199—35.9 (476) Additional requirements for electric utilities. In addition to the requirements in rule 35.8(476), a plan for an electric utility shall include the following information:

35.9(1) *Load forecast.* Information specifying forecasted demand and energy use on a calendar year basis which shall include:

a. A statement, in numerical terms, of the utility's current 20-year forecasts including reserve margin for summer and winter peak demand and for annual energy requirements. The forecast shall not include the effects of the proposed programs in subrule 35.8(8), but shall include the effects to date of current ongoing utility energy efficiency programs.

b. The date and amount of the utility's highest peak demand within the past five years, stated on both an actual and weather-normalized basis. The utility shall include an explanation of the weather-normalization procedure.

c. A comparison of the forecasts made for each of the previous five years to the actual and weather-normalized demand in each of the previous five years.

d. An explanation of all significant methods and data used, as well as assumptions made, in the current 20-year forecast. The utility shall file all forecasts of variables used in its demand and energy forecasts and shall separately identify all sources of variables used, such as implicit price deflator, electricity prices by customer class, gross domestic product, sales by customer class, number of customers by class, fuel price forecasts for each fuel type, and other inputs.

e. A statement of the margins of error for each assumption or forecast.

f. An explanation of the results of sensitivity analyses performed, including a specific statement of the degree of sensitivity of estimated need for capacity to potential errors in assumptions, forecasts and data. The utility may present the results and an explanation of other methods of assessing forecast uncertainty.

35.9(2) *Class load data.* Load data for each class of customer that is served under a separate rate schedule or is identified as a separate customer class and accounts for 10 percent or more of the utility's demand in kilowatts at the time of the monthly system peak for every month in the year. If those figures are not available, the data shall be provided for each class of customer that accounts for 10 percent of the utility's electric sales in kilowatt hours for any month in the reporting period. The data shall be based on a sample metering of customers designed to achieve a statistically expected accuracy of plus or minus 10 percent at the 90 percent confidence level for loads during the yearly system peak hour(s). These data must appear in the 1992 and all subsequent filings, except as provided for in paragraph 35.9(2)*"c."*

a. The following information shall be provided for each month of the previous year:

(1) Total system class maximum demand (in kilowatts), number of customers in the class, and system class sales (in kilowatt-hours);

(2) Jurisdictional class contribution (in kilowatts) to the monthly maximum system coincident demand as allocated to jurisdiction;

(3) Total class contribution (in kilowatts) to the monthly maximum system coincident demand, if not previously reported;

(4) Total system class maximum demand (in kilowatts) allocated to jurisdiction, if not previously reported; and

(5) Hourly total system class loads for a typical weekday, a typical weekend day, the day of the class maximum demand, and the day of the system peak.

b. The company shall file an explanation, with all supporting work papers and source documents, as to how class maximum demand and class contribution to the maximum system coincident demand were allocated to jurisdiction.

c. The load data for each class of customer described above may be gathered by a multijurisdictional utility on a uniform integrated system basis rather than on a jurisdictional basis. Adjustments for substantive and unique jurisdictional characteristics, if any, may be proposed. The load data for each class of customer shall be collected continuously and filed annually, except for the period associated with necessary interruptions during any year to modify existing or implement new data collection methods. Data filed for the period of interruption shall be estimated. An explanation of the estimation technique shall be filed with the data. To the extent consistent with sound sampling and the required accuracy standards, an electric public utility is not required to annually change the customers being sampled.

35.9(3) *Existing capacity and firm commitments.* Information specifying the existing generating capacity and firm commitments to provide service. The utility shall include in its filing a copy of its most recent Load and Capability Report submitted to the Mid-continent Area Power Pool (MAPP).

a. For each generating unit owned or leased by the utility, in whole or in part, the plan shall include the following information:

(1) Both summer and winter net generating capability ratings as reported to the National Electric Reliability Council (NERC).

(2) The estimated remaining time before the unit will be retired or require life extension.

b. For each commitment to own or lease future generating firm capacity, the plan shall include the following information:

(1) The type of generating capacity.

(2) The anticipated in-service year of the capacity.

(3) The anticipated life of the generating capacity.

(4) Both summer and winter net generating capability ratings as reported to the NERC.

c. For each capacity purchase commitment which is for a period of six months or longer the plan shall include the following information:

(1) The entity with whom commitments have been made and the time periods for each commitment.

(2) The capacity levels in each year for the commitment.

d. For each capacity sale commitment which is for a period of six months or longer the following information:

(1) The entity with whom a commitment has been made and the time periods for the commitment.

(2) The capacity levels in each year.

(3) The capacity payments to be received per kW per year in each year.

(4) The energy payments to be received per kWh per year.

(5) Any other payments the utility receives in each year.

35.9(4) *Capacity surpluses and shortfalls.* Information identifying projected capacity surpluses and shortfalls over the 20-year planning horizon which shall include:

a. A numerical and graphical representation of the utility's 20-year planning horizon comparing forecasted demand in each year from subrule 35.9(1) to committed capacity in each year from paragraphs 35.9(3)*"a"* to 35.9(3)*"d."* Forecasted peak demand shall include reserve requirements.

b. For each year of the 20-year planning horizon, the plan shall list in MW the amount that committed capacity either exceeds or falls below the forecasted demand.

35.9(5) *Capacity outside the utility's system.* Information about capacity outside of the utility's system that could meet its future needs including, but not limited to, cogeneration and independent power producers, expected to be available to the utility during each of the 20 years in the planning horizon. The utility shall include in its filing a copy of its most recent Load and Capability Report submitted to the Mid-continent Area Power Pool (MAPP).

35.9(6) *Future supply options and costs.* Information about the new supply options and their costs identified by the utility as the most effective means of satisfying all projected capacity shortfalls in the 20-year planning horizon in subrule 35.9(4) which shall include:

a. The following information which describes each future supply option as applicable:

(1) The anticipated year the supply option would be needed.

(2) The anticipated type of supply option, by fuel.

(3) The anticipated net capacity of the supply option.

b. The utility shall use the actual capacity cost of any capacity purchase identified in paragraph 35.9(6)*"a"* and shall provide the anticipated annual cost per net kW per year.

c. The utility shall use the installed cost of a combustion turbine as a proxy for the capacity cost of any power plant identified in paragraph 35.9(6)*"a."* For the first power plant option specified in paragraph 35.9(6)*"a,"* the following information shall be provided:

(1) The anticipated life.

(2) The anticipated total capital costs per net kW, including AFUDC if applicable.

(3) The anticipated revenue requirement of the capital costs per net kW per year.

(4) The anticipated revenue requirement of the annual fixed operations and maintenance costs, including property taxes, per net kW for each year of the planning horizon.

(5) The anticipated net present value of the revenue requirements per net kW.

(6) The anticipated revenue requirement per net kW per year calculated by utilization of an economic carrying charge.

(7) The after tax discount rate used to calculate the revenue requirement per net kW per year over the life of the supply option.

(8) Adjustment rates (for example, inflation or escalation rates) used to derive each future cost in paragraph 35.9(6)*"c."*

d. The capacity costs of the new supply options allocated to costing periods. The utility shall describe its method of allocating capacity costs to costing periods. The utility shall specify the hours, days, and weeks which constitute its costing periods. For each supply option identified in paragraph 35.9(6)*"a,"* the plan shall include:

(1) The anticipated annual cost per net kW per year of capacity purchases from subparagraph 35.9(6)*"b"*(6) allocated to each costing period if it is the highest cost supply option in that year.

(2) The anticipated total revenue requirement per net kW per year from subparagraph 35.9(6)*"c"*(6) allocated to each costing period if it is the highest cost supply option in that year.

35.9(7) *Avoided capacity and energy costs.* Avoided capacity costs shall be based on the future supply option with the highest value for each year in the 20-year planning horizon identified in subrule 35.9(6). Avoided energy costs shall be based on the marginal costs of the utility's generating units or purchases. The utility shall use the same costing periods identified in 35.9(6)*"b"* when calculating avoided capacity and energy costs. A party may submit, and the board shall consider, alternative avoided capacity and energy costs derived by an alternative method. A party submitting alternative avoided costs shall also submit an explanation of the alternative method.

a. *Avoided capacity costs.* Calculations of avoided capacity costs in each costing period shall be based on the following formula:

AVOIDED CAPACITY COST = C x (1 + RM) x (1 + DLF) x (1 + EF)

C (capacity) is the greater of NC or RC.

NC (new capacity) is the value of future capacity purchase costs or future capacity costs expressed in dollars per net kW per year of the utility's new supply options from paragraphs 35.9(6)*"b"* and *"c"* in each costing period.

RC (resalable capacity) is the value of existing capacity expressed in dollars per net kW per year that could be sold to other parties in each costing period.

RM (reserve margin) is the generation reserve margin criterion adopted by the utility.

DLF (demand loss factor) is the system demand loss factor, expressed as a fraction of the net power generated, purchased, or interchanged in each costing period. For example, the peak system demand loss factor would be equal to peak system power loss (MW) divided by the net system peak load (MW) for each costing period.

EF (externality factor) is a 10 percent factor applied to avoided capacity costs in each costing period to account for societal costs of supplying energy. In addition, the utility may propose a different externality factor, but must document its accuracy.

b. Avoided energy costs. Calculations of avoided energy costs in each costing period shall be based on the following formula:

AVOIDED ENERGY COSTS = MEC x (1 + ELF) x (1 + EF)

MEC (marginal energy cost) is the marginal energy cost expressed in dollars per kWh, inclusive of variable operations and maintenance costs, for electricity in each costing period.

ELF (system energy loss factor) is the system energy loss factor, expressed as a fraction of net energy generated, purchased, or interchanged in each costing period.

EF (externality factor) is a 10 percent factor applied to avoided energy costs in each costing period to account for societal costs of supplying energy. In addition, the utility may propose a different externality factor, but must submit documentation of its accuracy.