NEW LAW ON ELECTRIC UTILITY REGULATION--THE "RELIABILITY 2000" LEGISLATION (PART OF 1999 WISCONSIN ACT 9)

Information Memorandum 99-6

Wisconsin Legislative Council Staff
One East Main Street, Suite 401
Madison, Wisconsin
Telephone: (608) 266-1304

December 2, 1999
(Revised December 22, 1999)

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INTRODUCTION

This Information Memorandum describes the provisions in 1999 Wisconsin Act 9 (the 1999-2001 Biennial Budget Act), relating to public utility holding companies, electric power transmission, public benefits and other aspects of electric utility regulation. These provisions are commonly referred to as the "Reliability 2000" legislation and are referred to as the "new law" in this Information Memorandum. The new law took effect on October 29, 1999.

Copies of 1999 Wisconsin Act 9 may be obtained from the Documents Room, Lower Level, One East Main Street, Madison, Wisconsin 53702; telephone: (608) 266-2400.

Also available on this topic are two Legislative Council Staff memoranda addressed to Interested Legislators. One provides a shorter overview of the new law and the other provides the text of the new law. This Information Memorandum and the two memoranda to Interested Legislators are available in electronic format at *www.legis.state.wi.us/lc* via links through "Selected Publications" to "Legislative Enactments."

This Information Memorandum is divided into the following parts:

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* The revised version of this Information Memorandum corrects the reported effective dates for: (a) the submission of draft rules to the Legislative Council Rules Clearinghouse by the Department of Administration (DOA) and the Public Service Commission (PSC); and (b) the notification to the DOA by municipal utilities and electric cooperatives on their intentions to implement commitment to community programs.

** This Information Memorandum was prepared by John Stolzenberg, Staff Scientist, and David L. Lovell, Senior Analyst, Legislative Council Staff.

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PART I

HIGHLIGHTS

The new law addresses a wide range of topics relating to electric utilities. Central provisions of the new law do the following:

- Provide a public utility holding company partial relief from limits on nonutility assets it may own if the electric utilities in the holding company system transfer their electric transmission facilities to a separate transmission company which, in turn, transfers operational control of the transmission facilities to the Midwest Independent System Operator (MISO).

- Establish programs and policies intended to improve the siting, construction and operation of the electric transmission system within Wisconsin and between Wisconsin and other states.

- Create a new statutory framework within which to continue and expand public benefit programs relating to: (a) low-income energy assistance; and (b) energy conservation, renewable energy and related topics.

- Limit the real estate-related activities of certain utilities and nonutility affiliates in holding companies.

- Create protections for the employes of utilities and cooperatives and certain affiliates.

- Address future requirements that may be placed on electric utilities and cooperatives relating to the control of nitrogen oxide (NO_x) air pollution emissions.

PART II

ASSET CAP

A. BACKGROUND

The state's public utility holding company law imposes a number of regulations upon public utility holding companies.[1] The holding company law presently applies to a number of holding companies, including the following companies that own major combined electric and natural gas public utilities (their utility affiliates are identified in parentheses): Alliant Energy Corp. (Wisconsin Power and Light Company, IES Utilities Inc. and Interstate Power Company); Wisconsin Energy Corp. (Wisconsin Electric); and WPS Resources Corp. (Wisconsin Public Service Corporation).

The holding company law includes a limit on the amount of assets in nonutility affiliates that a holding company may own. This limit is commonly referred to as the "asset cap." The limit is expressed as a proportion of the utility assets of the holding company system. As implemented by the Public Service Commission (PSC) prior to 1999, these three holding companies may not hold nonutility assets that exceed 25% of their total utility assets.

On August 6, 1999, in response to a petition from Alliant Energy, the PSC established an interim asset cap for Alliant Energy, which is greater than its previous cap of 25% of its utility assets. This interim cap remains in effect until the earlier of either December 28, 1999 (60 days after the effective date of the new law) or the date that the PSC issues a final order in response to Alliant Energy's original petition for asset cap relief.

The holding company law also includes a "grandfather clause," under which a public utility holding company formed before the enactment of the law, which is not itself a public utility, is subject to different treatment than other holding companies. Under this clause, the PSC may impose reasonable terms, limitations or conditions on a grandfathered holding company that are consistent with specific requirements in the law. In practice, the holding company subject to this grandfather clause is WICOR, Inc., the owner of Wisconsin Gas Company.

The PSC has also established a limit on the investments that WICOR may make in nonutility affiliates. Under this limit, WICOR may make capital investments in nonutility operations up to an amount equal to 60% of the total capitalization of WICOR.

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1. In general, a "public utility holding company" is a company which controls 5% or more of the outstanding voting securities of a public utility.

B. ASSET CAP RELAXATION

1. Changes in the Asset Cap Formula

If each public utility affiliate in a holding company system takes the actions specified in Subsection 2., below, with respect to the affiliate's electric transmission facilities, then the new law changes the asset cap for the holding company in the following three ways:

a. ***Eligible assets.*** The "eligible assets" of a nonutility affiliate in the holding company system are excluded from both the sum of the assets of the public utility affiliates and of the nonutility affiliates in the asset cap formula. An "eligible asset" is an asset of a nonutility affiliate that is used for any of the following:

(1) Producing, generating, transferring, delivering, selling or furnishing gas, oil, electricity or steam energy.

(2) Providing an energy management, conservation or efficiency product or service or a demand-side management product or service.

(3) Providing an energy customer service, including metering or billing.

(4) Recovering or producing energy from waste materials.

(5) Processing waste materials.

(6) Manufacturing, distributing or selling products for filtration, pumping water or other fluids, processing or heating water, handling fluids or other related activities.

(7) Providing a telecommunication service.

(8) Providing an environmental engineering service.

All the assets of a nonutility affiliate are considered eligible assets if the bylaws of the nonutility affiliate or a resolution adopted by its board of directors specifies that the business of the nonutility affiliate is limited to activities involving eligible assets and substantially all the assets of the nonutility affiliate are eligible assets.

Collectively, the assets of the nonutility affiliates of the four major holding companies presently include all of the types of eligible assets listed above, though no individual holding company owns all of the types of eligible assets. These holding companies also engage through their nonutility affiliates in other activities, such as real estate-related activities; the assets associated with these activities are not eligible assets.

The effect of this change in the asset cap formula is to remove any asset cap-based restriction on the holding company investments in eligible assets.

b. ***Contributed transmission facility assets.*** The net book value of the transmission facility assets that the public utility contributes to a transmission company as a condition of receiving this treatment of its asset cap (see the second condition in Subsection 2., below) is included in the sum of the assets of the public utility affiliate in the asset cap formula.

In determining the net book value of the contributed transmission assets, accumulated depreciation must be calculated as if the contributing public utility affiliate had not contributed these transmission assets.

This change in the asset cap formula means that the holding company's compliance with its asset cap will not be affected by the specified contribution of transmission facility assets. (The holding company's asset cap will continue to apply to its assets that are not public utility affiliate assets, eligible assets or other exempt assets.)

c. ***Transferred generation assets.*** If the PSC, a court or a federal regulatory agency orders the public utility affiliate contributing transmission assets to the transmission company to transfer generation assets to another person, the sum of these generation assets shall be included in the sum of the assets of the public utility affiliate in the asset cap formula.

In determining the net book value of the transferred generation assets, accumulated depreciation must be calculated as if the transferring public utility affiliate had not transferred these generation assets.

This change in the asset cap formula means that the holding company's compliance with its asset cap will not be affected by the specified transfer of generation assets.

2. Conditions for Relaxation

To be eligible for the three modifications to the asset cap identified in the preceding subsection, each public utility affiliate in the holding company system must do all of the following:

a. ***Operational control of transmission facilities.*** Transfer operational control of all of its transmission facilities in Wisconsin and in neighboring states to the MISO[2] in a two step process. First, the affiliate must petition the PSC and the FERC to approve this transfer. Second, the affiliate must notify the PSC it has become a member of the MISO, has agreed to

2. An independent system operator or ISO is an entity that controls the operation of the transmission facilities of its member utilities and cooperatives and sets regional prices for transmission services on an impartial and coordinated basis, subject to approval by the Federal Energy Regulatory Commission (FERC). The MISO has "functional control" over its members' network transmission system. It's tasks include ensuring the reliability of the transmission system, administering a single system-wide transmission tariff and scheduling transmission service requests. Unlike other ISOs approved by the FERC, the MISO does not physically operate transmission facilities and dispatch generation facilities to balance the load and demand on the transmission system. As of the end of October 1999, the MISO membership included 13 transmission owners with transmission facilities in more than 14 states.

transfer its transmission facilities to the MISO[3] and has committed not to withdraw its membership in the MISO prior to the date on which it contributes transmission facilities to the transmission company.

b. ***Contribution of transmission facilities.*** File with the PSC an unconditional, irrevocable and binding commitment to contribute by September 30, 2000, all of its transmission facilities in Wisconsin and related land rights to the transmission company described in Part III, below. The filing must include a date, no later than September 30, 2000, on which the contribution will be completed.

c. ***Mergers and consolidations.*** File with the PSC an unconditional, irrevocable and binding commitment to contribute, and to cause each entity with which it merges or consolidates or to which it transfers substantially all of its assets to contribute, any transmission facility in Wisconsin it acquires after the effective date of this provision, and the related land rights, to the transmission company.

d. ***Regulatory approvals.*** Petition the PSC and FERC to approve its transmission facility contributions, identified in items b. and c., and agree in the petition not to withdraw the petition if the PSC or FERC conditions its approval on changes that are consistent with state or federal law.

A public utility affiliate that fails to complete the contribution of its transmission facilities to the transmission company by the completion date that it specified in its filing with the PSC shall forfeit $25,000 for each day that completion of the contribution is delayed if the transmission company is legally able to accept the contribution. In addition, a wholesale or retail customer of a public utility affiliate may petition the Circuit Court of Dane County for specific performance of a commitment to contribute transmission facilities and land rights to the transmission company that is filed with the PSC or of a commitment to contribute, and to cause each entity into which it transfers substantially all of its assets to contribute, to the transmission company, any transmission facility in Wisconsin it acquires after the effective date of this provision and the related land rights.

As used in the new law, the "contribution" of transmission facilities to the transmission company means the transfer to the company of the ownership of the facilities and, to the extent permitted by law, associated deferred tax reserves and deferred investment tax credits.

As used in these provisions, a "transmission facility" is any of the following:

3. The new law states that under this requirement the public utility affiliate must notify the PSC that it has agreed to "transfer its transmission facilities" to the MISO. Since this conflicts both with the previous requirement that it petition the PSC and FERC to approve the transfer *of operational control* of its transmission facilities and with the organization of the MISO (the MISO does not own any of its member's transmission facilities), it appears reasonable to interpret this as requiring the affiliate to notify the PSC that it has agreed to transfer the operational control of its transmission facilities to the MISO.

a. A facility that is designed for operation at a nominal voltage of more than 130 kilovolt (kV) and that is not a radial (i.e., terminal) facility.

b. A facility that is designed for operation at a nominal voltage of 50 to 130 kV and that is not a radial facility, unless a person has demonstrated to the PSC that the facility ***is not*** a transmission facility on the basis of the FERC's criteria.

c. A facility that is a radial facility or that is designed for operation at a nominal voltage of 50 kV or less, and a person has demonstrated to the PSC that the facility ***is*** a transmission facility on the basis of the FERC's criteria.

As used in the new law, "land right" is any right in real property, including fee simple ownership or a right-of-way or easement, that has been acquired for a transmission facility that is located or intended to be located on the real property.

3. Treatment of Grandfathered Holding Companies

The new law establishes that the PSC may not impose upon a grandfathered holding company any condition that limits the sum of the holding company's nonutility affiliate assets to less than 25% of the sum of the holding company's utility affiliate assets. The new law also establishes that the PSC's conditions on nonutility affiliate assets of a grandfathered holding company shall not apply to the ownership, operation, management or control of any eligible asset, as defined above in Subsection 1.

PART III

TRANSMISSION COMPANY

The new law authorizes the creation of a transmission company that could potentially own electric transmission facilities throughout the state and in neighboring states. It does not require any public utility to contribute its transmission facilities to the transmission company. However, as noted in Part II, above, the new law does require a public utility affiliate to contribute its transmission facilities to a transmission company with the characteristics set forth in the new law as a condition of relaxing the asset cap that applies to the public utility holding company that owns the affiliate. In addition, the new law does not designate any entity to form the transmission company. Presumably, the utilities with an interest in contributing transmission facilities to the company will take the necessary legal and financial steps to ensure its creation.

A. RESPONSIBILITIES

As used in the new law, the "transmission company" is a corporation or limited liability company that has as its sole purpose the planning, constructing, operating, maintaining and expanding of transmission facilities that it owns to provide for an adequate and reliable transmission system that meets the needs of all users that are dependent on the transmission system and that supports effective competition in energy markets without favoring any market participant.

As a result of the purposes of the transmission company set forth in this definition, a transmission company is a public utility under the definition of "public utility" in s. 196.01 (5), Stats.

The new law assigns a number of specific duties and powers to the transmission company and prohibits it from engaging in certain activities, as described below.

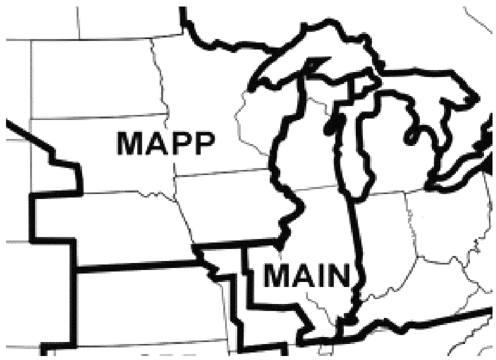
1. Starting Date

The transmission company must apply for any state or federal approvals that are necessary for the company to begin operations no later than November 1, 2000. However, the company may not begin operations until it provides an opinion to the PSC from a nationally recognized investment banking firm that the company is able to finance, at a reasonable cost, its start-up costs, working capital, operating expenses and the cost of any new facilities that are planned.

2. MISO Membership

The transmission company must apply for membership in the MISO as a single zone for pricing purposes that includes the part of the state served by the Mid-American Interconnected Network, Inc. (MAIN), regional council of the North American Electric Reliability Council (referred to as “eastern Wisconsin” in the remainder of this Information Memorandum[4]). The geographic areas served by the two regional electric reliability councils in Wisconsin, MAIN and the Mid-Continent Area Power Pool (MAPP), are depicted in figure 1.

Figure 1
Regional Electric Reliability Councils in Wisconsin



MAPP: Mid-Continent Area Power Pool
MAIN: Mid-America Interconnected Network, Inc.
Source: North American Electric Reliability Council; http://www.nerc.com

Once the PSC determines that the MISO has begun operations, the company must transfer operational control of its transmission facilities to the MISO. The company must remain a member of the MISO or a federally approved successor to the MISO for at least the six-year transition period that is specified in the agreement that establishes the MISO and that the FERC conditionally approved.

In addition, the company must elect to be included in a single zone for the purpose of any tariff administered by the MISO, subject to the phase in of a combined single zone described below.

3. Duty to Provide Transmission Service

After it begins operations, the transmission company shall be the exclusive provider of transmission service in those areas in which transmission facilities have been contributed to it, except for transmission service provided by a public utility or electric cooperative that has an overlapping service territory with the transmission company and has not contributed its transmission facilities to the transmission company. This duty terminates when the MISO begins operations at which time the MISO assumes the exclusive duty to provide transmission service in eastern Wisconsin, except for transmission service provided by a public utility or electric cooperative that has not transferred control over its transmission facilities to the MISO. At that time, the MISO also assumes the responsibility to ensure that each transmission facility in eastern Wisconsin that is under its operational control is planned, constructed, operated, maintained and

4. The statutes refer to this area in eastern Wisconsin as the “transmission area.”

controlled as part of a single transmission system. When the company begins operations, the new law also terminates the duty of any public utility or electric cooperative that has contributed transmission facilities to the company to finance, construct, maintain or operate a transmission facility.

4. Additional Transmission Facilities

The new law specifies that the transmission company may do any of the following:

a. Subject to the PSC's issuance of a certificate of public convenience and necessity (CPCN), the company may construct and own transmission facilities in eastern Wisconsin or in any other area of the state in which transmission facilities have been contributed to the company.

b. Subject to any approval required under state or federal law, the company may purchase or acquire transmission facilities in addition to the transmission facilities that are contributed to it.

5. Operation and Maintenance Contract

Subject to any required state or federal approval, the transmission company must contract with each transmission utility or cooperative[5] that has transferred transmission facilities to the company for the utility or cooperative to provide reasonable and cost-effective operation and maintenance services to the company for three years after the company begins operations. The company and utility or cooperative may, subject to any approval required under federal or state law, agree to extend this three-year period.

6. Assumption of Obligations

The transmission company must assume the obligations of a transmission utility or cooperative that has transferred ownership of transmission facilities to the company under any agreement to provide transmission service over their facilities, or credits for the use of transmission facilities.

7. Single Zone Rate Phase In

If the transmission charges or rates of any transmission utility or cooperative in eastern Wisconsin are 10% or more below the average transmission charges or rates of all transmission

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5. The statutes define the term "transmission utility" to be a public utility or cooperative that owns an electric transmission facility in Wisconsin and provides transmission services in Wisconsin. In this Information Memorandum, any provision in the new law that refers to a "transmission utility" will be described as applying to a transmission utility or cooperative to convey that the provision applies to any electric utility or electric cooperative that owns and operates transmission facilities in Wisconsin. Currently, the only transmission cooperative in Wisconsin is Dairyland Power Cooperative, and it does not own or operate transmission facilities in eastern Wisconsin.

utilities in eastern Wisconsin on the date that the last public utility affiliate files a commitment with the PSC to contribute transmission facilities as a condition of altering its parent holding company's asset cap, then the transmission company must, after consulting with all of the public utility affiliates that have made a commitment to contribute transmission facilities to it, prepare a plan for phasing in a combined single zone rate for the purpose of a pricing network used by users of the transmission system operated by the MISO. The company must also seek plan approval by FERC and the MISO. This plan must phase in an average-cost price for the combined single zone in equal increments over a five-year period except that under the plan, transmission service must be provided to all users of the transmission system on a single-zone basis during the phase-in period.

8. Prohibited Activities

The new law specifies that the transmission company may not do any of the following:

a. Sell or transfer its assets to, or merge its assets with, another person, unless the assets are sold, transferred or merged on an integrated basis and in a manner that ensures that the transmission facilities in eastern Wisconsin are planned, constructed, operated, maintained and controlled as a single transmission system.

b. Bypass the distribution facilities of a public utility or electric cooperative or provide electric service directly to a retail customer or member.

c. Own electric generation facilities or sell, market or broker electric capacity or energy in a relevant wholesale or retail market as determined by the PSC. An exception to this prohibition is provided for when the transmission company is authorized or required by the FERC to procure or resell ancillary services obtained from third parties, engage in dispatch activities that are necessary to relieve transmission constraints or operate a control area.

B. PSC AND FERC JURISDICTION

As a public utility providing transmission services, the transmission company is subject to regulation by both the PSC and FERC. The new law states that the company is subject to the jurisdiction of the PSC except to the extent that it is subject to the exclusive jurisdiction of the FERC. The FERC's jurisdiction includes approving the company's tariffs that set forth rates for and terms and conditions of service prior to the company joining the MISO. The PSC has jurisdiction over activities such as the siting, construction and maintenance of transmission facilities.

The new law exempts the transmission company from certain PSC regulation that it would otherwise be subject to. In particular, the new law removes the requirement for the PSC to approve any issuance of securities by the company. That company is also excluded from the definition of a public utility holding company and, thus, the state public utility holding company law.

The new law also amends current law as it relates to certain transactions between the transmission company and transmission utilities. In particular, any dividends or distributions from the company received by a transmission utility or gain or profit of a transmission utility from the sale or disposition of securities in the company may not be credited by the PSC against the retail revenue requirements of the utility; that is, the benefit of the gain or profit accrues to the utility's stockholders, not its ratepayers. The new law also amends the affiliated interest statute to provide an exclusion from PSC review under that statute for the sale or disposition by transmission utilities of their securities in the transmission company. The PSC must still approve other affiliated interest contracts governing transactions between transmission utilities and the transmission companies, including service contracts.

C. OWNERSHIP

The transmission company will be owned by electric utilities and cooperatives. In addition to public utility affiliates that may contribute transmission facilities as a condition for relaxing their parent holding company's asset cap, the new law also authorizes other electric utilities and electric cooperatives with transmission facilities to transfer their facilities in the geographic area served by the MAPP or MAIN regional electric reliability councils in or out of Wisconsin (see figure 1) to the company in exchange for an equity interest in the company on the same terms and conditions as a public utility affiliate's contribution. Electric utilities that do not own transmission facilities and retail electric cooperatives may also purchase equity interests in the transmission company at a price that is equivalent to net book value and on terms and conditions that are comparable to those for public utility affiliates that have contributed transmission facilities to the transmission company.

One consequence of the new law authorizing these types of owners is that many of the expected owners are likely to also own electric generation facilities. If that proves to be the case, the transmission company will not be an "independent transmission company," as that term is used in state and federal policy-making relating to the restructuring of the electric power industry. Comparable independence of operation is intended to be achieved, however, by the transmission company transferring operational control of its transmission facilities to the MISO.

D. GOVERNANCE

The new law specifies that the operating agreement of the transmission company, if it is organized as a limited liability company, or the bylaws of the transmission company, if it is organized as a corporation, must provide for each of the following:

1. The transmission company has no fewer than five nor more than 14 managers or directors. The company's operating agreement or bylaws may modify this requirement by unanimous vote of the managers or directors during the 10-year period after the organizational start-up date or upon a 2/3 vote of the board after this 10-year period.

2. At least four managers or directors of the company have staggered four-year terms, are elected by a majority vote of the voting security holders of the company and are not directors, employes or independent contractors of a person engaged in the production, sale, marketing, transmission or distribution of electricity or natural gas or an affiliate of such a person.

3. During the 10-year period after the organizational start-up date, subject to the limit on the number of managers or directors in item 1., each security holder of the transmission company may appoint to a one-year term a manager or director of the transmission company under one of the following four provisions:

a. Each security holder that is an investor-owned public utility in eastern Wisconsin that has contributed a transmission facility to the company (a "transmission utility security holder") may appoint one manager or director.

b. Each security holder that receives at least 5% of the voting securities of the company that is a public utility, other than a public utility affiliate, or a generation and transmission electric cooperative that has voluntarily transferred all of its integrated transmission facilities to the company or is a transmission-dependent utility or retail electric cooperative that has purchased an equity interest may appoint one manager or director.

c. Each security holder that is not a transmission utility security holder and that owns at least 10% of the outstanding voting securities may appoint one manager or director. (These requirements may be modified upon a unanimous vote of the managers or directors of the company.)

d. Each group of security holders that do not include transmission utility security holders and that, as a group, owns at least 10% of the outstanding voting securities may appoint one manager or director. (These requirements may be modified upon a unanimous vote of the managers or directors of the company.)

4. During the five-year period after the organizational start-up date, no public utility affiliate that contributes transmission facility assets to the company and no affiliate of such a public utility affiliate may, in general, increase its percentage share of the outstanding securities of the company prior to any initial issuance of securities by the company to any third party. An exception to this limit is provided for an issuance of securities to a third party that is a transmission-dependent utility or retail electric cooperative exercising its right to purchase equity interest in the company at a price that is equivalent to net book value and on terms and conditions that are comparable to those for public utility affiliates that have contributed transmission facilities to the company. This provision does not apply to securities that are issued by the company in exchange for transmission facilities that are contributed in addition to the transmission facilities that are contributed by a public utility affiliate. Furthermore, these requirements may be modified upon a unanimous vote of the managers or directors of the company.

5. Beginning three years after the organizational start-up date, any holder of 10% or more of the company's securities may require the company to comply with any state or federal law necessary for the holder to sell or transfer its share.

E. CONTRIBUTION OF TRANSMISSION ASSETS AND RELATED LAND RIGHTS

The new law specifies a number of detailed terms and conditions that govern the contribution of transmission assets and related land rights from public utility affiliates to the transmission company. In general, these requirements also apply to the contribution of transmission assets by other electric utilities and electric cooperatives to the transmission company.

1. Treatment of Transmission Assets

The new law establishes that, in general, a public utility affiliate may not "contribute" a "transmission facility" (as these terms are defined in Part II, B. 2.) to the transmission company unless the PSC has reviewed the terms and conditions of the transfer for compliance with the requirements in the new law. A PSC order that approves or modifies the terms and conditions of a transfer may allow a public utility affiliate to recover in its retail rates any adverse tax consequences of the transfer as a transition cost.

If a public utility affiliate is making a commitment to contribute transmission facilities to the transmission company in order to modify the asset cap of its parent holding company, then the transmission company and public utility affiliate must structure the transfer of the transmission facility to satisfy the following conditions:

a. The transfer must avoid or minimize material adverse tax consequences to the public utility affiliate that result from the transfer and avoid or minimize the adverse consequences on public utility rates that do not arise out of combining the transmission company's facilities into a single zone in the MISO.

b. To the extent practicable, the transfer must satisfy the requirements of the Federal Internal Revenue Service for a tax-free transfer. If practicable, this requirement shall be satisfied by the transmission company's issuance of a preferred class of securities that provides the fixed cost portion of the resulting capital structure of the transmission company. The transmission company must issue preferred securities under this provision on a basis that does not dilute the voting rights of the initial security holders relative to the value of their initial contributions.

The new law also establishes that, if the transfer of transmission assets by a public utility affiliate results in a capital structure of the transmission company in which the percentage of common equity is materially higher than that of the public utility affiliate that made the transfer, or if the cost of the fixed-cost portion of the capital structure of the transmission company is materially higher than that of the public utility affiliates that made the transfer, then the public utility affiliates must enter into a contract with the transmission company. Under this contract, the public utility affiliates must agree to accept from the transmission company a return on common equity based upon the equity rate of return approved by FERC and upon an imputed capital structure that assigns to a portion of the public utility affiliate's common equity holdings an imputed debt return that is consistent with the requirements of this provision. Public utility affiliates must accept this return on common equity until the FERC determines that the actual capital structure and capital costs of the transmission company are appropriate and consistent with industry practice for a regulated public utility that provides electric transmission service in interstate commerce.

If, at the time that a public utility affiliate files a commitment to transfer its transmission facilities, the public utility affiliate has applied for or obtained a CPCN under s. 196.491 (3), Stats., or a certificate of authority (CA) under s. 196.49, Stats., from the PSC for the construction of a transmission facility, the new law requires the affiliate to proceed with due diligence in obtaining this certificate and in constructing the transmission facility. If the PSC determines that the cost of the transmission facility is reasonable and prudent, the affiliate must transfer these facilities to the transmission company at net book value when the construction is completed in exchange for additional securities of the transmission company on a basis that is consistent with the securities that were initially issued to the affiliate. If the construction of the transmission facility is not completed within three years after the CPCN or CA is issued by the PSC, the transmission company may assume responsibility for completing construction of the transmission facility. If the transmission company assumes this responsibility, it must carry out any obligation under any contract entered into by the public utility with respect to the construction of the transmission facility until the contract is modified or rescinded by the company, to the extent allowed under the contract.

The new law also requires that any transmission facility that is contributed to the transmission company must be valued at net book value, as determined on the basis of the regulated books of account at the time of the transfer.

If a public utility affiliate is not able to contribute its transmission facilities to the transmission company due to merger-related accounting requirements, which is the case for Wisconsin Power and Light Company, the affiliate must transfer the facilities to the company under a lease for the period of time during which the accounting requirements are in effect. Once these requirements are no longer in effect, the affiliate must then contribute the facilities to the company. An affiliate that transfers facilities under a lease under this provision does not qualify its parent holding company for a relaxed asset cap unless, during the term of the lease, the affiliate does not receive any voting interest in the transmission company.

2. Treatment of Land Rights

The new law establishes that if a public utility affiliate commits to contributing land rights to the transmission company as part of a commitment to contribute transmission facilities, then the public utility affiliate must take a number of actions with respect to the contribution of these land rights.

In general, if the land right is assigned to a transmission account for rate-making purposes and is not jointly used for electric and gas distribution facilities by the affiliate, the affiliate must convey at book value all of its interest in the land right to the transmission company, except that any conveyance or assignment under this provision must be subject to the rights of any joint user of the land right and to the right of the public utility affiliate to nondiscriminatory access to the real estate that is subject to the land right.

If the land right is jointly used or intended to be jointly used, for electric and gas distribution facilities by the affiliate, the affiliate must enter into a contract with the transmission company that grants the company a right to place, maintain, modify or replace the transmission company's transmission facilities on the property that is subject to the land right during the life of the facilities and the life of any replacements of the facilities. These rights must be paramount to the right of any other user of the land right except the right granted in the contract shall be on a par with the right of the public utility affiliate to use the land right for electric or gas distribution facilities.

If the public utility affiliate is prohibited from making the conveyance, as described in the preceding paragraph, the affiliate must enter into a contract with the transmission company that grants the company substantially the same rights as under such a conveyance.

The new law establishes that the PSC must resolve any dispute over the contribution of a land right under the above provisions, including a dispute over the valuation of the land rights, unless a federal agency exercises jurisdiction over the dispute. While any dispute is being resolved before the PSC or the federal agency, the transmission company is entitled to use the land right that is the subject to the dispute and is required to pay any compensation that is in dispute into an escrow account.

F. LICENSE FEES AND TAXES

In general, municipal and private "light, heat and power companies" and retail and wholesale electric cooperatives must pay an annual license fee, commonly referred to as the "gross receipts tax," to the Department of Revenue (DOR). The license fee is based upon the product of the company's or cooperative's gross revenues, a statutorily prescribed percentage and a factor that accounts for the portion of the company's or cooperative's total revenue that is earned in Wisconsin. The property of any light, heat and power company and electric cooperative that is subject to the license fee is exempt from general property taxes. In addition, any electric cooperative subject to the license fee is exempt from income and franchise taxes.

The new law establishes that the transmission company is a light, heat and power company, subjecting it to the license fee applicable to private light, heat and power companies. However, the new law provides that the gross revenues of the transmission company exclude revenues for transmission service over its facilities that it provides to municipal public utilities subject to the license fee, public utilities, as defined in public utility law, s. 196.01 (5), Stats., and electric cooperatives organized under ch. 185, Stats. An example of transmission company revenues that will be subject to the license fee are revenues from the transmission of electricity between neighboring states via the transmission company's facilities.

Currently, "sales" not subject to the sales tax include the transfer of property to a corporation or a limited liability company if the transfer occurs when the corporation or company is formed and is paid for through the issuance of the corporation's or company's securities. This exemption applies to the transfer to a transmission company by a utility of its transmission facilities that are above ground and on land not owned by utility (and thus are tangible personal property), if the transfer occurs as part of the organization of the transmission company and is paid for through the issuance of securities in the transmission company. The new law creates a new sales tax exemption that applies to the transfer to the transmission company of transmission facilities (that are on land not owned by the transferor) that are made ***after*** the transmission company is organized and in exchange for securities.

The new law exempts from the real estate transfer fee the conveyance to the transmission company of transmission facilities (that are real property) or land rights in exchange for securities in the transmission company.

PART IV

TRANSMISSION FACILITY SITING, CONSTRUCTION AND OPERATION

The new law contains a number of provisions that are intended to improve the electric transmission system within Wisconsin and between Wisconsin and other states. These provisions: (a) address the operational control of the transmission system; (b) revise transmission facility siting criteria to address concerns over the routing of new high voltage power lines; (c) create payments in lieu of shared revenue aids to local governments that host new transmission facilities; (d) create requirements that maximize the role of the MISO; and (e) expand the authority of the PSC to order construction of needed new transmission facilities. In addition, the new law recognizes that Wisconsin is served by a regional transmission system, and it authorizes the Governor to address the regional planning and siting of transmission lines with other states.

A. TRANSFER OF OPERATIONAL CONTROL

Under 1997 Wisconsin Act 204, each transmission utility or cooperative in Wisconsin must transfer control over its transmission facilities to an independent system operator (ISO) or divest its interest in its transmission facilities to an independent transmission owner (ITO). If a transmission utility or cooperative does not voluntarily transfer or divest its transmission facilities with the applicable state and federal approvals, then the PSC must, by June 30, 2000, order the transmission utility or cooperative to apply to the appropriate federal regulatory agency to do one of the following:

1. Transfer control of the transmission facilities to an ISO that has received federal regulatory agency approval to operate in other states and any part of Wisconsin;

2. Transfer control of the transmission facilities to an ISO that is intended to operate in other states and any part of Wisconsin, if the federal regulatory agency has not approved an ISO to operate in this region; or

3. Divest the transmission utility's or cooperative's interest in its transmission facilities to an ITO if the transmission utility or cooperative does not, or is not able to, to the satisfaction of the PSC, transfer control of its transmission facilities to a proposed ISO under the previous provision.

The new law creates a new exception to the PSC's duty to order the transfer of control or the divestiture of transmission facilities described above. The PSC may not issue this order if the transmission utility or cooperative shows to the PSC's satisfaction that a transfer of its transmission facilities to the MISO may jeopardize the tax-exempt status of the transmission utility or cooperative or its securities under the Federal Internal Revenue Code. This waiver remains in effect until the PSC determines that the proposed transfer does not have this effect.

The new law also requires that each transmission utility in eastern Wisconsin must become a member of the MISO by June 30, 2000 and transfer operational control over its transmission facilities to the MISO. Each of these utilities that has not contributed its transmission facilities to the transmission company, described in Part III, above, must elect to become a part of the single zone for pricing purposes within the MISO, including the phase-in plan applicable to the transmission company.

If the MISO fails to start or ceases operations, the new law requires that the requirements under the new law that apply to the MISO apply to any other ISO or regional transmission organization authorized under federal law to operate in Wisconsin.

B. CPCN FOR TRANSMISSION FACILITIES

No person may commence the construction of a 100 kV or larger high voltage transmission line that is at least one mile in length unless the person has applied for and received a CPCN from the PSC. The new law amends the CPCN review and approval process applicable to these transmission facilities in two ways.

First, it establishes that transmission facilities constructed to increase the transmission import capability into Wisconsin shall use existing rights-of-way to the extent practicable. Routing and design of these facilities must minimize environmental impacts in a manner that is consistent with achieving reasonable electric rates.

Second, the new law establishes that the PSC may not approve a CPCN for construction of any new 345 kV or larger high voltage transmission line without first finding that the line provides usage, service or increased regional reliability benefits to the wholesale and retail utility customers or cooperative members in the state and the benefits of the line are reasonable in relation to its cost.

C. TRANSMISSION LINE IMPACT AND ENVIRONMENTAL FEES

The new law directs the Department of Administration (DOA) to collect two new fees from the owner of any new 345 kV or larger high voltage transmission line. The fees apply if the owner applies to the PSC for the CPCN for the line after October 29, 1999 (the effective date of the new law) or if CPCN was approved by the PSC and filed between April 1, 1999 and October 29, 1999.

One fee is an annual impact fee, set at 0.3% of the cost of the transmission facility, as determined by the PSC. The DOA must distribute the revenue from this fee to municipalities (cities, villages and towns) through which the new transmission line is routed in proportion to the amount of investment in the facility that the PSC allocates to each of these municipalities. The new law does not place any restrictions on the use of these revenues.

The second fee is a one-time environmental impact fee equal to 5% of the cost of the transmission line, as determined by the PSC. The DOA must distribute 50% of the revenue from these fees to counties and 50% to municipalities in proportion to the amount of investment in each county and municipality. These revenues may be used by counties and municipalities for park, conservancy, wetland restoration and other similar environmental programs. The person paying these fees may not use the payment to offset any other mitigation measure required in the PSC's order approving a CPCN for construction of the transmission line.

The owner of a transmission line subject to these fees may recover the fees in rates, as reasonably incurred expenses of providing transmission service.

D. INTERSTATE TRANSMISSION COMPACT

The new law authorizes the Governor, on behalf of the state, to enter into a compact with one or more states in the upper Midwest. The purpose of the compact is to create a joint process for the member states to determine the need for and siting of regional electric transmission facilities that may affect electric service in Wisconsin. If formed, the compact must require compliance with each member state's environmental and siting standards for transmission facilities and provide for a regional determination of the need for transmission facilities and a mechanism to resolve transmission facility siting conflicts between the states.

E. PSC CONSTRUCTION ORDERS

Under 1997 Wisconsin Act 204, the PSC conducted a study on constraints in the intrastate and interstate electric transmission system that adversely affect the reliability of transmission service provided to electric customers in Wisconsin and submitted a report on the results of the study to the Legislature in September 1998. Act 204 also provided that, based on this study, no later than December 31, 2004, the PSC may issue an order requiring an investor-owned electric utility to construct or procure, on a competitive basis, the construction of transmission facilities specified by the PSC that are necessary to relieve a constraint on the transmission system and to materially benefit the customers of the utility, other investor-owned utilities, an ISO or an ITO.

The new law amends this order authority by: (1) removing the December 31, 2004 sunset for the authority; (2) removing the requirement that the order be based upon the results of the September 1998 transmission constraint study; (3) applying the order to the transmission company in addition to investor-owned electric utilities; and (4) changing the PSC authority to issue the order to a duty to issue the order (converting "may" to "shall").

PART V

PUBLIC BENEFITS

Public benefits are goods (or benefits) that are produced by a portion or sector of society but whose benefits flow to society as a whole. A variety of public benefits are produced by the electric power industry and made available to the public at least in part as a result of government regulation. An example of this is the availability to all members of society of a safe, reliable and affordable power supply. In the context of electric utility restructuring generally, and this new law specifically, "public benefits" refers to certain activities that have been performed by electric (and natural gas) utilities for the public good under PSC direction or oversight, specifically, activities to: (a) help make energy affordable to low-income households; (b) promote energy conservation, efficient energy systems and renewable energy sources; and (c) evaluate and mitigate the environmental impacts of energy production and use.

A. PROGRAM ELEMENTS

The new law creates two individual public benefit programs, giving broad grants of authority to the DOA to design and implement them.

1. Low-Income Assistance Program

The new law creates a program for awarding grants to provide assistance to low-income households for weatherization and other energy conservation services, payment of energy bills and the early identification and prevention of energy crises. The program is similar in purpose to the Federal Low-Income Weatherization and Home Energy Assistance Programs. The new law directs the DOA to establish eligibility requirements for the low-income programs by rule. Individuals who receive low-income services under a commitment to community program (described in Section D., below) are not eligible to receive services under the low-income program.

The new law directs the DOA to regulate the amount of grants awarded under this program to ensure that an amount equal to 47% of all low-income public benefit funds expended in this state is expended on weatherization and conservation services. (See Section C., below, for a description of these funds.) Since there may not be sufficient funds in the Utility Public Benefits Fund to accomplish this in the initial years of the program, the new law directs the DOA to specify a schedule for fiscal years (FY) 1999-2000 and 2000-01 for phasing in the requirement.

2. Energy Program

The new law creates a program for awarding grants for energy conservation and efficiency services and for renewable resource programs. The energy conservation and efficiency services portion of the program must give priority to proposals directed at: (a) sectors of the energy conservation and efficiency services market that are least competitive; and (b) promoting environmental protection, electric system reliability or rural economic development. The renewable resources portion of the program must focus specifically on encouraging the development or use of utility customer and electric cooperative member applications of renewable resources, including educating customers and members about renewable resources, encouraging use of renewable resources by customers and members or encouraging research technology transfers. Of the total funds available for energy programs, 4.5% must be expended for the renewable resources portion of the program. In addition, 1.75% must be used for research and development proposals regarding the environmental impacts of the electric industry.

The DOA is directed to establish requirements and grant application procedures for grants by rule. In awarding contracts for energy programs, the administrators may not discriminate against an electric provider, a wholesale electric supplier or an affiliate of one of these solely on the basis of its status as an electric provider, a wholesale electric supplier or an affiliate of one of these.

B. PROGRAM ADMINISTRATION

1. DOA

a. Administration; Contracts

The new law gives principal responsibility for program administration to the DOA, in consultation with the Council on Public Benefits (described below). It directs the DOA to establish each of the program elements after holding one or more public hearings.

The new law directs the DOA to contract with community action agencies, nonprofit corporations or local units of government to provide the low-income program services. It directs the DOA to contract with one or more nonprofit corporations to administer the energy programs. The administrative functions of the energy programs contractor shall include soliciting proposals, processing grant applications, selecting proposals to receive grants (on the basis of criteria specified by the DOA in rules) and distributing grants to recipients. All contracts must be awarded on the basis of competitive bids. The DOA is directed to establish criteria for the selection of a contractor to administer the energy programs by rule.

The new law directs the DOA to annually, beginning in FY 2004-05, determine whether to continue, discontinue or reduce any of the programs related to energy conservation and efficiency and renewable resources. In addition, it must determine the amount of funding necessary for the programs that are continued or reduced. If the DOA determines that the amount of funding necessary for the programs is less than in prior years, it must reduce the amount of new fees for this purpose, described below, accordingly. If the reduction in funding exceeds the amount of new fees for this purpose, the DOA must notify the PSC, which must reduce the amount of continuing funding for this purpose, described below, by this additional amount. The DOA is directed to promulgate rules to establish criteria for determining whether to continue, discontinue or reduce any of the programs. The criteria must include a determination by the DOA of whether the need for a particular program is satisfied by the "private sector market." (The new law does not define this phrase.)

b. Other Duties

The new law directs the DOA to encourage customers to make voluntary contributions to help support public benefit programs. The DOA must promulgate rules to require that electric utilities allow customers to include such voluntary payments with their bill payments. The rules may require special provisions on each bill for this purpose, including the ability of a customer to specify the types of programs for which a contribution is made, and must establish procedures for transferring those contributions to the specified programs.

The new law requires that the DOA annually provide for an independent audit and submit a report to the Legislature describing the expenses of administering the public benefit programs, the effectiveness of the programs and any other topics identified by the DOA, the Council on Public Benefits, the Governor, the Speaker of the Assembly or the Majority Leader of the Senate.

c. Rule Making

The new law directs the DOA to promulgate rules on various topics, which are described in this Information Memorandum along with the related subject matter. In each case, it directs the DOA to promulgate the rules as emergency rules and to submit draft final rules to the Legislative Council Rules Clearinghouse for review by April 1, 2000.

2. Council on Public Benefits

The new law creates a Council on Public Benefits ("the Council"). The new law does not assign any specific powers or duties to the Council, but directs the DOA to execute its duties in administering the public benefit programs in consultation with the Council. The Council consists of the following 11 members:

a. Two members selected by the Governor.

b. Two members selected by the Senate Majority Leader.

c. One member selected by the Senate Minority Leader.

d. Two members selected by the Speaker of the Assembly

e. One member selected by the Assembly Minority Leader.

f. One member selected by the Secretary of the Department of Natural Resources.

g. One member selected by the Secretary of the DOA.

h. One member selected by the Chairperson of the PSC.

The members of the Council serve for three year terms. Their appointments are not subject to confirmation by the Senate. The new law does not specify any qualifications for the members nor does it require the appointing authorities to coordinate their appointments in any way to ensure a balance of expertise or points of view on the Council. The Council is attached to the DOA for administrative purposes.

C. FUNDING FOR PUBLIC BENEFIT PROGRAMS

The new law relies on three sources of funds for the public benefits programs: funds that major investor-owned public utilities have been collecting through rates to pay for public benefit programs conducted under PSC oversight or direction; new fees that electric public utilities and retail electric cooperatives are required to collect through rates and remit to the state; and federal funds provided for low-income energy assistance and weatherization programs. Estimates of the funding levels and the amount of fees are presented in the appendix.

1. Continued Major Utility Revenue

The new law directs the PSC to determine the amount that each major investor-owned electric or gas utility spent in 1998 on public benefit programs related to low-income assistance, energy conservation and efficiency, environmental research and development and renewable resources. It requires these utilities to continue to collect these amounts through rates. It directs the PSC to devise a scheme to, in 2000, 2001 and 2002, phase the expenditure of these revenues out of the utilities' public benefit programs and into the programs administered by the DOA. Beginning in 2003, the utilities are required to contribute the entire amount to the DOA programs. The PSC is required to reduce the amount of funds raised by this mechanism if the DOA reduces the required funding level of the energy public benefit programs, as described in Section B. 1. a., above. Utilities may elect to continue their own public benefit activities, in addition to raising funds for the state programs.

2. New Fees

The new law establishes separate fees for investor-owned utilities and for municipal utilities and cooperatives. Except in the case of commitment to community programs, described below, the utility or cooperative must remit the fee revenues to the DOA.

a. Fees Collected by Investor-Owned Utilities

The DOA is required to set the fees collected by investor-owned utilities by rule. The fees are to be flat fees, not based on the amount of electricity used by the customer, but they may vary between customer classes. Seventy percent of the revenues collected by any utility must be from fees charged to residential customers and 30% must be from nonresidential customers. Through June 30, 2008, the total amount of fees paid by an individual customer is capped such that the fee will not exceed 3% of all other charges for which the customer is billed or $750 per month, whichever is less.[6] Utilities must include the fee in the fixed charges for electricity in customers' bills (as opposed to presenting the fee as a separate line in the bill) and provide customers with an annual statement that identifies annual charges and describes the programs for which they are used. Utilities are allowed to recover, as part of the fees, reasonable and prudent expenses they incur in collecting the fees.

(1) Fees for low-income programs

The fees collected by investor-owned utilities must be designed to raise specified amounts to fund low-income and energy programs. The total amount raised in FY 1999-2000 for low-income programs is calculated in two steps. First, the DOA must subtract from $24 million 1/2 of the amount raised in fees collected by municipal utilities and cooperatives for low-income programs. Then the DOA must reduce this amount in proportion to the length of time that elapses in that fiscal year before the DOA promulgates the rules setting the amount of the fees.

In subsequent years, the low-income fees are established in a formula that involves a number of calculations. The formula is designed to ensure that the total level of funding for low-income programs, from all sources, is the same proportion of a given year's low-income need as is provided in the base funding of the program; the fees are set to raise the portion of this funding that is not provided from other sources. First, the "low-income need" for the fiscal year is calculated. This is the amount by which the annual energy bills of all low-income households in the state exceed 2.2% of the annual incomes of those households. This is a measure of the amount of those energy bills that are unaffordable to those households and so is a measure of the need for program funding.

Next, the total amount of low-income program funding for the fiscal year (referred to as the "low-income need target") is determined by multiplying the low-income need by a factor called the "low-income need percentage." This factor is the percentage of low-income need in FY 1998-99 that is represented by the total base funding specified in the new law. The base funding is the sum of the federal funds received in FY 1997-98, the low-income fees collected by investor-owned utilities for FY 1999-2000 (***before*** this amount is reduced to reflect the delayed start of the program), the amount the major investor-owned electric and natural gas utilities spent on low income programs in 1998, and 50% of the amount of public benefit fees collected by municipal utilities and retail electric cooperatives in FY 1999-2000.

The amount of revenue that must be raised through low-income fees is then determined by subtracting from the total low-income program funding each of the other three funding sources for the fiscal year: federal funds; continuing major utility funding; and 50% of the fees

6. To implement this provision as written, the DOA would need to know both the amount of fees and the total of all other charges that customers will be billed through June 30, 2008, which is not possible. One option available to the DOA is to project these amounts and make adjustments in later years, as necessary. Another option, which may deviate from a strict reading of the new law, is to ensure that the amount of the fee collected in any one billing cycle not exceed 3% of all other charges in that billing cycle.

collected by municipal utilities and retail electric cooperatives. The fees are then set to raise this amount.

The DOA is required to determine the low-income need target for each fiscal year after FY 1998-99. It is directed to establish a method, by rule, for estimating the total of low-income energy bills, the average annual income of low-income households and the number of low-income households in this state in a fiscal year, for the purpose of determining the amount of low-income need in that fiscal year.

(2) Fees for energy programs

The total amount raised for energy programs must be $20 million minus 1/2 of the amount raised in fees collected by municipal utilities and cooperatives. Again, for FY 1999-2000, the DOA must reduce this amount in proportion to the length of time that elapses in that fiscal year before the DOA promulgates the rules setting the amount of the fees. Beginning in FY 2004-05, the DOA is required to reduce the amount of funds raised by this mechanism if it reduces the required funding level of the energy public benefit programs, as described in Section B. 1. a., above.

b. Fees Collected by Municipal Utilities and Cooperatives

The new law requires that municipal utilities and cooperatives collect fees from their customers that average $16 per electric meter per year. They may charge different fee levels for different customer classes. Again, the total amount of fees paid by an individual customer or member through June 30, 2008 may not exceed 3% of all other charges for which the customer or member is billed or $750 per month, whichever is less. As with fees collected by investor-owned utilities, for FY 1999-2000, municipal utilities and cooperatives must reduce the amount of fees in proportion to the length of time that elapses in that fiscal year before the DOA promulgates the rules setting the amount of the fees for investor-owned utilities. The DOA is required to provide advice to municipalities and cooperatives regarding the amount of this reduction.

3. Federal Revenue

The third source that the new law relies upon for public benefit funding is existing federal funding under the Low-Income Weatherization Assistance and Low-Income Home Energy Assistance Programs. The new law essentially views state and federal low-income programs as two sources of funding for the same purpose. As was described in the preceding description of fees, the amount of federal revenues received by this state is part of the formula used to set the fees. However, the administration of the federal funds is maintained as a separate program.

4. Tax Treatment of Fee Revenues

The new law establishes that the following revenues are excluded from the gross revenues of an electric utility or a retail or wholesale electric cooperative and thus are excluded from the calculation of the utility's or cooperative's license fee (the "gross receipts tax"):

a. Public benefit fees collected by an electric utility or retail electric cooperative.

b. Public benefit fees received by a "wholesale supplier" (e.g., Dairyland Power Cooperative or Wisconsin Public Power, Inc.) from a municipal electric utility or a retail electric cooperative or under a joint commitment to community program (described below).

c. Public benefit fees received by a municipal electric utility or a retail electric cooperative from such a utility or cooperative under a joint commitment to community program.

The new law also exempts public benefit fees collected by an electric utility or a retail electric cooperative from the sales tax.

5. Transfer to the Air Quality Improvement Program

If the Air Quality Improvement Program authorized by the new law is created, the DOA must transfer money from the appropriation for the public benefit energy program to fund grants under the Air Quality Improvement Program. This transfer is described in Part VI, B. 2., below. The effect of a transfer would be to reduce the amount of funds available for energy programs by the amount of the transfer.

D. COMMITMENT TO COMMUNITY PROGRAMS

The new law gives municipal utilities and cooperatives the option to implement all or part of the public benefit programs for their customers in programs referred to as commitment to community programs. They may implement such programs individually or jointly with other municipal utilities or cooperatives. If a municipal utility or cooperative chooses to implement both the low-income and energy components of the public benefit program, it retains all of the revenues from the fees it collects and uses them for those purposes; if it chooses to implement one but not both components, it retains 1/2 of the revenues for its program and remits the other 1/2 to the state for the state program; if it chooses not to implement a commitment to community program, it remits all of the fee revenues to the state.

By October 1, 2000, and every three years thereafter, each municipal utility or cooperative must notify the DOA whether it intends to implement a commitment to community program. Once it has chosen to do so, it must continue the program for a period of three years.

If a municipal utility or cooperative that implements a commitment to community program is served by a wholesale electric supplier that has established a low-income assistance program or an energy conservation program, it may treat a portion of the revenues that the supplier spends for that program toward its required expenditures under its commitment to community program. The municipal utility or cooperative may claim a credit in proportion to its purchases from the supplier.

A municipal utility or cooperative that implements a commitment to community program must annually submit a report to the DOA regarding its program. The report must provide an accounting of fees charged to customers, program expenditures and credits claimed for the programs of a wholesale electric supplier. In addition, it must provide a description of the program. The DOA is required to retain the reports for at least six years.

E. RENEWABLES PORTFOLIO STANDARD

One policy mechanism for promoting the implementation of renewable energy resources is the renewables portfolio standard (RPS). An RPS is a requirement that suppliers of electric power include in their portfolio of generation facilities a specified amount or proportion of generation capacity that relies on renewable energy resources.

The new law requires that an electric provider (defined as a retail electric utility or a retail electric cooperative) provide the following proportions of its total retail energy sales in the form of renewable energy:

1. By December 31, 2001, 0.5%.
2. By December 31, 2003, 0.85%.
3. By December 31, 2005, 1.2%.
4. By December 31, 2007, 1.55%.
5. By December 31, 2009, 1.9%.
6. By December 31, 2011, 2.2%.

The new law considers the following sources of electricity to be renewable energy:

1. A fuel cell that uses a fuel determined by the PSC to be renewable.
2. Tidal or wave action.
3. Solar thermal electric or photovoltaic energy.
4. Wind power.
5. Geothermal technology.
6. Biomass.

7. A hydroelectric facility with a capacity of less than 60 megawatts.

8. Any other resource, other than a conventional resource, designated as a renewable resource by the PSC by rule. ("Conventional resource" is defined as a resource that derives energy from coal, oil, nuclear power or natural gas, except for natural gas used in a fuel cell.)

For purposes of determining compliance with the RPS, an electric provider's retail energy sales are calculated on the basis of an average of the energy sales over the preceding three years. In calculating the total renewable energy it sells, an electric provider may include energy from renewable facilities in this or another state and renewable facilities on its or another electric provider's system. In addition, it may include energy from renewable facilities that are installed or operated to comply with federal law but it may ***not*** include energy from renewable facilities that are installed or operated to comply with the laws of another state, even if they are also installed or operated to comply with federal law.

If a facility burns a biomass fuel along with conventional fuel, the amount of renewable energy produced by that facility is considered to be the same proportion of the total energy capacity of the facility as the proportion of the energy input provided by the biomass fuel.[7]

The new law limits the amount of electricity derived from facilities that were placed in service and generating electricity from hydroelectric power before January 1, 1998 that may be counted toward meeting the requirement for providing renewable energy. An electric provider may not count more than 0.6% of its total capacity from such sources toward meeting the requirement, even if the output of such a facility is used to satisfy the requirements of federal law.

An electric provider is allowed to comply with the RPS in either or both of two ways. First, it may generate or purchase the electricity from renewable resources. Second, it may purchase credits from another electric provider that has generated the credit by providing its customers or members electricity from renewable sources in excess of the amount required under the standard. The PSC is required to promulgate rules to establish requirements for the use of credits, including calculating the amount of credits. It is directed to promulgate the rules as emergency rules and to submit draft final rules to the Legislative Council Rules Clearinghouse for review by April 1, 2000. The PSC is authorized to promulgate rules establishing requirements and procedures for the sale of credits, although it may not place restrictions on the sale price negotiated by the parties.

In addition, the new law provides that members of a municipal electric company (a wholesale supplier to municipal retail electric utilities, e.g., Wisconsin Public Power, Inc.) may aggregate and allocate renewable energy among themselves for purposes of determining compliance with the RPS.

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7. The formula for this calculation may not work as drafted, since it compares the energy content of fuels to the maximum capacity of the facility, rather than the actual output of the facility.

The RPS does not apply to an electric provider that provides more than 10% of its summer peak demand ***in this state*** from renewable facilities, ***excluding*** renewable facilities that are installed or operated to comply with another state's RPS. Also, the RPS does not apply to an electric provider that provides more than 10% of its ***total*** summer peak demand from renewable facilities, ***including*** renewable facilities that are installed or operated to comply with another state's RPS. In determining whether either of these exemptions apply to it, an electric provider may include renewable facilities in this or another state and renewable facilities on its or another electric provider's system.

The new law requires each electric provider to submit an annual report to the DOA documenting its compliance with the RPS. It also requires that the PSC allow utilities to fully recover the cost of complying with the standard through their rates. A utility may recover the costs by allocating the costs equally to all customers on a kilowatt hour basis, through alternative pricing structures, including pricing structures under which customers pay a premium for renewable energy, or any combination of these methods.

The Attorney General is directed to enforce the standard. A person who violates the standard or submits a false or misleading certification regarding the source or amount of energy provided to an electric provider is subject to a forfeiture of not less than $5,000 nor more than $500,000. In imposing a forfeiture, the court is directed to consider the appropriateness of the forfeiture to the volume of the person's business, the gravity of the violation and whether a violation of the standard was beyond the person's control.

PART VI

NO_x EMISSIONS

The Federal Clean Air Act, as amended, establishes the federal framework for controlling air pollution in the United States. The act directs the Administrator of the Environmental Protection Agency (EPA) to promulgate national "ambient air quality standards" for various air pollutants. Each state is required by the act to prepare and implement, subject to EPA's approval and oversight, a "state implementation plan" (SIP) that designates control strategies for the various sources of a pollutant subject to a national standard, or the precursors of such a pollutant, that are necessary to reduce the level of the pollutant to at least the level of the standard. The EPA's requirement that a state prepare or revise a SIP is referred to as a "SIP call."

The new law contains two separate initiatives relating to a SIP that requires reductions in NO_x emissions. (Nitrogen oxides, referred to by the chemical symbol NO_x, are precursors to the formation of atmospheric ozone, which is subject to a national standard.) One of the initiatives has general applicability; the second only applies under a narrow set of circumstances if a specific SIP call is issued, as described below.

A. TRADING PROGRAM FOR NO_x EMISSIONS CREDITS

The new law directs the DNR to authorize air pollution sources to participate in a market-based trading program for the purchase, sale and transfer of credits for reducing NO_x emissions for use in any SIP that requires reductions in NO_x emissions. Under this provision, the DNR may require use of a trading program that it creates or one that has been created by another entity. To the extent allowed under federal law, the DNR must allow NO_x emission reductions to be purchased, sold or transferred under the program by any air pollution source in Wisconsin, regardless of whether the source is subject to NO_x controls under any SIP.

B. SIP CALL TO CONTROL ATMOSPHERIC OZONE IN OTHER STATES

On October 27, 1998, the EPA published a SIP call affecting 22 eastern states and the District of Columbia. This call required these jurisdictions to submit SIPs to the EPA by September 30, 1999 that addressed the interstate transport of atmospheric ozone through reductions in NO_x emissions. The SIP call specified statewide reductions in NO_x emissions and encouraged an allocation of these reductions among electric power plants owned by electric utilities and cooperatives and other major industrial sources (e.g., large paper mill boilers).

Following the EPA's promulgation of the SIP call, several states and industry organizations asked the U.S. Court of Appeals for the D.C. Circuit to overturn the call. They argued that the SIP call is not supported scientifically and violates the Clear Air Act. Since the court was not expected to rule on this challenge until after the September 30, 1999 submittal date, Michigan and West Virginia petitioned the court to delay the submittal deadline. On May 25, 1999, the court stayed the date on which SIPs under this call were due at the EPA. This action had the effect of suspending the development and implementation of SIPs in response to this SIP call until after the court issues its final order in this case. As of the writing of this Information Memorandum, the court has not issued its final order.

The new law includes two provisions that take effect only if the court's final ruling allows the EPA to implement either the original SIP call or a modified version of it and as a result of EPA's SIP call the DNR issues a SIP that requires electric power plants in western Wisconsin to comply with NO_X emission reduction requirements. If those events occur, then the new law does the following: (1) it places limits on the NO_X emission reductions that the DNR may require under this SIP; and (2) it creates an air quality improvement program to provide grants to operators of electric power plants in western Wisconsin that help pay for NO_X emission reductions at these plants. In addition, it requires that the DNR notify the DOA and PSC that it has issued this SIP and the date that the electric power plants in western Wisconsin must comply with NO_X emission reduction requirements.

1. Limits on NO_X Emission Reduction Requirements

If the DNR establishes NO_X emission reductions under the conditions specified above, then the new law specifies that these reductions must comply with all of the following:

a. The reductions must allow at least the following amounts of total NO_X emissions each summer from the specified sources:

(1) 2,234 tons from all electric power plants located in northwestern counties that are owned by electric cooperatives (i.e., Dairyland Power Cooperative).

(2) 315 tons from all electric power plants located in northwestern counties that are owned by electric utilities (i.e., Northern States Power Company-Wisconsin).

(3) 15,157 tons from all electric power plants located in other counties that are owned by public utilities or electric cooperatives (i.e., electric utilities located in eastern Wisconsin).

(The total of these amounts is larger than the total for these sources specified in the initial, default federal regulations accompanying the SIP call by 866 tons of NO_X emissions.)

b. The DNR may not, based on these provisions, require additional NO_X emission reductions from any mobile source (e.g., cars and trucks) or any stationary source in Wisconsin that is not an electric power plant owned by an electric utility or cooperative.

c. The DNR must ensure that at least 866 tons of total annual reductions in NO_X emissions required under the SIP be achieved through any of the following:

(1) The use of renewable energy. This use may include renewable energy that is provided by electric providers complying with the RPS created by the new law or that is used under public benefit programs created and funded by the new law.

(2) The implementation of low-income weatherization and energy conservation measures. These measures may include public benefit programs created by the new law or existing utility public benefit programs.

The new law does not coordinate or link the NO_x emission reductions to be achieved through the use of renewable energy and low-income weatherization and energy conservation measures with the allowable electric power plant emissions specified above.

If the DNR implements the SIP in a manner that requires less NO_x emission reductions than those set forth in the EPA's October 27, 1998 SIP call, then the new law directs the DNR to do each of the following:

a. Increase the annual NO_x emission floors for electric power plants specified above to reflect the lower reductions and relax any related emissions control requirements in a manner that reflects the lower reductions.

b. Determine the amounts by which the sources of funds for the air pollution control grants, described below, should be decreased to reflect the lower reductions and provide notice, as appropriate, of the decreased amounts to the PSC and DOA.

2. Air Quality Improvement Program

If the DNR notifies the DOA that it has issued a SIP in response to the EPA's SIP call, described above, that requires electric power plants in western Wisconsin to comply with NO_x emission reduction requirements, then the DOA must award grants to operators of electric power plants in western Wisconsin. The purpose of the grants is to support compliance with requirements under state or federal law to reduce NO_x emissions in western Wisconsin pursuant to a SIP. The DOA must promulgate rules for awarding these grants that include the requirement that an applicant for a grant must identify the reduction in NO_x emissions that the applicant is capable of achieving with the grant.

The grants are awarded annually for 10 years commencing in the fiscal year ending before the compliance date specified in the DNR's notice to the DOA. The total amount of grants awarded each year is $4.9 million. The DOA must reduce this amount if the DNR has notified it that lesser grants shall be awarded as a result of the EPA requiring less NO_x emission reductions than in its original October 27, 1998 SIP call. The new law specifies that the eligible public utility, Northern States Power Company-Wisconsin, may receive no more than $500,000 per year in grants. Dairyland Power Cooperative, the other eligible recipient of grants, may be awarded the remaining funds.

These grants are funded by two sources. One is a transfer by the DOA of $2.5 million per year for 10 years from the appropriation for energy conservation and efficiency and renewable resource grants under the public benefit programs created by the new law. The second source is an assessment by the PSC against electric public utility affiliates (Wisconsin Power and Light Company, Wisconsin Electric and Wisconsin Public Service Corporation). This assessment totals $2.4 million per year and last 10 years. The amount of the assessment against each of these affiliates must be proportionate to the affiliate's "heat throughput" (i.e., energy content of the consumed fuel) for its fossil fuel power plants for the prior fiscal year compared to the heat throughput for all of the affiliates' fossil fuel power plants. The amounts of both the transfer and the assessment must be decreased in accordance with the notice from the DNR that lesser amounts are needed for the grants under the program.

The new law establishes that grants awarded under this program to an electric utility or cooperative are excluded from the gross revenues of the utility or cooperative and are thus excluded from the calculation of the utility's or cooperative's license fee (or "gross receipts tax," further described in Part III, F.).

PART VII

REAL ESTATE-RELATED ACTIVITIES

The new law specifies prohibited real estate-related activities of public utilities and nonutility affiliates and exceptions to these prohibitions. In these provisions, a "public utility" is an investor-owned electric utility, and a "nonutility affiliate" is a subsidiary of a public utility or a company in a "holding company system," as defined in the state's public utility holding company law, that is not a public utility. "Nonutility affiliate" does not include a "passively held company." A "passively held company" is an entity for which less than 50% of the ownership interest is directly or indirectly owned in any chain of successive ownership by a public utility or nonutility affiliate and that engages in property management for a third party, real estate practice, residential real estate development or residential or commercial construction.

A. PROHIBITED ACTIVITIES

The new law establishes that, except as noted below, a public utility or a nonutility affiliate may not do any of the following in Wisconsin:

1. Engage in real estate practice, including being a real estate broker.

2. Engage in residential real estate development.

3. Engage in property management for a third party.

4. Engage in residential or commercial construction.

The new law defines the terms used in these prohibitions. "Residential real estate development" is the act of dividing or subdividing any parcel of land for residential construction or making improvements to facilitate or allow residential construction. "Property management" is an activity associated with the care or maintenance of land or improvements on the land. "Residential construction" is the act of building part or all of a structure that is used as a residence by one or more persons maintaining a common household to the exclusion of all others. "Commercial construction" is the act of building part or all of a structure that is not used as a residence. "Engage" is to actively participate in the daily operations or daily business decisions of an entity, excluding taking an action necessary to protect an ownership interest in an entity.

B. EXCEPTIONS

Notwithstanding the prohibitions identified above, the new law establishes that it does not prohibit a public utility or nonutility affiliate from doing any of the following:

1. Repairing, maintaining, installing or constructing a structure that is owned or used by or for a public utility or nonutility affiliate, or for a customer of a public utility, if the repair, maintenance, installation or construction is related to furnishing heat, light, water or power to the customer.

2. Engaging in any construction related to the evaluation, control or remediation of a hazardous substance; solid, liquid or gaseous wastes; soils; air; or water.

3. Engaging in any construction performed in order to comply with federal, state or local environmental laws, regulations, orders or rules.

4. Consulting or making other financial or business arrangements with one or more third parties who will engage in commercial construction.

5. Consulting or making other financial or business arrangements with one or more third parties who will engage in residential construction or residential real estate development, except that if a public utility or nonutility affiliate contracts for the development of more than one residential construction project or residential real estate development, the utility or affiliate may not enter into an exclusive arrangement with a third party for all of these projects or developments.

6. Acquiring or disposing of property or interests in property if the acquisition or disposition is related to the operation of a public utility and is conducted either under a contract with a third party that is engaged in real estate practice or by an individual engaged in real estate practice or employed by a public utility.

7. Owning a passively held company, as defined in the introduction to this Part of the memorandum.

In addition, the new law authorizes a public utility or a nonutility affiliate to engage in residential real estate development at a brownfields facility or site. As used in the provision, a "brownfields facility or site" is any abandoned, idle or underused industrial or commercial facility or site, the use, expansion or redevelopment of which is adversely affected by actual environmental contamination.

The new law specifies that it does not prohibit a public utility that is not subject to the public utility holding company law (e.g., Northern States Power Company-Wisconsin and Madison Gas and Electric Company) or a nonutility subsidiary of such a public utility from doing any of the following:

1. Engaging in commercial or residential real estate development or construction on property owned or acquired by the public utility or nonutility subsidiary for a public utility purpose if the total annual revenues from the development or construction do not exceed 3% of the total operating revenues of the public utility in any year.

2. Providing financial support (e.g., investments, loans or grants) for the purpose of economic development to third parties that are engaged in one of the prohibited activities. The public utility or nonutility subsidiary may profit directly from that activity only through the receipt of profits that are incidental to the economic development project or interest earned on a loan.

The new law establishes that a nonutility affiliate that has engaged in residential construction prior to, or is engaged in residential construction on the effective date of this provision (i.e., Heartland Properties, Inc., a nonutility affiliate of Alliant Energy Corporation), may directly or indirectly own in any chain of successive ownership 50% or more of the ownership interest of an entity that hires a third party to engage in residential construction or commercial construction that is incidental to residential construction. The nonutility affiliate may not actively participate in the daily operation or daily business decisions of the entity under this provision.

C. PRIVATE CAUSE OF ACTION

The new law establishes that any public utility or nonutility affiliate that does, causes or permits to be done any action prohibited under the new law or fails to comply with any requirement specified in the new law is liable to any person injured by that action in the amount of damages sustained in consequence of the prohibited action or failure to comply.

PART VIII

ENERGY AFFILIATE AND UTILITY EMPLOYE PROTECTIONS

The new law establishes that no person may sell an "energy unit" of a public utility, cooperative, holding company system or nonutility affiliate unless the person has satisfied the following conditions relating to nonsupervisory employes who are employed with the energy unit immediately prior to the transfer:

a. The terms of the transfer require the person to which the unit is transferred to offer employment to those employes who are employed with the unit immediately prior to the transfer and who are necessary for the operation and maintenance of the energy unit.

b. The employment that is offered under the preceding requirement must satisfy each of the following requirements during the 30-month period beginning immediately after the transfer: (1) wage rates must be no less than the wage rates in effect immediately prior to the transfer; (2) fringe benefits must be substantially equivalent to the fringe benefits in effect immediately prior to the transfer; and (3) terms and conditions of employment, other than wage rates and fringe benefits, must be substantially equivalent to the terms and conditions in effect immediately prior to the transfer. These requirements may be modified or waived by a collective bargaining agreement.

If the transaction involves a public utility affiliate selling an energy unit to a nonutility affiliate in the same holding company system, the terms of the transfer must require the nonutility affiliate to offer employment under the specified terms to all of the nonsupervisory employes who are employed with the energy unit immediately prior to the transfer.

If the transaction involves a transmission utility or cooperative selling an energy unit (i.e., a transmission facility) to the transmission company, at the end of the required operation and maintenance contract (described in Part III, D.), the transmission company must offer employment under the specified terms to the nonsupervisory employes who are employed with the energy unit immediately prior to the transfer and are necessary for the operation and maintenance of the energy unit.

The new law requires that, except for a sale of an energy unit by a cooperative or by a transmission utility or cooperative to a transmission company, no person may sell an energy unit unless the PSC determines that the person has satisfied the conditions listed above.

As used in these provisions, an "energy unit" is a division, department or other operational business unit in Wisconsin of a nonutility affiliate, holding company system, public utility or cooperative that is engaged in activities related to the production, generation, transmission or distribution of electricity, natural gas or steam or the recovery of energy from waste materials.

PART IX

OTHER PROVISIONS

A. ELECTRIC SYSTEM RELIABILITY

1. Reliability Status Reports

The new law directs the PSC to require, by rule, that electric utilities and cooperatives that own large power plants or transmission facilities report to the PSC, as frequently as the PSC determines to be reasonably necessary, on their current reliability status. These reports shall include information on operating and planning reserves, available transmission capacity and outages of major generation units and transmission facilities. These reports shall be open to public inspection and copying, except that the PSC may delay public access for a reasonable time to prevent an adverse impact on the supply or price of energy in Wisconsin.

2. PSC Construction Orders

The new law also directs the PSC to order any public utility affiliate (i.e., Wisconsin Electric, Wisconsin Power and Light Company or Wisconsin Public Service Corporation) or the transmission company to make adequate investments in its facilities that are sufficient to ensure reliable electric service. The PSC must make this order if it determines that a public utility affiliate or the transmission company is not making investments in the facilities under its control that are sufficient to ensure reliable electric service. This order must require the affiliate or company to provide security in an amount and form that, to the PSC's satisfaction, is sufficient to ensure that the affiliate or company expeditiously makes any investment that is ordered. The PSC must allow an affiliate that is subject to an investment order to recover in its retail electric rates the costs that are prudently incurred in complying with the order.

B. OTHER HOLDING COMPANY REGULATIONS

1. Utility Capital Structure

Under the state's holding company law, the PSC must consider the public utility affiliate of a holding company as a wholly independent corporation when the PSC makes any determination on any rate change proposed by the affiliate. The new law expands this requirement and directs the PSC, when making this determination, to impute a capital structure to the public utility affiliate and establish a cost of capital for the public utility affiliate on a stand-alone basis.

2. Triennial PSC Investigation

The holding company law directs the PSC to triennially investigate the impact of the operation of every holding company system formed under the law on every public utility affiliate in the holding company system. As part of this investigation, the PSC must determine whether each nonutility affiliate does, or can reasonably be expected to do, at least one of several specified activities. These activities include promoting economic development, energy conservation or renewable energy products, developing or acquiring energy resources, engaging in a business's function related to the provision of utility service, or developing industrial parks. The new law specifies that this investigation does not apply to the nonutility affiliates in a holding company that were affiliates of a holding company that was formed before the effective date of the holding company law, November 28, 1985. (If the proposed acquisition by Wisconsin Energy Corporation of WICOR is completed, then this provision would apply to the nonutility affiliates that were part of WICOR prior to the merger.)

C. STUDIES

1. Market Power

The new law directs the PSC to contract with an expert economic consultant for a study on the potential of horizontal market power (including market power in the area of generation of electricity) to frustrate the creation of an effectively competitive retail electricity market in the state. The study must include recommendations of measures to eliminate such market power on a sustainable basis. For each recommendation made, the report shall include an assessment of the effect on utility workers, on utility shareholders and on the rates of each class of utility customers. The study must include an evaluation of the impact of transmission constraints on generation market power in local areas. The PSC is required to submit a report to the Legislature based on the study not later than January 1, 2001.

2. Incentives for Distributed Energy Systems

The new law directs the PSC, in consultation with the DOA and DOR, to study the establishment of a program of incentives for the development of highly efficient, small-scale generating facilities in the state. The program studied shall either: (a) provide benefits in the form of support for the transmission and distribution system, power quality or environmental performance; or (b) employ technologies, such as combined heat and power systems, fuel cells, microturbines and photovoltaic systems, that can be situated in, on or adjacent to buildings or other electric load centers. The PSC must report its study findings and recommendations to the Legislature by January 1, 2001.

D. MARKET-BASED PRICING

The new law directs investor-owned utilities that generate, distribute and sell electricity to offer market-based rates to customers. They must offer: (1) rates that result in customers receiving market-based compensation for voluntary interruption of firm load during peak demand; and (2) market-based pricing and individual contract options that allow customers to receive market benefits and subject themselves to market risks in purchasing capacity or energy from the customer's existing public utility. The new law directs the PSC to approve market-based rates that are consistent with such market-based pricing options and individual contract options, except that it may not approve such rates if the rates will harm the utility's shareholders or customers who are not subject to the rates. Municipal utilities are authorized, but not required, to offer the same types of rates and contract options.

E. ENVIRONMENTAL IMPACT STATEMENTS

The new law directs the PSC to promulgate rules establishing requirements and procedures for the preparation of environmental impact statements regarding major actions of the PSC. The rules must establish standards for when an environmental impact statement is required, provide adequate time for members of the public to comment and be heard on environmental impact statements and establish time lines that permit thorough review of environmental issues and the processing of PSC dockets without undue delay in view of the need for additional transmission capacity.

F. INTERVENOR FINANCING

Under prior law, the PSC could compensate nonutility intervenors in cases before it for all or a portion of the intervenor's costs of intervening if certain conditions were met. The new law requires the PSC to compensate intervenors if the conditions are met (i.e., changes the authority to a duty). The new law changes one of the conditions under which compensation will be provided, specifying that compensation will be provided if an adequate presentation of a significant position would not occur, rather than not be possible, without the compensation. In addition, the new law increases the funding for intervenor compensation from $250,000 per year to $500,000 per year.

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APPENDIX

PUBLIC BENEFIT PROGRAMS FUNDING AND FEES

This appendix presents estimates of the levels of funding for public benefit programs that are required under the new law and the effects of the required fees and charges on customers' utility bills. It is a revision of the analysis contained in the June 23, 1999 Legislative Council Staff Memorandum to Interested Legislators, *Public Benefit Programs Funding and Fees in 1999 Assembly Bill 389 and 1999 Senate Bill 196 (the "Reliability 2000" Proposal).*

This appendix also describes the assumptions used in arriving at the estimates. In reviewing these estimates, it is also important to review the assumptions used since use of different assumptions could result in different estimates.

The estimates in this attachment are based on information previously presented to the Joint Legislative Council's Special Committee on Utility Public Benefit Programs (specifically, information contained in Memo No. 6, *Expenditures on Public Benefits in 1993, 1995 and 1997* (revised January 21, 1999), Memo No. 8, *Expenditures on Low-Income Programs* (April 15, 1999) and Memo No. 9, *Profile Data Regarding Certain Energy Providers* (April 15, 1999)) and new information regarding 1998 expenditures by public utilities on public benefit programs, provided by the PSC staff. These memoranda are available at the Internet address shown on the first page of this Information Memorandum. Where possible, utility data from 1998 is used, since this is the year that the new law uses as a benchmark; where 1998 data is not available, extrapolations are made from earlier years' data.

G. PROGRAM FUNDING

This section estimates the level of funding for public benefit programs that will result under the new law.

1. Low-Income Programs

The funding for the low-income programs is the sum of: (a) revenues that major investor-owned natural gas and electric utilities are required to collect, equal to those utilities' 1998 public benefits expenditures, as determined by the PSC; (b) revenues from new fees collected by electric utilities and retail electric cooperatives; and (c) federal revenues received by the state for low-income programs corresponding to the three funding sources.

a. Continued Major Utility Revenues Based on 1998 Expenditures

The best current estimate of 1998 expenditures of major investor-owned natural gas and electric utilities on low-income programs is $17.5 million. In addition, these utilities reported to the PSC $45.6 million in uncollectible bills in that year. It is estimated that about 1/2 of this amount, or $22.8 million, is attributable to low-income customers.[8] The total 1998 expenditures on low-income programs that utilities would be required to continue to collect for low-income

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8. According to staff at the PSC, Wisconsin Gas Company attributes between 50% and 60% of its uncollectibles to low-income customers. Since that utility has one of the highest numbers of low-income customers and since the proportion of other utilities' uncollectibles attributable to low-income households appears to be substantially lower, the PSC staff suggests that the low end of this range (50%) may serve as a rough estimate of the proportion of uncollectibles that may be attributed to low-income households statewide.

programs in fiscal year 1999-2000 and subsequent years is the sum of these amounts, or about $40.3 million, although the amount ultimately determined by the PSC may differ from this estimate.

b. Revenues From New Fees

The revenue from new fees for low-income programs in FY 1999-2000 is $24 million minus an amount that is in proportion to the length of time that has elapsed in that fiscal year before the DOA promulgates rules setting the amount of the fees for investor-owned utilities. For purposes of this analysis, it is assumed that the DOA will set these fees by emergency rule, and thereby start the collection of the fees, by January 1, 2000, half-way through the fiscal year. As a result, this analysis assumes that the revenues will be reduced by 1/2, raising $12 million.

The revenues from new fees for low-income programs in subsequent years will depend on the calculations described in Part V, C. of this Information Memorandum. This amount cannot be estimated with certainty at this time. If all of the factors in the formulae remain constant, the funding level will not change from one year to the next. For this analysis, it is assumed that economic conditions (affecting household income), fuel prices and weather patterns (affecting household energy consumption) will not change greatly in the initial years of the program. The remaining variable that is likely to change is the level of federal funding. Based on recent congressional action, this funding is expected to increase by $3.3 million between FY 1997-98 (the base funding year for federal funds) and FY 2000-01, reducing the amount that must be raised from the fees by an equal amount. Based on these assumptions, the revenues from new fees for low-income programs in FY 2000-01 will be set to raise approximately $20.7 million.

c. Federal Revenues

The federal revenues that Wisconsin receives for low-income public benefit programs depend on appropriations from the U.S. Congress. Wisconsin is expected to receive $43.3 million in FY 1999-2000 and approximately the same amount in FY 2000-01.

d. Table Summarizing Revenues

Table 1 summarizes the estimates of funding for low-income public benefit programs in FY 1999-2000 and FY 2000-01.

Table 1 -- Estimated Low-Income Programs Funding in Fiscal Years 1999-2000 and 2000-01*

	1999-2000	2000-01
Continued Charges	$40.3 million	$40.3 million
New Fees	$12.0 million	$20.7 million
Federal Revenues	$43.3 million	$43.3 million
TOTAL	$95.6 million	$104.3 million

*Estimates based on assumptions described in the text. In particular, the estimate of new fees in 2000-01 for low-income programs assumes no change in low-income need and a $3.3 million increase in federal revenues over FY 1997-98.

2. Energy Programs

The funding for the energy programs is the sum of: (a) revenues that major investor-owned natural gas and electric utilities are required to collect equal to those utilities' 1998 public benefits expenditures, as determined by the PSC; and (b) revenues from new fees collected by electric utilities and electric cooperatives. The continuing funding will be administered separately from the new fees in the first year of the program and combined with new fees in a state-administered program over the following two years.

a. Continued Major Utility Revenues Based on 1998 Expenditures

The best current estimate of 1998 expenditures of investor-owned electric and natural gas utilities on energy programs is $63.6 million. Thus, the amount these utilities would be required to continue to collect for energy programs in FY 1999-2000 would be $63.6 million, although, again, the amount ultimately determined by the PSC may differ from this estimate. The amount of continued revenues collected annually will be unchanged through FY 2003-04. In subsequent years, the fees will be reduced if the DOA determines to reduce the energy public benefit programs by an amount greater than the amount of the new fees for those programs.

b. Revenues From New Fees

The revenues from new fees for energy programs required by the proposal is $20 million. In FY 1999-2000, the fees will be reduced by about 1/2, reflecting the delayed start of the program. The amount of new fees for energy programs will be unchanged through FY 2003-04. In subsequent years, the fees will be reduced if the DOA determines to reduce or eliminate any of the energy public benefit programs. In addition, the revenues available for energy programs will be reduced by $2.5 million annually for 10 years if the NO_X provisions of the new law take effect, as described in Part VI, B. of the Information Memorandum.

c. Table Summarizing Revenues

Table 2 contains estimates of funding for energy programs in FY 1999-2000 and 2000-01.

Table 2 -- Estimated Energy Programs Funding in Fiscal Years 1999-2000 and 2000-01*

	1999-2000	2000-01
Continued Charges	$63.6 million	$63.6 million
New Fees	$10.0 million	$20.0 million
Federal Revenues	---	---
TOTAL	$73.6 million	$83.6 million

*Estimates based on assumptions described in the text.

H. EFFECTS OF REQUIRED CHARGES AND FEES ON CUSTOMERS' UTILITY BILLS

This section estimates the effects on the bills of utility customers of the charges and fees required by the new law. The effects will vary between types of energy providers. The customers of major investor-owned natural gas and electric utilities will pay the charges and fees shown in Tables 3 and 5. (These are the customers of Madison Gas & Electric Company, Northern States Power Company-Wisconsin, Superior Water, Light and Power Company, Wisconsin Electric, Wisconsin Fuel and Light Company, Wisconsin Gas Company, Wisconsin Power and Light Company and Wisconsin Public Service Corporation.) A person who receives natural gas service from a major utility but who receives electric service from a small investor-owned electric utility, a municipal electric utility or a retail electrical cooperative will pay the charges and fees in Tables 3 and 4. A customer of a retail electric cooperative who does not receive natural gas service will pay only the fees in Table 4. A customer of a small investor-owned electric utility who does not receive natural gas service will pay only the fees in Table 5.

The estimates presented here do not include the expenses that utilities incur in collecting the fees, which the new law authorizes the utilities to recover as part of the fees.

1. Continued Major Utility Revenues Based on 1998 Expenditures

As Tables 1 and 2 show, major investor-owned natural gas and electric utilities will be required to raise an estimated $40.3 million annually for low-income programs and $63.6 million annually for energy programs in the form of continued charges based on 1998 expenditures. The new law does not specify the manner of allocating these amounts among utility customer classes or types of utilities (electric or gas). As a result, this allocation will be determined by the PSC. In order to estimate the impact of these charges on individual ratepayers, some major assumptions have been made.

In 1997, the utilities allocated about 43% of the demand-side management portion of their energy programs to residential ratepayers. This analysis assumes a similar allocation for environmental protection and renewable resources programs. Under utility rate-making principles, all of the low-income program expenses are assumed to be allocated to residential ratepayers. It is likely that similar allocations will be used in the future.

The allocation of these charges between electric and gas utility customers is not presently known and is difficult to predict or characterize without a detailed analysis of the rate structures of each affected utility. Instead, for residential customers, this analysis attempts to provide a rough estimate of the impact of the fees on all ***households*** by assuming that the charges are imposed on residential electric customers only. Virtually all households are electric customers and somewhat over 1/2 of all households are also gas customers. By estimating the impact of the charges on electric customers only, this analysis underestimates the average charge that will be paid by households that are both electric and gas customers and overestimates the average charges that will be paid by households that are only electric customers.

For nonresidential customers, the analysis estimates the average rate impact on each electric or natural gas customer. It is assumed that each nonresidential customer has one service connection and is charged a separate fee for electric and natural gas service, if the customer has both types of service.

Based on these assumptions, the average amount included in the rates of customers for the continued funding can be estimated. These estimates are shown in Table 3. It should be emphasized that these estimates are of ***average*** impacts on rates and are only rough approximations based on major assumptions.

Table 3 -- Estimated Continued Charges Collected by Major Investor-Owned Natural Gas and Electric Utilities[1]

	Revenue Goal	*Number of Customers*	*Average Annual Rate Impact*
Residential Customers[2]			
Low-Income Programs	$40.3 million	1,806,000	$22.31
Energy Programs	$27.2 million	1,806,000	$15.06
TOTAL	$67.5 million	1,806,000	$37.38
Nonresidential Customers[3]			
Energy Programs	$36.4 million	366,000	$99.45
TOTAL	$36.4 million	366,000	$99.45

1. Estimates based on Tables 1 and 2 and assumptions described in the text.
2. Based on number of electric customers only; average rate impact is per household.
3. Based on number of electric and natural gas customers; average rate impact is per service connection.

2. New Fees

a. Municipal Utilities and Cooperatives

The new law requires municipal electric utilities and retail electric cooperatives to collect fees that average $16 per customer. With a total of about 437,000 customers, these entities will collect about $7 million in fee revenues. One-half of this amount ($3.5 million) will be applied to low-income programs and the other 1/2 to energy programs. In FY 1999-2000, these amounts will be reduced by about 1/2, reflecting the portion of the year that will have elapsed before the promulgation of the rules setting the amounts of fees that will be collected by investor-owned utilities. These fees are summarized in Table 4.

Table 4 -- Estimated New Fees Collected by Municipal Utilities and Retail Electric Cooperatives in Fiscal Years 1999-2000 and 2000-01*

	Revenue Goal		*Number of Customers*	*Average Annual Rate Impact*	
	1999-2000	2000-01		1999-2000	2000-01
Low-Income Programs	$1.75 million	$3.5 million	437,000	$4	$8
Energy Programs	$1.75 million	$3.5 million	437,000	$4	$8
TOTAL	$3.5 million	$7.0 million	437,000	$8	$16

*Estimates based on assumptions described in the text.

b. Investor-Owned Utilities

The new law requires all investor-owned electric utilities to collect fees that are calculated separately for low-income and energy programs. In the first year, the low-income component will be calculated to raise an amount equal to $24 million minus the amount collected by municipal utilities and cooperatives for low-income programs. Again, in FY 1999-2000, this amount will be reduced by about 1/2, reflecting the delayed start of the program. Thus, in FY

1999-2000, the fees will be set to collect 1/2 of $20.5 million, or $10.25 million. Seventy percent of this amount ($7.2 million) will be collected from residential customers and the balance ($3.1 million) will be collected from other customers.

In subsequent years, the low-income component of the new fees will depend on the calculations described in Part V, C. of the Information Memorandum. In the second year, it will be calculated to raise $20.7 million minus the amount collected by municipal utilities and cooperatives, or $17.2 million. Again, 70% of this amount ($12 million) will be collected from residential customers and the balance ($5.2 million) will be collected from other customers.

In each of the first five years, the energy component is calculated to raise an amount equal to $20 million minus the amount collected by municipal utilities and cooperatives for energy programs. Again, in FY 1999-2000, these amounts will be reduced by about 1/2, reflecting the delayed start of the program. Thus, the fees will be set to collect $8.25 million in FY 1999-2000 and $16.5 million in subsequent years. Seventy percent of this amount will be collected from residential customers and the balance from other customers. Beginning in FY 2004-05, if the DOA determines to reduce or discontinue any energy program elements, the fees will be reduced accordingly.

Estimates of the average amount of the fees are shown in Table 5.

Table 5 -- Estimated New Fees Collected by Investor-Owned Electric Utilities in Fiscal Years 1999-2000 and 2000-01*

	Revenue Goal		***Number of Customers***	***Average Annual Rate Impact***	
	1999-2000	2000-01		1999-2000	2000-01
Residential Customers					
Low-Income Programs	$7.2 million	$12.0 million	1,830,000	$4	$7
Energy Programs	$5.8 million	$11.6 million	1,830,000	$3	$6
TOTAL	$13.0 million	$23.6 million	1,830,000	$7	$13
Nonresidential Customers					
Low-Income Programs	$3.1 million	$5.2 million	231,000	$13	$23
Energy Programs	$2.5 million	$5.0 million	231,000	$11	$22
TOTAL	$5.6 million	$10.2 million	231,000	$24	$44

*Estimates based on Tables 1 and 2 and assumptions described in the text.

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