Act, would repeal the qualifying facility mandatory purchase provisions of the Public Utility Regulatory Policies Act of 1978, would be effective as of the date of the bill's introduction, and would not impact existing contracts.

H.R. 655 - This bill, known as the Electric Consumer's Power to Choose Act of 1997, would provide for retail choice no later than December 15, 2000, address the issue of stranded costs, would suspend the Public Utility Holding Company Act of 1935 and the Public Utility Regulatory Policies Act of 1978 when customer choice becomes effective but would not abrogate existing mandatory purchase contracts. Concerning state jurisdiction, states would maintain some authority over every retail transaction so that they may continue to fund public service programs and provide for the recovery of retail stranded costs.

H.R. 1230 - This bill, known as the Consumers Electric Power Act of 1997, would guarantee every customer the right to choose their electricity service provider by January 1, 1999; ensure that electric service providers are allowed access to compete on a level playing field; preserve and strengthen state authority with regard to universal service for consumers, universal access for providers, conservation programs, and future economic development programs; outline the performance objectives of competitive transmission and distribution systems; prospectively repeal the Public Utility Holding Company Act of 1935 and the Public Utility Regulatory Policies Act of 1978 after competition is affirmatively achieved; and reject stranded cost recovery the bill would ban exit fees, subsidies, or other penalties on exercising the right of choice.

H.R. 1359 - This bill would protect the environment and low-income families as a result of electric utility industry deregulation. The bill would amend the Public Utility Regulatory Policies Act of 1978 to create a joint federal-state board to administer, with Department of Energy oversight, a national program to provide matching grants to state and local programs promoting energy conservation, renewable energy resources such as wind and solar power, and universal electricity service for low-income, rural, and other consumers for whom basic electricity service might be compromised by deregulation. The national program would be funded by a transmission access charge paid by all electricity suppliers.

H.R. 1960 - This bill, known as the Electric Power Competition and Consumer Choice Act of 1997, would require each state to initiate a retail competition rulemaking proceeding. The bill would leave decisions on stranded cost recovery to the state with the restriction that such recovery be limited to legitimate, verifiable, and nonmitigable stranded costs for which there is a reasonable expectation of recovery. The bill would repeal the Public Utility Holding Company Act of 1935 and the mandatory power purchase provisions of the Public Utility Regulatory Policies Act of 1978 for utilities in those states that elect full retail competition and protects certain public benefit programs, such as those relating to renewables, energy efficiency, worker retraining, and low-income consumers. Concerning retail supply reciprocity, the bill would prevent utilities from providing electricity services in states that open up to competition unless such services can legally be offered on a competitive basis in the utility's home markets. The bill would give the Federal Energy Regulatory Commission and the states enhanced authority to oversee utility mergers and acquisitions, curb excessive utility market power and guard against anticompetitive practices, to review utility interaffiliate transactions to protect consumers from cross-subsidization or self-dealing, and to obtain full access to electric utility books and records. The bill would impose Federal Energy Regulatory Commission Order Nos. 888 and 889 as well as any future open-access rules on nonjurisdiction transmission owners and the Federal Power Marketing Administration. The bill would direct the Federal Energy Regulatory Commission to establish regional transmission markets to assure functionally efficient and nondiscriminatory electricity transmission and prevent pancaking of transmission rates and would direct the President or the President's designee to issue rules to prevent utilities from gaining any competitive advantage from ownership or control of dirtier power plants that are not subject to the Environmental Protection Agency's new generation source pollution standards. The bill would give the Federal Trade Commission authority to issue rules to ensure electricity consumers receive fair and full disclosures regarding the prices, generation sources, emissions, and other information regarding the electricity they purchase and establish an electric reliability council to serve as an industry self-regulatory organization, overseen by the Federal Energy Regulatory Commission, to assure reliability. Finally, the bill would create a federal-state board to review universal service requirements in a restructured electricity industry and promote increased reliance on environmentally-sustainable, renewable energy technologies by creating a renewable energy credit trading system managed by the Department of Energy that would require all generators of electricity to submit credits increasing from 3 percent to 10 percent of total sales between the date of enactment and 2010.

S. 237 - This bill, known as the Electric Consumers Protection Act of 1997, would provide for mandatory retail customer choice beginning on December 15, 2003. The bill would allow for the recovery of stranded investment and facilities that become uneconomic as a result of the transition to retail competition and provides that a utility seeking stranded cost recovery must ask the jurisdictional state regulatory authority to calculate the amount of stranded costs. If the state authority agrees to do so, it may do so in one of two ways. The state authority may determine the level of the utility's legitimate, prudently incurred and verifiable investments in generating assets and related regulatory assets that cannot be mitigated or require the utility to divest itself of all its generating facilities and then subtract the revenue received from the book value of the assets sold. If the state authority does not calculate the stranded costs, the Federal Energy Regulatory Commission must require the utility to sell its generating facilities in order to calculate stranded costs. Concerning universal service, state regulators may impose an obligation on retail suppliers to sell power to or purchase power on behalf of customers that do not have sufficient access to competing retail suppliers. Concerning renewable energy requirements, for each retail supplier, five percent of generation beginning in 2003, nine percent beginning in 2008, and 12 percent beginning in 2013 must be obtained from renewable sources. These requirements expire in 2019, and utilities would be allowed to include hydroelectric power among the required forms of renewable energy. Concerning regional transmission systems, the Federal Energy Regulatory Commission would be required to establish transmission regions and designate an independent system operator to operate all transmission facilities in each region beginning December 15, 2003. States in each region would be allowed to form a regional transmission oversight board to oversee the independent system operator, regional boards would have the same authority the Federal Energy Regulatory Commission currently exercises over transmission pursuant to the Federal Power Act, and where such boards are not formed, the Federal Energy Regulatory Commission would retain its existing authority. Federal Energy Regulatory Commission authority over utility mergers would be extended to electric utility mergers with natural gas companies. The commission would be required to take into account the impact of a merger on competitive wholesale and retail electric generation markets. Utilities owning nuclear power plants prior to the date of enactment would be entitled to recover costs to fund decommissioning of the plants from their customers. Beginning December 15, 2003, the Tennessee Valley Authority would be allowed to sell retail and wholesale electric energy outside of its service territory and its retail and wholesale customers could buy energy from other sellers. The bill would repeal the Public Utility Holding Company Act of 1935 one year from enactment, while retaining certain consumer safeguards. The bill would repeal the mandatory purchase obligation provisions of the Public Utility Regulatory Policies Act for facilities beginning commercial operation after December 15, 2003, unless the power purchase contract relating to the facility was in effect on that date and requires the Environmental Protection Agency to submit a study to Congress by January 1, 2000, which examines the implications of wholesale and retail electric competition on the emission of pollutants and recommends any changes in law needed to protect public health and the environment.

S. 621 - This bill, known as the Public Utility Holding Company Act of 1997, would repeal the Public Utility Holding Company Act of 1935; allow holding companies to diversify into utility or nonutility business ventures and permit ownership of utility companies in more than one state; provide state and federal regulators with the necessary authority to examine books and records and conduct audits of public utility holding companies and their subsidiaries; and transfer ratemaking functions from the Securities and Exchange Commission to the Federal Energy Regulatory Commission and the states, thus eliminating the regulatory gap created by the United States Supreme Court's 1992 *Ohio Power* decision.

S. 687 - This bill, known as the Electric System Public Benefit Protection Act, would direct the Secretary of Energy to establish a national electric system public benefits board to administer a public benefits fund to enable and encourage state programs for renewable energy technologies, energy efficiency, low-income assistance, and universal access. The fund would be supported by a broad-based, competitively neutral, systems benefits charge to be imposed by the Federal Energy Regulatory Commission as a wires charge on all interconnected generation for sale on the electricity market, and the bill provides that revenues from the fund would be used to match funds raised by the states. The bill would establish a renewables portfolio standard for all nonhydroelectric electricity generation companies of 2.5 percent in 2000 and 20 percent in 2020 and each year thereafter, and provides that the Federal Energy Regulatory Commission would administer a renewable energy trading program. The bill would repeal the mandatory purchase obligation provisions of the Public Utility Regulatory Policies Act of 1978 effective January 1, 2000. The bill would direct the Environmental Protection Agency to adopt a final regulation establishing a schedule of limits on the amounts of each pollutant that may be emitted by nonnuclear electric generation facilities with a capacity of fifteen megawatts or more beginning in calendar year 2000. The schedule of limits prescribed by the legislation is intended to significantly reduce emissions of sulfur dioxide and carbon nitrogen oxide.

S. 722 - This bill, known as the Electric Utility Restructuring Empowerment and Competitiveness Act, would reject federal retail competition mandates by reserving to the states all authority over retail electric matters. The bill prospectively exempts the sale of electricity for resale from Federal Energy Regulatory Commission rate regulation and provides that the Federal Energy Regulatory Commission would continue to regulate transmission in interstate commerce while state public utility commissions would continue to regulate retail distribution services and sales. The bill would expand Federal Energy Regulatory Commission authority to require wholesale open access by nonpublic utilities, including federal power marketing agencies, the Tennessee Valley Authority, municipalities, and cooperatives. The bill would repeal the mandatory purchase obligation provisions of the Public Utility Regulatory Policies Act of 1978. The bill incorporates the text of S. 621, the bill repealing the Public Utility Holding Company Act of 1935 and transferring certain regulatory functions from the Securities and Exchange Commission to the Federal Energy Regulatory Commission and the various state public utility regulatory commissions. Finally, the bill would direct the inspector general of the Treasury Department to report to Congress on whether and how tax code incentives received by all utilities should be reviewed in order to foster a competitive retail electricity market in the future.

Electric Utility Taxation in Other States

In addition to monitoring state electric utility restructuring initiatives and reviewing federal electric industry restructuring activities, the committee examined electric utility taxation activities in other states. The committee received testimony that experience has shown that those states that enacted electric utility restructuring initiatives without first addressing the tax implications have encountered problems. The committee received testimony that any tax system should be competitively neutral, that all providers of electricity in the state should be taxed on an equal basis, and that the tax system must avoid nexus problems that may arise when taxing new market entrants and out-of-state providers of electricity. The committee received testimony that the tax system should be revenue neutral to the state when it is first established and provide a stable revenue source to the state in the future. The committee also received testimony that the tax system should be relatively easy to understand and to administer.

The committee received testimony from a representative of the Environment, Energy, and Transportation Program of the National Conference of State Legislatures that tax matters identified in other states include the nexus issue, identification of programs depending upon utility tax revenues, revenue neutrality, and the impact on taxpayers. Nexus means whether an electricity provider has a significant enough relationship with a state to be subject to taxation by that state. The committee learned that Montana, Nevada, Oklahoma, and Virginia are studying taxation of electric utilities while Maine and California enacted restructuring legislation without addressing the tax issue. Pennsylvania, Rhode Island, New Hampshire, Illinois, Connecticut, Massachusetts, and Arizona have addressed taxes while New Jersey, Vermont, Missouri, and Iowa addressed the issue before restructuring their state's electric utility industry.

While New Jersey has not yet restructured its electric industry, it has addressed electric utility taxes by eliminating the gross receipts and franchise taxes on electric utilities and replacing them with a corporate business tax. Also, sales and use taxes are applied to the retail sale of electricity and natural gas. Local governments are guaranteed an annual state distribution of at least $730 million to replace any lost revenues and an instate presence is required of all electricity providers to satisfy the nexus requirement.

Although Iowa has not passed restructuring legislation, it has addressed tax issues of a restructured system. The Iowa tax system is intended to raise the same amount of revenue from the same types of utilities, distribute the same amount of revenue to each local taxing jurisdiction, and remove any competitive tax disadvantage for Iowa-based utilities as compared to out-of-state utilities and power marketers. The Iowa tax legislation imposes an electricity generation tax of .0006 cents per kilowatt hour; an electricity transmission tax based on pole miles; an electricity delivery tax based on kilowatt hours delivered to consumers within each Iowa service area; a natural gas delivery tax based on 100,000 British thermal units of natural gas delivered to consumers within each service area; and a statewide utility property tax.

In 1997 Illinois passed restructuring legislation and addressed the tax issue as part of the restructuring package. Under Illinois House Bill No. 362 an electricity use tax is imposed on the privilege of using electricity purchased for use and consumption, but not for resale.

Rhode Island passed restructuring legislation in 1996. Although gross receipts taxes on power plants were already revenue neutral, the Rhode Island legislation subjected electric generation from existing plants to the state inventory tax, while exempting new power plants.

New Hampshire has repealed its franchise tax on electric utilities and replaced it with a tax on electricity consumption and also imposed a new real estate tax.

Pennsylvania enacted restructuring legislation in 1996. Pennsylvania House Bill No. 1509 extended the gross receipts tax to nonutility providers and municipal companies and rural cooperatives for sales outside established service territories. The Pennsylvania legislation contains a revenue neutral reconciliation formula and addresses the nexus issue by requiring all electricity providers to be licensed by the state. Finally, there is no shifting of tax burdens among customer classes.

Connecticut enacted restructuring legislation in April 1998. Concerning taxation, the goal of the Connecticut legislation was revenue neutrality and it shifted the gross earnings tax from generation and increased the gross earnings tax on transmission and distribution. To address the nexus issue, it defined doing business in the state as including engaging in or conducting business in the state. Also, generation, transmission, and distribution of electricity are included as tangible personal property for the purposes of the state sales tax and the legislation provided for partial reimbursement for lost property tax and loss of value resulting from restructuring.

Massachusetts enacted restructuring legislation in 1997. Concerning taxation, utilities are responsible for making transition payments to any municipality in which a generation facility is located. The production of electricity is not considered manufacturing and is therefore subject to taxation.

Arizona legislation requires an electricity supplier to obtain a certificate from the Arizona Corporation Commission which subjects the supplier to transaction privilege taxes, affiliated excise taxes, and a model city tax code. Counties currently having an excise tax can levy a use tax on electricity customers using or consuming electricity purchased from an electricity supplier. Finally, the Arizona legislation expands the utilities classification of the transaction privilege tax.

Vermont, in its electricity restructuring legislation, froze property tax values at their April 1, 1997, level until January 1, 2000. The legislation is designed to keep property tax values even in a time of declining hydro plant values.

Electric Industry Taxation Task Force

The Electric Utilities Committee authorized the formation of an Electric Industry Taxation Task Force to determine areas of common agreement and consider possible changes to current electric utility taxation. The task force included representatives of the state's investor-owned utilities, rural electric cooperatives, municipal electric utilities, and power marketers. The task force met three times, and a data subcommittee formed to compile industry data met three times. The task force reported on its activities and presented statistical information it compiled at the final meeting of the Electric Utilities Committee. The task force reported information concerning generation, transmission, customer or retail sales, and taxes paid.

The task force presented information concerning electric generation plants by type of facility, capacity, and ownership interest. North Dakota has 3,863 megawatts of baseload coal fired capacity. The baseload coal-fired capacity consists of Units 1 and 2 of the Antelope Valley Station, which is owned by Basin Electric Power Cooperative; Units 1 and 2 of the Coal Creek Station, which is 56 percent owned by Cooperative Power Association and 44 percent owned by United Power Association; Coyote Station, which is 25 percent owned by Montana Dakota Utilities Company, 35 percent owned by Otter Tail Power Company, 30 percent owned by the Northern Municipal Power Agency, and 10 percent owned by Northwestern Public Service; Units 1 and 2 of the Leland Olds Station, which is owned by Basin Electric Power Cooperative; Milton R. Young Station Unit 1, which is owned by Minnkota Power Cooperative; Milton R. Young Station Unit 2, which is owned by Square Butte Electric Cooperative; R. M. Heskett Station, which is owned by Montana Dakota Utilities Company; and the UPA Stanton Plant, which is owned by United Power Association.

The five units at Garrison Dam provide 494 megawatts of baseload hydropower. The Garrison Dam units are operated by the Western Area Power Administration.

North Dakota has a capacity of 77 megawatts of standby peaking power. Thus, the total capacity of power plants in North Dakota is 4,434 megawatts.

For 1995-97 Antelope Valley Station generated an annual average of $2,726,350 in coal conversion taxes; Coal Creek Station generated an annual average of $3,311,207; Coyote Station generated an annual average of $1,192,531; Leland Olds Station generated an annual average of $1,785,450; Milton R. Young Station generated an annual average of $2,088,987; and the Stanton UPA Station generated an annual average of $487,991. Based upon these figures, North Dakota power plants generate an average of $11,591,528 in coal conversion taxes per year. The conversion tax is in lieu of property taxes on the plants, but not on the land which remains subject to property taxes. This 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 R. M. Heskett coal-fired generation facility, with rated capacity of 86 megawatts, is not subject to the coal conversion tax, but is centrally assessed as part of the public utility property taxes paid by Montana Dakota Utilities Company. The estimated average yearly tax attributable to the R. M. Heskett plant for 1995-97 is $404,964. The standby or peaking facilities owned by the investor-owned utilities are also subject to the public utility property tax, which totals approximately $110,000 per year. Neither the federal government nor the municipal utilities pay property taxes on their generation facilities.

North Dakota has over 12,000 miles of transmission lines, including over 10,000 miles that are owned by rural electric cooperatives and investor-owned utilities, and 2,000 miles owned by the Western Area Power Administration. The state's generation and transmission cooperatives own 4,189.2 miles of transmission lines, the state's distribution cooperatives own 1,137.6 miles of transmission lines, the state's investor-owned utilities own 4,833.6 miles of transmission lines, and the Western Area Power Administration operates 2,056.2 miles of transmission lines. The state's generation and transmission cooperatives pay an average of $410,395 in transmission line taxes per year. This tax is only assessed on transmission lines of 230 kilovolts or more, owned by rural electric utilities. The tax is assessed at the rate of $225 per mile. For investor-owned utilities, transmission lines are included as part of their public utility property taxes and as a federal agency, Western Area Power Administration transmission lines are not subject to North Dakota taxes.

The task force also reported data on retail electric sales for each North Dakota utility by residential or farm or other classification. The other classification includes small and large commercial and industrial customers, irrigation, and sales to public authorities.

For 1995 through 1997 the state's cooperatives averaged 96,568 residential or farm customers and 1,587,695 megawatts of electricity sold. There were 15,549 customers classified as other with 1,768,818 megawatts of electricity sold. The total average number of customers for this period for the state's cooperatives was 112,117, and they used a yearly average of 3,356,514 megawatts of electricity.

The state's investor-owned utilities served an average of 173,986 residential or farm customers during this period who used a yearly average of 1,735,523 megawatts of electricity. The investor-owned utilities served 32,022 customers classified as other who used a yearly average of 2,677,210 megawatts of electricity during this period. The total number of customers for the state's investor-owned utilities averaged 206,008, and the total megawatt sales of electricity averaged 4,412,733.

The state's municipal electric systems reported 9,035 residential or farm customers who used 129,206 megawatts of electricity in 1997. The municipal electric utility systems reported 1,064 customers classified as other who used 122,444 megawatts of electricity in 1997. Thus, the total figures for 1997 for the state's municipal electric utilities was 10,899 customers who used 251,650 megawatts of electricity.

The task force also compiled and reported on taxes that relate primarily to the distribution of electricity. North Dakota's distribution and generation and transmission cooperatives paid $5,720,961 in gross receipts taxes in 1995, $6,084,681 in 1996, and $5,878,495 in 1997, or an annual average of $5,894,712. The gross receipts tax is in lieu of a personal property tax and is a two percent tax on all cooperative revenue excluding only the sale of capital assets and revenue attributable to electric generation plants subject to the coal conversion tax.

Two distribution cooperatives are subject to an electric utility city privilege tax. The electric utility city privilege taxes paid by these distribution cooperatives totaled $3,751 in 1995, $4,093 in 1996, and $4,597 in 1997, or an annual average of $4,147 per year. The city privilege tax is authorized by state law to be imposed by cities on cooperatives in addition to the gross receipts tax. It is an ad valorem tax on cooperative electric distribution facilities within a municipality. The amount of the tax must be reduced by the amount of gross receipts tax that is allocated to the city.

The state's investor-owned utilities paid $5,621,666 in public utility property taxes in 1995, $5,825,978 in 1996, and $6,104,646 in 1997, or an annual average of $5,850,765. These figures exclude the portion attributable to real estate. The task force also reported on electric utility real estate taxes paid by company for 1995, 1996, and 1997. The state received an average of $472,239 per year for those taxes during this period.

Concerning income taxes paid by the state's investor-owned utilities, the state's investor-owned utilities paid $2,692,517 in 1995; $2,697,279 in 1996; and $2,158,826 in 1997; or a yearly average of $2,516,207 during this period. Although the state's investor-owned utilities are subject to state income tax, the state's rural electric cooperatives, as nonprofit entities, are generally not subject to income taxation. However, several of the generation and transmission cooperatives are subject to income taxation.

Municipal electric utilities make payments in lieu of taxes to their city general funds from the revenues of their utility operations. The state has 12 municipal electric utilities: Cavalier, Grafton, Hillsboro, Hope, Lakota, Maddock, Northwood, Park River, Riverdale, Sharon, Stanton, and Valley City. The municipal electric utilities paid $1,510,700 in lieu of taxes in 1995, $1,564,051 in 1996, and $1,667,471 in 1997, or an annual average of $1,580,741.

In summary, the task force reported that the state receives an average of $11,591,528 in coal conversion taxes, $5,850,764 in public utility property taxes, $472,239 in real estate taxes, $5,894,712 in gross receipts taxes, $4,147,000 in city privilege taxes, $2,516,207 in income taxes, and $1,580,741 in payments in lieu of taxes or an annual average of $28,320,733 per year.

Representatives of the state's rural electric cooperatives proposed a distribution tax per megawatt of $1.43 to be levied in lieu of current property-based taxes. Under the proposal, a tax of $1.43 per megawatt or $.00143 per kilowatt hour would be levied on retail electricity distributed in North Dakota, whether by an investor-owned utility, a rural electric cooperative, or a municipal electric utility. The tax would be paid by the distribution utility, and in the event of retail wheeling, would be a nonbypassable tariff. The distribution tax would be in lieu of current distribution taxes paid by the investor-owned utilities and the rural electric cooperatives. For the rural electric cooperatives, the proposal includes the elimination of the two percent gross receipts tax and the city privilege tax. Current taxes on high-voltage transmission lines and the land taxes would remain the same. For the state's investor-owned utilities, the proposal would include the elimination of the public utility property tax to be replaced by the distribution tax. In addition, investor-owned utilities would be assessed the high-voltage transmission line tax and the land tax on the same basis as the rural electric cooperatives, and would pay a property tax or other tax on generating facilities. For the state's municipal electric utilities, the proposal would be a new tax, but the proponents anticipated that the revenue generated by the tax would be returned to the county or municipality from which the taxes were assessed. The $1.43 per megawatt was determined by reviewing three years of data on megawatt sales and taxes paid by the state's investor-owned utilities and rural electric cooperatives. The investor-owned utility property tax figures were adjusted to reflect the addition of a high-voltage transmission line tax and to discount taxes on land and generation facilities. The proponents testified that the adjusted investor-owned utility taxes are directly comparable to the rural electric cooperatives two percent gross receipts tax and the city privilege tax which are both in lieu of a personal property tax. The investor-owned utility and rural electric cooperative distribution taxes were combined and divided by the total investor-owned utility and rural electric cooperative retail electric sales to arrive at the rate that would replace the taxes eliminated. This rate is $1.427 or $1.43 per megawatt. Proponents of the $1.43 per megawatt tax in lieu of the current distribution taxes reported that the tax would result in an increase of $652,859 to the distribution cooperatives, a decrease of $1,751,903 to the generation and transmission cooperatives, and an increase of $1,125,928 to the state's investor-owned utilities for a net increase of $26,884 over current distribution taxes. The tax would result in a decrease of $1,407,065 for the state's municipal electric utilities.

Representatives of the state's investor-owned utilities proposed a flat rate consumption tax on all electric sales on a per kilowatt hour or megawatt basis. Under the proposal, all existing taxes would be designated in lieu of the new consumption tax and a sunset clause would be imposed to ensure that the Legislative Assembly addresses the issue at a future date. The net effect would be that no current taxpayer would pay more taxes than are currently being paid; however, out-of-state power marketers, because they do not pay any of the current state taxes, would be captured by the consumption tax. This concept is similar to legislation enacted by the Legislative Assembly in 1997 which was designed to address out-of-state coal shipments to the state's generating plants.

Territorial Integrity Act Background

In conducting its study of the impact of competition on the generation, transmission, and distribution of electric energy within this state, the committee reviewed the history and operation of the Territorial Integrity Act. This law 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.
- **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 his 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" shall mean a privately owned supplier of electricity offering to supply or supplying electricity to the general public.
2. "Person" shall include an individual, an electric public utility, a corporation, a limited liability company, an association, or a rural electric cooperative.
3. "Rural electric cooperative" shall include 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.

It should be noted that as enacted, the Territorial Integrity Act included a section that provided that 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." However, in *Montana-Dakota Utilities Co. v. Johanneson*, 153 N.W.2d 414 (N.D. 1967), this section was declared 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."

Under the Act, a public utility may not begin the construction or extension of a public utility plant or system until a certificate of public convenience and necessity is obtained for the construction or extension. A public utility also may not extend transmission or distribution lines beyond the corporate limits of a municipality or serve any customer outside a municipality, unless an order and a certificate of public convenience and necessity is first gained. In addition, the Supreme Court established a requirement in *Capital Electric* 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.

While the Act did not require the public utility companies to discontinue service to customers who were being served outside municipalities before the effective date of the Act, they were required to file maps within 90 days showing all such customers, or it was conclusively presumed that the customers were not being served. In this event, the customers could not be served unless authorized by the commission in accordance with those provisions of the Act relating to extensions of service.

Public utilities were allowed to make extensions of service in municipalities in which they had lawfully commenced operations without obtaining a certificate if the extension would not interfere with services already provided by a cooperative or another public utility, or result in an unreasonable duplication of services.

Certain limitations were placed on the issuance of orders and certificates of public convenience and necessity by the Public Service Commission, in that such orders and certificates were not to be issued to any private utility to allow an extension of distribution lines outside a municipality or allow the service of a new customer outside the municipality, unless the nearest cooperative had consented to the service in writing, or unless it was shown upon hearing that the cooperative could not supply the service. Certificates were not necessary for the extension of facilities if a "consent" agreement was entered into between the cooperative and the public utility as to service areas, and the agreement was approved by the Public Service Commission.

Thus, the 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. As noted above, this objection to the effect of the Territorial Integrity Act culminated in *Montana-Dakota Utilities Co. v. Johanneson*, which squarely attacked its constitutionality. In *Johanneson*, the public utility companies took the position that the law was an unconstitutional classification for several reasons. They contended that 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. Further, 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. Finally, they asserted that cooperatives had a right to complain against public utilities' actions, but the utilities had no such right as against actions of the cooperatives. Thus, they maintained that 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 was held that the Act did amount to a classification in that public utilities and cooperatives were treated dissimilarly, but that 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 court reasoned, 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 which conditioned the issuance of certificates of public convenience and necessity on the written consent of the nearest cooperative, or upon a finding that 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 into 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 that 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, found that the issuing of conditional certificates without hearing was proper, provided that the controversy was fully submitted to the commission by an interested party in such a manner so that a decision could be made, and that 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 upheld.

Although the primary purpose of the Act was to keep to a minimum wasteful duplication of capital-intensive utility services and conflicts between suppliers of electricity, a continuous series of disputes, as discussed in *Tri-County Electric Cooperative v. Elkin*, 224 N.W.2d 785 (N.D. 1974), has arisen between rural electric cooperatives and stockholder-owned utilities. The court noted that typically, these suits arise from disputes as to which supplier of electricity is entitled to serve a customer in a rural area near a municipality where the investor-owned utility holds a franchise. The court further noted that when Section 3 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.

The court has established a requirement that a new customer's request for service by an electric public utility is necessary to invoke the Public Service Commission's jurisdiction to consider the public utility's application for a certificate of public convenience and necessity to extend service to an area outside the corporate limits of a municipality. *Capital Electric Cooperative Inc. v. Public Service Commission*, 534 N.W.2d 587, 592 (N.D. 1995)

Testimony

Representatives of Montana Dakota Utilities Company testified that the Territorial Integrity Act is outdated and patently 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. Also, they testified that if rural electric cooperatives wish to pursue loads in urban areas, in direct competition with public utilities, then it follows that the rural electric cooperatives engaging in such activity should no longer qualify for subsidies such as 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 oversight as public utilities.

The committee received testimony that if a rural electric cooperative wishes to continue to enjoy its preferential treatment and operate its system within the spirit and intent of the Rural Electrification Act, it should be prohibited, by statute, from serving newly annexed areas of a city and as such, the cooperative would be ineligible to apply for a city franchise to serve new loads in the annexed area, but the city could give the rural electric cooperative a limited franchise to continue to serve customers it is serving, upon the effective date of annexation. The committee received testimony that rural electric cooperatives should not have the benefits of low-cost federal financing, tax benefits, and lack of state regulation, while competing with public utilities for the same customers. Opponents of the Territorial Integrity Act testified that cooperatives be required to exercise a choice, to serve in a urban area, with the loss of preferential treatment at least for the increment of loads served in the urban area, or exclusively operate, except on an incidental basis, in rural areas, as originally contemplated by the drafters of the Rural Electrification Act.

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 that the rural electric cooperatives cannot penetrate and that the Act avoids the costly duplication of utility infrastructure. Representatives of the rural electric cooperatives responded that the Territorial Integrity Act provides for consumer choice, but this private choice must also be in the public interest. They noted that 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 made a huge investment to serve rural North Dakota. Representatives of the rural electric cooperatives responded to the charge that investor-owned utilities are competitively disadvantaged by the Territorial Integrity Act by testifying that since enactment of the territorial integrity law, investor-owned utilities have continued to grow in customers and revenue and that investor-owned utilities 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; that the growth of the local rural electric cooperative around Fargo is overstated; and that rural electric cooperatives are not precluded from competition because they have obtained Rural Utilities Service formally Rural Electrification Administration loans.

Year 2000 Problem

The committee also monitored the year 2000 (Y2K) computer problem as it affects the state's electric utility industry. The committee received testimony from the Public Service Commission that the commission is taking appropriate steps to address the Y2K problem. The commission is monitoring the efforts of the Midcontinent Area Power Pool Y2K Task Force. The task force was formed in February 1998 to coordinate Y2K efforts with the Midcontinent Area Power Pool members and other National Electricity Reliability Council regions. The intent is to facilitate a sharing of information so that work is not duplicated and opportunities to correct problems are not missed. The commission is surveying all regulated electric, gas, and telephone utilities in order to aid the commission is assessing current levels of awareness along with planning and preparation efforts.

Recommendation

The committee recommends House Bill No. 1036 to give the Public Service Commission authority to request from any North Dakota electric, gas, telephone, or pipeline public utility and generation and transmission rural electric distribution cooperative status reports, contingency plans, and information on steps taken by that utility or cooperative to ensure that the state's utilities are addressing the year 2000 computer problem in a timely manner. The bill is effective through July 31, 2001, and contains an emergency clause.