FILED WITH
Executive Secretary
February 01, 2013
IOWA UTILITIES BOARD

STATE OF IOWA

BEFORE THE IOWA UTILITIES BOARD

IN RE:	:	
MIDAMERICAN ENERGY COMPANY	:	**Docket No. EEP-2012-0002**

DIRECT TESTIMONY
OF
O. DALE STEVENS, II

Q. Please state your name and business address.

A. O. Dale Stevens, II. MidAmerican Energy Company (MidAmerican), 4299 Northwest Urbandale Drive, Urbandale, Iowa 50322.

Q. By whom are you employed and in what capacity?

A. I am employed by MidAmerican as Manager, Market Assessment.

Q. Please describe your responsibilities as Manager, Market Assessment.

A. I am responsible for overseeing the electric and natural gas market price forecasts, electric transmission support for the generation and trading groups and the development of long-term electric capacity plans**.**

Q. Please describe your education and business experience.

A. I graduated from the University of Missouri at Rolla with a Bachelor of Science degree in Electrical Engineering in 1972. I have been employed by MidAmerican or its predecessors in a variety of planning and managerial positions. I joined Iowa Power and Light Company, a predecessor of the

Company, in 1972 as a Scheduler. During my career with the Company and its predecessors, I have worked in system planning (1974-1980), operational planning (1980-1986), rates (1986-1995) and market assessment (1995-present). In 1991, I was promoted to manager of the electric rate department for Midwest Power Systems Inc., a predecessor of MidAmerican and in 1995, I assumed my current role as Manager, Market Assessment.

Q. Have you testified before Iowa Utilities Board or other regulatory bodies previously?

A. Yes. I testified before the Iowa Utilities Board (Board) in Docket Nos. GCU-88-1, EEP-91-3, EEP-08-2, RPU-91-6, RPU-92-2, ECR-93-2, RPU-94-4, ECR-94-1, AEP-95-2, AEP-95-4, AEP-95-5, EEP-95-3, GCU-01-1, RPU-01-9, RPU-02-10, RPU-03-1, RPU-04-3, RPU-05-4, RPU-07-2, RPU-08-2, RPU-08-4 and RPU-09-3. In addition, I have presented testimony before the Federal Energy Regulatory Commission in ER90-480-000 and the Illinois Commerce Commission in Docket No. 99-0196.

Q. What is the purpose of your direct testimony?

A. The purpose of my testimony is to sponsor information about the Plan required under the following Iowa Utilities Board (Board) rules:

- 35.9 (1) Electric Load Forecast
- 35.9(3) Existing Electric Capacity and Firm Commitments
- 35.9(4) Electric Capacity Surpluses and Shortfalls
- 35.9(5) Electric Capacity Outside the Utility's System
- 35.9(6) Future Electric Supply Options and Costs

- 35.9(7) Electric Avoided Capacity and Energy Costs

Q. Does your testimony meet these filing requirements?

A. Yes, I have provided responses to each of the above filing requests in my testimony and exhibits.

Q. Are you sponsoring any exhibits in the filing?

A. Yes. I am sponsoring Exhibit___(ODS-1), which includes the following schedules:

- Schedule 1a: Summer and Winter Peak Demand, Reserve and Capacity Requirements
- Schedule 1b: Dependent and Independent Variables Used for Peak Demand Forecast
- Schedule 1c: Dependent and Independent Variables used for Customer and Energy Forecasts
- Schedule 1d: 2012 Peak Demand Forecast
- Schedule 1e: 2012 Energy Forecast
- Schedule 2: Seasonal Capacity Ratings and Unit Lives
- Schedule 3: Future Committed Generation Capacity Information
- Schedule 4: Capacity Purchase Commitments
- Confidential Schedule 5: Capacity Sales Commitments
- Schedule 6: Summer Load and Capability
- Schedule 7: Capacity Surplus and Deficit – Summer Season
- Schedule 8: Power Plant Announcements for the Midwest
- Schedule 9a: Preliminary Expansion Plan – Alternative 1

- Schedule 9b: Preliminary Expansion Plan – Alternative 2
- Schedule 10: Avoided Capacity Costs – Peaker Method
- Schedule 11: Avoided Capacity Costs Summary
- Confidential Schedule 12: Annual Average Avoided Energy Costs

Q. What filing requirements contained in 199 Iowa Administrative Code 35.9(1), does your testimony address?

A. My testimony addresses electric load forecasts. MidAmerican files both demand and energy forecasts[1] for a 20-year period annually as required in 199 Iowa Administrative Code (IAC) 35.9(1). The most recent filing occurred in May 2012.

Q. Are you providing a statement, in numerical terms, of the utility's current 20-year forecasts, pursuant to 199 Iowa Administrative Code 35.9(1)"a"?

A. Yes. 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 is provided in Exhibit___(ODS-1), Schedule 1a.

Q. What are the date and amount of MidAmerican's highest peak demand within the past five years, stated on both an actual and weather-normalized basis, as required to be reported pursuant to 199 Iowa Administrative Code 35.9(1)"b"?

A. The highest actual measured peak load within the past five years was 4,752 MW, with the corresponding weather-normalized peak load of 4,438 MW. The highest peak demand within the past five years occurred on July 19, 2011. The

[1] The Demand and Energy Forecast in Exhibit___(ODS-1), Schedule 1 was the most recently approved forecast at the time MidAmerican commenced development of its plan.

residential direct load control program was in effect at the time of peak. After removing the effects of energy efficiency programs, the gross peak load on that day would have been 4,507 MW.

Q. Please explain the procedure used to calculate weather-normalized peak load.

A. Historical weather-normalized peak load was calculated to remove the weather impact from the historical values used in the forecast model. The normal values for temperature-humidity index (THI) and three-day build up were defined as the averages for both of those weather measures from 1980 through 2011. The gross peak value was re-calculated using average or "normal" weather results. The peak re-calculation was performed as follows: In the historical time period, the normal weather values were substituted for actual weather values. The model re-calculated the historical peak values using the normal weather values. The difference between the actual and weather-normalized peaks in a given year was the sum of: (normal weather value – actual weather value) * (model coefficient for that weather variable) for the THI, dry-bulb temperature and three-day build up variables. An explanatory variable consisting of the cumulative MW of energy efficiency impacts was included in the forecast model to ensure that the weather normalized peak reflected the actual level of historical energy conservation savings.

Q. Did you provide 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, pursuant to 199 Iowa Administrative Code 35.9(1)"c"?

A. Yes. 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 is provided in Exhibit___(ODS-1), Schedule 1d. The actual and weather-normalized system load peaks for the years 2006-2011 are as follows:

	Actual Gross Peak Demand	Weather-Normalized Gross Peak Demand
• 2006:	4,544 MW	4,336 MW
• 2007:	4,295 MW	4,422 MW
• 2008:	4,263 MW	4,423 MW
• 2009:	4,354 MW	4,428 MW
• 2010:	4,517 MW	4,467 MW
• 2011	4,821 MW	4,507 MW

The actual load figures do not include the impacts of the energy efficiency or demand response programs. The weather-normalized values were calculated as described above.

Q. Please explain all significant methods and data used, as well as assumptions made, in the current 20-year forecast, as required by 199 Iowa Administrative Code 35.9(1)"d".

A. The forecast was developed using multiple regression analysis in MetrixND, version 4.4.1, developed by Itron, Inc. The model assumed an additive equation in the form of:

$$y = r + \alpha X + \beta Y + \gamma Z$$

where, X, Y and Z are the variables, α, β and γ are the coefficients and r is the constant.

Evaluation of the forecast model focused on the maximization of "adjusted" R^2, which is a measure of model accuracy, and the minimization of time mean value of absolute percentage errors (MAPE) for the time period used to develop the model. The R^2 is a measure of the total variation explained by the regression. It ranges between 1 and 0, with a 1 indicating that 100 percent of the variation has been explained. MAPE defines the magnitude of errors in the model. The lower the MAPE number, the better the model is considered to be. The Durbin-Watson (DW) statistic, which measures the presence/absence of first-order autocorrelation between the variables, was also monitored, although it was not the prime consideration in determining the forecast quality. DW varies between 0 and 4; when DW=2, the model is considered to be free of first-order autocorrelation.

The values of dependent and independent variables for the peak demand forecast are tabulated in Exhibit___(ODS-1), Schedule 1b, while those for energy and customer forecasts are provided in Exhibit___(ODS-1), Schedule 1c.

Q. Please describe the forecast modeling and variables used to calculate the peak demand forecast.

A. The forecast was based on summer peak load. The peak demand values, which are not adjusted for the impact of the energy efficiency programs, were +calculated according to the following equation:

Gross Peak Demand =Native Peak Demand + Vacations + Summer Saver + Curtailments

The 2012 peak load demand forecast was developed using six independent variables. These variables are:

1) Real non-agricultural gross state product for the state of Iowa

2) Average real price per kWh for MidAmerican Energy Company's (MidAmerican) residential customers from July through September, lagged one year

3) Temperature-humidity Index, load-weighted for MidAmerican's service territory

4) Three-day-buildup, load-weighted for MidAmerican's service territory

5) Three-day-build-up, load-weighted for MidAmerican's service territory, multiplied by a time trend to show changes over time

6) Cumulative conservation MW for MidAmerican Energy

For each year, the nominal price for residential customers was determined by dividing historical revenue from July through September by the corresponding usage (kWh) from July through September. The gross state product and gross domestic product deflator, used to convert the nominal price to real price, were obtained from IHS Global Insight Inc., which provides demographic and economic data. MidAmerican has recently implemented adjustment clauses to recover certain costs associated with emission-control projects and coal-related costs that exceed the level currently reflected in base rates. This results in electric rate increases of $38.7 million and $76 million in

2012 and 2013, respectively. To forecast the price beyond this point, the real price of residential electricity was escalated by the growth projection for the real price of retail residential electricity of the Energy Information Administration (EIA) at the U.S. Department of Energy. Beginning in 2014, EIA forecasts the real price of retail residential electricity in the United States to decrease by 0.04% percent annually. Since the Illinois and South Dakota customer demand is a relatively small percentage of the overall MidAmerican demand, only the Iowa real non-agriculture gross state product data was used. Also, the areas served by MidAmerican in these states are adjacent to Iowa and thus, the Iowa data was assumed to be representative for these service areas.

Temperature data used for the weather variables was obtained from the National Weather Service. Dew point data was obtained from Freese-Notis, MidAmerican's weather forecast vendor. This data was obtained for five weather stations: Des Moines, Sioux City, Waterloo, Moline and Omaha. The historical temperature-humidity index (THI) values were obtained for each station at the time of system peak load. The aggregate THI was calculated according to the following equation, weighted using the estimated relative demand at the time of peak for the five different stations:

$$THI = 0.4\ (\text{dry-bulb thermometer temperature } F + \text{wet-bulb thermometer temperature } F) + 15$$

The three-day build-up weather variable was calculated by taking the average daily temperature for the three days prior to each peak according to the following equation:

$$3DayAverageTotal_t = AverageTemp_{(t-1)} + AverageTemp_{(t-2)} + AverageTemp_{(t-3)}$$

Similar to THI, the three-day build-up calculations also took into account the demand weights associated with the weather stations. The historical dry-bulb temperature values at the time of system peak load were obtained for each station. The dry-bulb temperature calculations also took into account the demand weights associated with the weather stations.

Normal weather data was used to forecast future peak values. To differentiate weather conditions and determine the sensitivity of demand to alternative weather conditions, hot and extreme cases were defined. In general, weather variables such as temperature are known to be normally distributed. The definitions for the hot and extreme weather cases are as follows:

- <u>Normal (average)</u>
  - Boundary limit: From 0-Standard deviation to + Infinity
- <u>Hot</u>: Defined as 1.0 Standard deviation from normal for both weather variables
  - Boundary limit: From 1-Standard deviation to + Infinity
- <u>Extreme</u>**:** Defined as 1.6 Standard deviation from normal for both weather variables
  - Boundary limit: From 1.6-Standard deviation to + Infinity

To determine the impact of different weather scenarios, forecast values were calculated for the hot and extreme weather conditions, in addition to normal weather. These values are presented along with those corresponding to normal weather in Exhibit___(ODS-1), Schedule 1d. An explanatory variable containing MidAmerican's cumulative conservation MW was included in the

forecast model. Both historical and forecast values for this variable were obtained from MidAmerican's energy efficiency group.

The current forecast reflects good statistical parameters with an adjusted R^2 of 0.983 and a mean absolute percentage error (MAPE) of 1.56 percent, and all six variables were found to be statistically significant at the 10 percent level.

Q. What methodology did you use to calculate customer and sales forecasts?

A. The customer and sales forecasts were produced on a monthly basis and carried out in two steps as follows:

- Step 1: The aggregate numbers were forecasted directly by revenue class:
  - Residential,
  - Commercial,
  - Industrial, and
  - Public authority.

  For street lighting, the current customer numbers were assumed to remain constant. MidAmerican customers in the Iowa service territory were modeled using with state of Iowa data or appropriate county level data, MidAmerican customers in the Illinois service territory were modeled using economic and demographic drivers from the Quad Cities metropolitan statistical area (MSA) and MidAmerican customers in the South Dakota service territory were modeled using appropriate county level data when possible.
- Step 2: The usage per customer (UPC) values were forecasted for the residential, commercial and public authority classes. The UPC values were then multiplied by the customer forecast for the appropriate revenue class to

arrive at the electric sales forecast. For the industrial class, electric sales were forecasted directly. The electric sales forecast for the street lighting class was forecasted directly using a trend.

Q. Please describe the forecast modeling and variables used to calculate customer and sales forecasts.

A. The historic data includes numerous step changes and other anomalies due in part to mergers, changes in billing systems and customer class definitions at MidAmerican and the migration of customers between different classes. Because most of these changes occurred prior to 2000, the historical period upon which all models were based begins in January 2000 to avoid missing and questionable data.

Economic and demographic data for the models were based on forecasts from IHS Global Insight Inc. Other data, such as customer numbers, price, sales, revenue class, jurisdiction, etc. were taken from internal sources. Average electricity prices for a given class were calculated by dividing the class revenue by the corresponding usage (kWh). To evaluate the reasonableness of the model, the emphasis was put on three factors:

- Selection of variables which were likely to be key drivers,
- Presence of agreement between the historical and forecast growth numbers, and
- Statistical significance in independent variables.

Other considerations were the sign (the direction of change) and impact (the magnitude of elasticity coefficients) of variables on the forecasted

dependent variables. The variables used to forecast customers for the various revenue classes are:

- **Residential:** Non-farm employment, population, monthly binary variables, binary variable for 2008 flooding and autoregressive moving average (ARMA) errors,
- **Commercial:** Number of households, monthly binary variables and ARMA errors,
- **Industrials:** Time trend, monthly binary variables and ARMA errors, and
- **Public Authority:** State and local government employment, monthly binary variables and ARMA errors.

The UPC and electric sales forecasts considered monthly billing days, weather and monthly binaries to be key drivers or indicators, in addition to economic and demographic variables. Cooling and heating degree day data was obtained from the National Weather Service and was based on a baseline of 65 degrees Fahrenheit. The values for weather variables were calculated using a weighted average of readings from five weather stations: Moline, Waterloo, Des Moines, Sioux City and Omaha.

The UPC and electric sales forecasts were based on historical data that represents billed sales. This means that the sales numbers reflect in part the weather conditions from the previous month as well as the weather conditions for the current month, depending on the meter read date. To take this into account, the cooling and heating degree days for both the current and prior month were considered as independent variables. The forecasts used actual

weather values for the historical period and normal weather values for the forecast period, determined from a regression analysis that took into account the recent decline in heating degree days, for the forecast period. The 2012 sales forecast results and other related data are shown in Exhibit___(ODS-1), Schedule 1e.

The sales variables used for the different revenue classes are:

- **Residential UPC:** State and local government employment, heating degree days (current and lagged), heating degree day trend, cooling degree days (current and lagged), hours of light, monthly billing days, real residential price (lagged twelve months), monthly binaries and ARMA errors,
- **Commercial UPC:** Non-farm employment, monthly billing days, heating degree days (current and lagged), heating degree day trend, cooling degree days (current and lagged), heating degree day trend, time trend, monthly binaries and ARMA errors,
- **Industrials UPC:** Real gross state product, non-farm employment, monthly billing days, real industrial price, monthly binaries and ARMA errors, and
- **Public Authority UPC:** State and local government real gross state product, heating degree days (lagged), heating degree trend, cooling degree days (lagged), monthly billing days, hours of light, monthly binaries and ARMA errors.

The heating degree trend variable measures the changing relationship between heating degree days and electric kWh sales. Heating degree days stay constant in the forecast period.

Q. Please describe the statistics used to develop forecasts.

A. The residual patterns and model fit statistics were studied during modeling. The residuals indicate the difference between the predicted and actual values and any pattern associated with residuals suggests a missing variable(s) which may account for seasonality. These residuals were studied through the autocorrelation factor and partial autocorrelation diagrams in MetrixND. Serial correlation was determined to be an issue in certain cases. This was addressed using monthly binary variables and, when necessary, autoregressive (AR) and moving average (MA) corrections. Tables 1 and 2 show the adjusted R^2 and MAPE values, and the listing of other model statistics for the customer forecasts, respectively.

Table 1: Customer Forecasts

Revenue Class	Adjusted R^2	MAPE
Residential	1.000	0.02%
Commercial	0.999	0.04%
Industrial	0.997	0.26%
Public Authority	0.998	.018%

Table 2: Customer Forecasts

	Residential	Commercial	Industrial	Public Authority
Adjusted Observations	123	99	111	147
Deg. of Freedom for Error	107	85	97	133
R-Squared	1	0.999	0.997	0.998
Adjusted R-Squared	1	0.999	0.997	0.998
AIC	10.51	7.86	3.35	7.2
BIC	10.88	8.22	3.69	7.48
F-Statistic	60,909.476	5,731.416	2,732.024	4,796.964
Prob (F-Statistic)	0	0	0	0
Log-Likelihood	-805.02	-515.31	-329.47	-723.56
Model Sum of Squares	29,761,920,211	168,692,332.3	900,777.33	76,081,100.91
Sum of Squared Errors	3,485,528.23	192,446.03	2,460.15	162,262.66
Mean Squared Error	32,575.03	2,264.07	25.36	1,220.02
Std. Error of Regression	180.49	47.58	5.04	34.93
Mean Abs. Dev. (MAD)	130.4	34.4	3.54	23.37
Mean Abs. % Err. (MAPE)	0.02%	0.04%	0.26%	0.18%
Durbin-Watson Statistic	1.869	1.868	2.062	1.723
Ljung-box statistic	42.73	28.53	34.48	21.62
Prob (Ljung-Box)	0.0107	0.2385	0.0765	0.6022

Tables 3 and 4 show the adjusted R^2 and MAPE values, and the listing of model statistics associated with the sales forecasts, respectively.

Table 3: UPC (residential, commercial and public authority) and Electric Sales (industrial) Forecasts

Revenue Class	Adjusted R^2	MAPE
Residential	0.967	3.23%
Commercial	0.879	2.76%
Public Authority	0.804	3.36%
Industrial	0.721	4.81%

Table 4: Sales Forecasts

	Residential	Commercial	Industrial	Public Authority
Adjusted Observations	136	76	136	76
Deg. of Freedom for Error	118	57	119	59
R-Squared	0.971	0.908	0.754	0.846
Adjusted R-Squared	0.967	0.879	0.721	0.804
AIC	7.08	10.39	21.2	12.238
BIC	7.47	10.97	21.57	12.759
F-Statistic	230.578	31.26	22.83	20.232
Prob (F-Statistic)	0	0	0	0
Log-Likelihood	-656.61	-483.55	-1,617.80	-555.87
Model Sum of Squares	4,130,724.87	14,762,309.6	525,416,268,900	55,026,009
Sum of Squared Errors	124,348.83	1,495,450.52	171,170,186,531	10,029,187
Mean Squared Error	1,053.80	26,235.97	1,438,404,928.84	169,986
Std. Error of Regression	32.46	161.98	37,926.31	412.29
Mean Abs. Dev. (MAD)	24.89	114.82	28,120.24	299.65
Mean Abs. % Err. (MAPE)	3.23%	2.76%	4.81%	3.36%
Durbin-Watson Statistic	2.094	2.114	2.079	2.055
Ljung-Box Statistic	43.98	69.75	40.95	58.76
Prob (Ljung-Box)	0.0077	0.0000	0.0169	0.0001

The comparison of tables clearly indicates that better statistics were obtained for the customer models than for the UPC and electric sales models. The reason is that there is more uncertainty in the sales forecasts due to the presence of multiple drivers and their possible interactions. For example, deviations from the usual historical pattern of usage for specific large industrial customers (such as a change in the company production schedule) or a change in billing cycles could lead to large fluctuations in the billed sales.

Q. How did you adjust for energy efficiency impacts resulting from MidAmerican's demand side management programs?

A. Energy efficiency conservation impacts as promoted through company demand-side management programs were specifically adjusted in these forecasts to better align with recent and forecasted levels. Historically, the regression

models have incorporated impacts of energy efficiency program MW savings since 1990 in the peak demand forecast and MWh savings by class since 2000 in the electric sales forecasts.

In MidAmerican's current five-year energy efficiency plan, MidAmerican proposed significantly higher performance goals than in previous plans, with a savings of 1.5 percent of total retail electric MWh sales expected by 2010. A separate adjustment to reflect the increased energy savings goals was included in the forecast. The regression models were able to capture some, but not all of the increased energy efficiency efforts.

Q. Did you provide a statement of the margins of error for each assumption or forecast, pursuant to 199 Iowa Administrative Code 35.9(1)"e"?

A. Yes. For all forecasts, the calculation of errors is explained and listed by forecast parameters in response to section 35.9(1)"d," above.

Q. What were the results of the sensitivity analysis performed on peak load and sales forecasts, pursuant to 199 Iowa Administrative Code 35.9(1)"f"?

A. The peak load and sales forecasts were bounded by the corresponding 95 percent upper and 95 percent lower confidence limits. The current forecasts also were compared to the prior five peak demand and sales forecasts from 2006 to 2011, as shown in Exhibit___(ODS-1), Schedule 1d and Exhibit___(ODS-1) Schedule 1e.

Q. Did you include the most recent Load and Capability Report submitted to the Mid-continent Area Power Pool (MAPP) as required by 199 Iowa Administrative Code 35.9(3)?

A. No. The Mid-continent Area Power Pool no longer exists. As described below, MidAmerican is providing all of the other information required by 199 Iowa Administrative Code 35.9(3).

Q. Did you prepare information on MidAmerican's generating capability, pursuant to 199 Iowa Administrative Code 35.9(3)"a"?

A. Yes. Seasonal plant capabilities and the remaining lives for MidAmerican's existing owned generation is summarized in Exhibit___(ODS-1), Schedule 2.

Q. Please describe MidAmerican's future generating firm capacity.

A. Exhibit___(ODS-1), Schedule 3 contains MidAmerican's forecasted commitments for future generating firm capacity including the type, anticipated in-service year, anticipated life and the summer and winter capability ratings.

Q. Have you provided information on MidAmerican's future capacity purchase commitments as required by 199 Iowa Administrative Code 35.9(3)"c"?

A. Yes. Committed capacity purchase information including the entity with whom the commitment was made, the time periods for the commitment and the capacity level are provided in Exhibit___(ODS-1), Schedule 4.

Q. Have you provided MidAmerican's future capacity sale commitments as required by 199 Iowa Administrative Code 35.9(3)"d"?

A. Yes. Committed capacity sales information is provided in Exhibit___(ODS-1), Confidential Schedule 5, including the entity with whom the commitment was made, the time periods for the commitment, the capacity levels, the capacity payments, the energy payments and other payment information.

Q. Please describe how you have identified projected capacity surpluses and shortfalls over the 20-year planning horizon, pursuant to 199 Iowa Administrative Code 35.9(4).

A. The capacity surpluses and shortfalls are presented numerically in Exhibit___(ODS-1), Schedule 6 and graphically in Exhibit___(ODS-1), Schedule 7, which compare MidAmerican's forecasted demand obligations[2] to its committed capacity. Additionally, the load and capability table provided on page 2 of Exhibit___(ODS-1), Schedule 6 summarizes the information provided in Exhibit___(ODS-1), Schedules 1 – 5. This table compares the Company's load requirements, including planning reserves, to its supply capability, which includes owned capacity and net purchases and sales. The difference between the annual capability and the load requirement is the capacity surplus or shortfall for that year. The existing energy efficiency programs and demand side management impacts are reflected in the summary. Incremental energy efficiency programs and demand side management impacts associated with this energy efficiency filing are not included in the summary.

The process used to determine capacity surpluses and shortfalls for this energy efficiency plan is consistent with MidAmerican's internal capacity planning methodology. MidAmerican's criteria for capacity planning focus on meeting customer peak load plus the Midwest Independent Transmission System Operator's (Midwest ISO) planning reserve margin, a minimum requirement established to provide reliable power to the Midwest region of the

[2] The load forecast obligation is the net peak demand forecast adjusted for the existing demand side management programs increased by MISO's planning reserve margin, currently 11.3 percent to reflect the planning reserve requirement.

United States, including MidAmerican's service territory. The Midwest ISO conducts an annual assessment of its region using a loss of load expectation (LOLE) study to determine the reserve margin for the upcoming planning year. Each load serving entity, including MidAmerican, is responsible for meeting load uncertainties associated with weather, forecasting and demand side management. MidAmerican currently plans for capacity additions, purchased or owned, to meet its demand obligations plus the Midwest ISO planning reserve margin assuming the normal weather forecast.

MidAmerican forecasts a capacity deficiency beginning in 2016 prior to the implementation of a resource expansion plan.

Q. Please describe MidAmerican's plan for meeting its future needs with capacity outside of the utility's system as required by 199 Iowa Administrative Code 35.9(5).

A. The announced capacity additions and plant retirements within the Midwest provide an indicator of the availability of capacity outside MidAmerican's system. Announcements of capacity additions include traditional central power station plants (simple-cycle combustion turbines, and combined-cycle combustion turbines), renewable generation (wind, wood and biomass) and unit upgrades (nuclear). Other future capacity may be under consideration, such as upgrades to existing plants or projects under development by utilities that have not been publicly announced. However, a number of retirements, especially

coal-fired plants, have been announced. A list of proposed new capacity[3] along with announced capacity retirements in the Midwest ISO as of December 31, 2012, is provided in Exhibit___ (ODS-1), Schedule 8.

Additionally, for its Illinois load, MidAmerican is considering using the Illinois Power Agency (IPA) to secure power for its Illinois customers as one option to meet its future needs for its Illinois load. MidAmerican's Illinois load obligation is about 400 MW.

Regardless of the capacity available, adequate transmission must exist to deliver the output of these plants to MidAmerican's load for the capacity to be a viable resource. Deliverability must be evaluated for each resource individually, recognizing conditions such as load growth, other capacity additions or retirements and transmission additions and constraints.

Q. Please describe future supply options that MidAmerican will use to satisfy its projected capacity shortfalls in the 20-year planning horizon as required by 199 Iowa Administrative Code 35.9(6)"a".

A. For purposes of calculating avoided costs, MidAmerican assumed that capacity and energy would be purchased from the market to meet any shortfalls identified in Exhibit___(ODS-1), Schedule 6. The avoided energy costs in the near term are driven by avoiding the operation of MidAmerican-owned generation. As load growth occurs, the avoided energy cost increasingly avoids a purchase from the market. This occurs over an extended time period and may

[3] Some of the projects announced are never developed due to such issues as financing difficulties, the inability to find a buyer for the energy, transmission access limitations, environmental restrictions and public opposition.

provide a higher avoided energy cost than would have been experienced based on an expansion plan.

The current status of MidAmerican's resource planning is summarized in Exhibit ___(ODS-1), Schedule 9a and Exhibit ___(ODS-1), Schedule 9b where two possible alternative resource plans are presented. Capacity plans are fluid at this time, and may differ substantially from either of the plans shown in the table due to the uncertainties that exist concerning federal environmental legislation, natural gas and other fuel price forecasts, a carbon tax, the state's desire to reduce its carbon footprint, construction costs, development of new technologies, changes in planning reserve requirements and many other factors. MidAmerican's current approach is to continue to take advantage of economic opportunities including a further addition of wind power in Iowa. This will occur when reasonably-priced turbines and equipment can be acquired, a good wind site can be developed in a time frame that allows the project to receive production tax credits, and projected revenues arising from the wind generation are anticipated to cover the costs of the new generation over the life of the project.

Wind power is primarily an energy resource with small capacity benefit (about a 10-15 percent capacity benefit). It does not change long-term capacity requirements to any great extent in a capacity planning sense. Based on MidAmerican's projected capacity deficiency for the resource plan summarized in Exhibit ___(ODS-1), Schedule 9a, new capacity will be needed to meet the projected demand and planning reserve margin beginning in the 2023 time

period. The incremental peak load reductions from the new energy efficiency plan will change this assumption. For the period beyond 2024 any remaining requirements will be met through offsets from incremental energy efficiency and purchases from the market. MidAmerican will modify its resource expansion plan as new information and opportunities become available.

Q. Please provide the actual capacity cost and the anticipated annual cost per net kW per year for planned capacity purchases as required by 199 Iowa Administrative Code 35.9(6)"b".

A. MidAmerican calculated long-term avoided costs are based on capacity purchases commencing in 2023, as outlined in Exhibit___(ODS-1), Schedule 9a. The capacity purchase cost is based on the economic carrying charge for a simple-cycle combustion turbine. The price used for the combustion turbine is based on the Midwest ISO's 2011 cost of new entry approved rate. This cost is assumed to be the avoided capacity cost in the respective years. The following table provides a summary of the capacity purchase amounts and capacity costs.

Table 5: Summary of Capacity Purchase Amounts and Costs

	Base Requirements Before Resource Expansion		Requirements Assuming Alternate 1 Expansion with Illinois Power Agency	
Year	**Purchase (MW)**	**Capacity Cost ($/kWh)**	**Purchase (MW)**	**Capacity Cost ($/kWh)**
2016	48	89.32		89.32
2017	111	91.55		91.55
2018	171	93.84		93.84
2019	241	96.18		96.18
2020	316	98.59		98.59
2021	391	101.05		101.05
2022	438	103.58		103.58
2023	483	$106.17		$106.17
2024	536	$108.82	10	$108.82
2025	725	$111.54	196	$111.54
2026	770	$114.33	238	$114.33
2027	826	$117.19	291	$117.19
2028	882	$120.12	344	$120.12
2029	990	$123.12	448	$123.12
2030	1,049	$126.20	504	$126.20
2031	1,111	$129.36	562	$129.36
2032	1,159	$132.59	607	$132.59
2033	1,667	$135.91	1,111	$135.91

Q. Did you prepare cost information for the first power plant option specified in the Company's capacity expansion as required in 199 Iowa Administrative Code 35.9(6)"c"?

A. Yes. My testimony includes the following information with regard to the first power plant option in response to 199 IAC 35.9(6)"c":

- The anticipated life of the power plant option is 25 years.
- The anticipated total capital cost is $704/kW in 2011 dollars including AFUDC.
- The anticipated annual revenue requirement of capital costs is provided in Exhibit___(ODS-1), Schedule 10, page 2, under the column labeled "NPV Capital."

- The anticipated revenue requirement of the annual fixed operations and maintenance costs is provided in Exhibit___(ODS-1), Schedule 10, page 2, under the column labeled "Fixed O&M." Property taxes are included as a variable cost in Iowa.
- The anticipated net present value of the revenue requirements per net kW is provided in Exhibit___(ODS-1), Schedule 10, page 2, under the column labeled "NPV Total."
- The anticipated revenue requirement per net kW per year calculated by utilization of an economic carrying charge is provided in Exhibit___(ODS-1), Schedule 10, page 1, under the column labeled "Total Annual Avoided Economic Carrying Charge including RM, DLF & EF" where RM, DLF and EF are reserve margin, demand loss factor and externality factor, respectively.
- The after-tax discount rate used to calculate the revenue requirement per net kW per year over the life of the supply option is 6.61 percent.
- The inflation rate for capital costs and for other annual costs such as fixed operation and maintenance is 2.5 percent.

Q. Does your testimony include information on electric avoided capacity and energy costs as required by 199 Iowa Administrative Code 35.9(7)?

A. Yes. Avoided capacity costs based on the peaker method are provided in Exhibit___(ODS-1), Schedule 10 on page 1, the avoided generation, transmission and distribution costs are summarized in Exhibit___(ODS-1), Schedule 11 and the energy costs are provided in Exhibit___(ODS-1), Confidential Schedule 11 for the period 2013 through 2033. MidAmerican

witness Jennifer L. Long addresses the calculation of the transmission and distribution avoided costs. The annual avoided energy costs are based on a simulation of the hourly avoided costs of MidAmerican's generating units and any off-system energy purchases.

Q. Please describe the avoided capacity cost calculations used for each costing period pursuant to 199 Iowa Administrative Code 35.9(7)"a".

A. The Company used the installed cost of a combustion turbine as a proxy for the capacity cost of all future capacity additions. This is commonly referred to as the peaker method. The Company's first capacity deficiency occurs in 2023 for the resource plan summarized in Exhibit ___(ODS-1), Schedule 9a. The 2011 overnight installed cost, including interconnection costs and allowance for funds during construction (AFUDC) for a combustion turbine is $704/kW. The anticipated annual revenue requirement of the capital costs were calculated, as shown in Exhibit___(ODS-1), Schedule 10 on page 2, and then the annual net present values (2012 basis) for the capital costs were calculated.

Likewise, the anticipated revenue requirements associated with the annual fixed operation and maintenance costs[4] were escalated (using respective escalation factors) for each year of the revenue requirement period and then the net present values for each year were calculated. Finally, the annual net present values of capital costs and the expenses were summed and the annual values were totaled.

[4] The property tax statute currently allows property taxes to be collected through an energy-based charge.

The present value of revenue requirements is then converted into an annual amount using an economic carrying charge that is described in 199 IAC 35.9(6)"c"(6). The economic carrying charge is given by the formula:

$$ECC_t = k \times [(r - [(1+i) / (1+b)] - 1] \times \{(1+r)^n / \{(1+r)^n - [(1+i) / (1+b)]^n\}\}$$

Where: ECC_t = Economic carrying charge in year "t"

k = Present value of revenue requirement

n = Expected life of investment

i = Inflation rate

r = Discount rate

b = Technical progress

The adjustment for potential future generation technology improvements was set to zero to reflect a conservative view with respect to energy efficiency development. Technology improvements can be exemplified in several ways, including reduced cost per unit of capacity, improved efficiency, reduced emissions, reduced operating and maintenance costs and increased availability. Such improvements rarely increase uniformly through time and are generally driven by factors such as need and economics.

Operating improvements in future generation also are expected. Such improvements would likely be reflected through a reduction in heat rates, emissions and operating and maintenance costs and increased unit availability. The Company declined to include an adjustment for operating improvements at this time due to the sparse data and trends as to when technology improvements

would become available in the market place. These improvements would tend to reduce the avoided energy cost. MidAmerican does, however, use the latest proven technology as the prototype to model future units.

The avoided capacity costs are adjusted for the projected Midwest ISO planning reserve margins, capacity losses and externalities. The Midwest ISO planning reserve margin used was 12.0 percent for 2013 (based on the 2011 Midwest ISO planning reserve margins used for MidAmerican's avoided cost filing in July 2012). An 8.01 percent loss factor, developed by MidAmerican Delivery Services, was used to reflect the losses from the generator to the customers' meters. The prescribed 10 percent externality factor is used to recognize other non-quantifiable benefits of energy efficiency (199 Iowa Administrative Code 35.9(7)"a").

Q. Please describe the avoided energy cost calculations used for each costing period pursuant to 199 Iowa Administrative Code 35.9(7)"b".

A. MidAmerican developed the avoided energy costs using a probabilistic, chronological, hourly-dispatch, production cost model.[5] MidAmerican's loads, generation operating characteristics, fuel costs, emission costs and rates and off-system purchase costs are modeled in detail. The dispatch model uses a Monte Carlo random outage algorithm to simulate random forced outages of generators. MidAmerican developed representative results for each hour by using a feature of the model that averages the results of multiple iterations. The purchases required to meet loads during periods of insufficient generation are

[5] MidAmerican uses ABB Ventyx's PROMOD IV production cost model.

based on a market price projection[6] for each hour. A summary of annual average marginal costs is provided in Exhibit___(ODS-1), Confidential Schedule 12.

Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

[6] The market price projection has been developed by MidAmerican using ABB Ventyx's MarketPower pricing model.

FILED WITH
Executive Secretary
February 01, 2013
IOWA UTILITIES BOARD

STATE OF IOWA

BEFORE THE IOWA UTILITIES BOARD

IN RE:	:	
MIDAMERICAN ENERGY COMPANY	:	**Docket No. EEP-2012-0002**

AFFIDAVIT
OF
O DALE STEVENS

STATE OF IOWA)
) ss.
COUNTY OF POLK)

I, O. Dale Stevens, being first duly sworn on oath, depose and state that I am the same O. Dale Stevens, identified in the Direct Testimony; that I have caused the Direct Testimony, to be prepared and am familiar with the contents thereof; and that the Direct Testimony, is true and correct to the best of my knowledge and belief as of the date of this Affidavit.

/s/ O. Dale Stevens
O. Dale Stevens

SUBSCRIBED AND SWORN TO before me this 31st day of, January, 2013.

/s/ Sherri Long
Notary Public in and for the State of Iowa
My commission expires on March 30, 2014