Integrated Resource Plan

for

Municipal Energy Agency of Nebraska

October 2007

Nebraska Municipal Power Pool
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Section I. Executive Summary

Introduction

The Integrated Resource Plan (IRP) for the Municipal Energy Agency of Nebraska (MEAN) was developed to meet MEAN's resource requirements for the 10-year period beginning Fiscal Year (FY) 2007-2008 through FY 2016-2017. MEAN's FY runs April 1 through March 31.

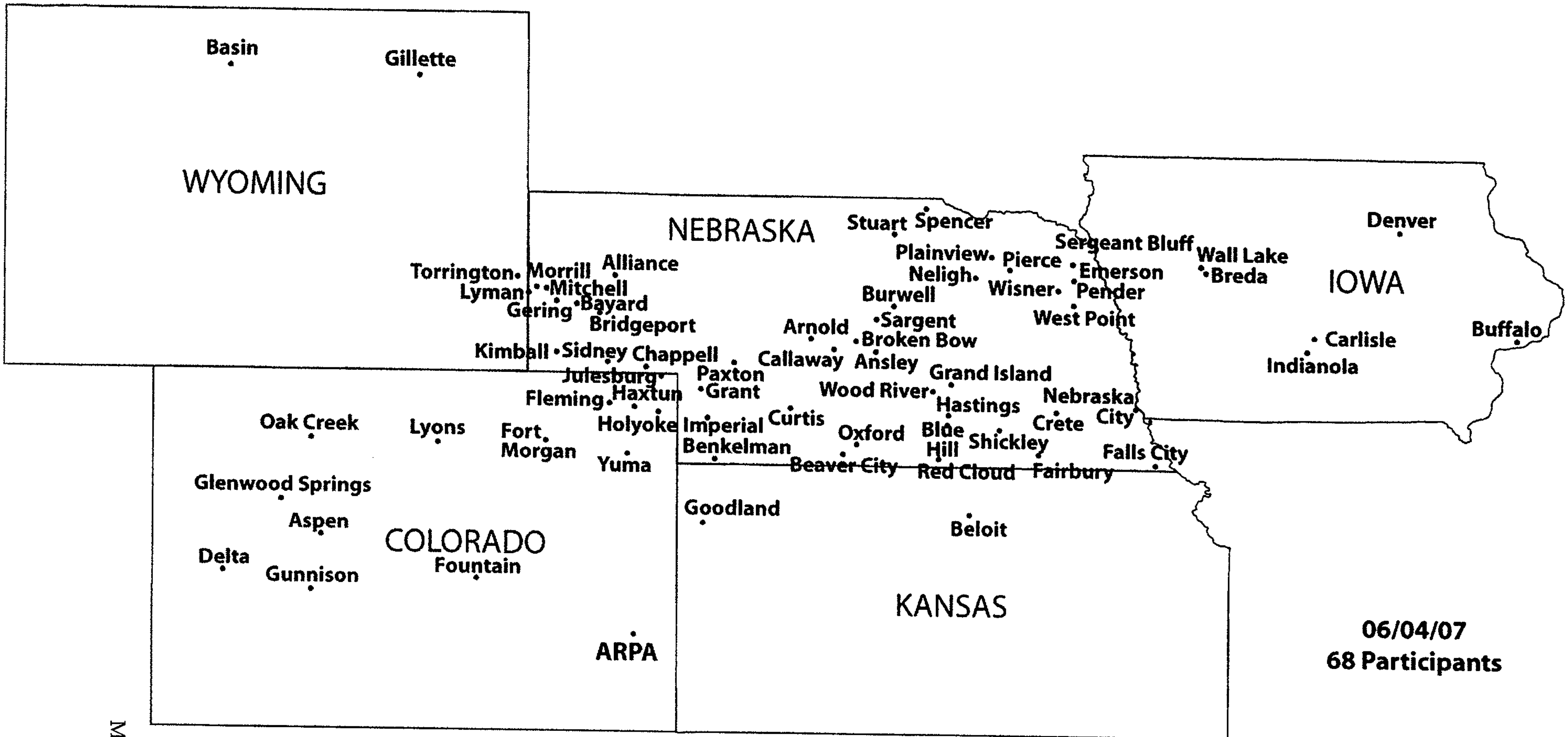
MEAN is a municipal joint action agency and political subdivision of the State of Nebraska. Established in 1981, MEAN provides electricity and related services to 66 member communities, one public power district and one joint action agency in five states: Colorado, Iowa, Kansas, Nebraska, and Wyoming. As of July 31, 2007, 60 of the 68 members are Total Requirements Participants (TRP). The TRP purchase from MEAN all power supply requirements not provided by Western Area Power Administration (Western). The remaining eight members, who are not TRP, purchase energy from MEAN as needed. Services for TRP include: energy audits, community and economic development, electric distribution services, load factor improvement, member training, scholarships, Cost of Service and Rate Design Studies (COS/RDS), and energy cost analysis. Figure 1 (*page 2*) shows MEAN's members and their geographical locations.

Purpose

The purpose of MEAN is to plan, acquire, finance and operate facilities to generate and transmit electric power and energy to its TRP. As part of MEAN's prudent planning effort and continued commitment to its TRP, MEAN prepares and updates its IRP on an ongoing basis.

The purpose of this IRP is to develop long-range implementation plans to serve the TRP power supply requirements consistent with prudent utility planning practices.

Figure 1



06/04/07
68 Participants

MEAN
Municipal Energy Agency of Nebraska
Participants

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In November 1995, Western established a program called the Energy Planning and Management Program (EPAMP), which enables its customers to maintain their current allocations of capacity and energy from Western. EPAMP requires its customers to prepare and submit an IRP to Western every five years. This IRP is intended to meet the requirements of the EPAMP as well as be used as a planning document for MEAN. In 2002, MEAN submitted its IRP to Western and has implemented several of the recommendations from that IRP, including participation in the Council Bluffs Energy Center 4 and Whelan Energy Center 2 projects.

Current MEAN System

The MEAN system includes owned and purchased power supply resources, transmission system arrangements used to transmit MEAN resources to the TRP, and Demand Side Management (DSM) options.

Power Supply Resources

At the time this IRP was prepared, MEAN has more than 500 MW of power supply resources. MEAN has sold 30 MW of capacity and energy through April 2014. West Side and East Side resources are shown in Tables 1 and 2 (*page 4*), respectively.

Transmission Service Arrangements

MEAN serves its TRP with transmission service from eight transmission providers:

1. Black Hills Power and Light (BHPL)
2. Colorado Springs Utilities (CSU)
3. Mid-American Energy Company (MEC)
4. Nebraska Public Power District (NPPD)
5. Public Service Company of Colorado (PSCo)
6. Tri-State Generation and Transmission (Tri-State G&T)
7. Western – Rocky Mountain Region (Western-RMR)
8. Western – Salt Lake City Area Projects (Western-SLCA)

Table 1
West Side
Existing and Committed Generation Resource

Generation Facility	Resource	Capacity (MW)	Expiration	Primary Energy Source
Bulk Power Participants	Facilities Committed under Pooling Agreements	45.1	None	Oil/Natural Gas
WAPA	Firm Electric Service	116.5	September 2024	Hydroelectric
Black Hills Power and Light (1)	Neil Simpon 2 and Wygen 1	40.0	February 2013	Coal
Lincoln Electric System	Laramie River Station Units 2 and 3	18.0	Life of plant	Coal
Platte River Power Authority (2)	System Participation	10.0	December 2007	Coal
Public Service Company of Colorado	Purchase Power	26.0	September 2007	Purchase
Short Term Purchases	Purchase Power	20.0	August 2007	Purchase
MEAN Wind Project at Kimball	Renewable Intermittent Resource (Wind)	0.0	Life of plant	10.5 MW Nameplate Wind
West Subtotal		**275.6**		

1. Expires February 2013, Conversion to permanent ownership is being negotiated
2. Expires December 31, 2007, Contract extension to December 2008 is being negotiated

Table 2
East Side
Existing and Committed Generation Resource

Generation Facility	Resource	Capacity (MW)	Expiration	Primary Energy Source
Bulk Power Participants	Facilities Committed under Pooling Agreements	90.0	None	Oil/Natural Gas
WAPA	Firm Electric Service	31.4	September 2024	Hydroelectric
NPPD [1]	Cooper Nuclear Station	60.0	April 2014	Nuclear
NPPD [2]	Gerald Gentleman Station	40.0	April 2014	Coal
Lincoln Electric System	Laramie River Station Unit 1	10.0	Life of plant	Coal
Hastings, NE	System Participation	10.0	April 2009	Coal/Natural Gas
Hastings, NE	Hastings Energy Center	5.0	Life of plant	Coal
Mid American Energy Company	Council Bluffs 4	52.7	Life of plant	Coal
MEC Participation Waverly, IA	Council Bluffs 4 Participation	3.2	February 2010	Coal
Public Power Generation Agency (3)	Whelan Energy Center 2	0.0	Life of plant	Coal
Short Term Purchase	Purchased Capacity	30.0	August 2007	Purchase
Ainsworth Wind Energy Facility	Renewable Intermittent Resource (Wind)	0.0	Life of plant	7.0 MW Nameplate Wind
East Resource Total		**332.3**		
Basin Electric Power Cooperative	Unit Participation Sale	-30.0	April 2014	Capacity and Energy Sale
East Subtotal		**302.3**		
Current MEAN System Net Total		**577.9**		

1. Expires April 30, 2014; total contract delivery may be reduced to 30 MW when Whelan Energy Center 2 is commercially operational
2. Expires April 30, 2014; total contract delivery may be reduced to 20 MW when Whelan Energy Center 2 is commercially operational
3. Projected Online Date 2011, MEAN will participate in 80 MW of 220 MW

Demand Side Management Program

MEAN assists the TRP with implementation and maintenance of DSM programs, including:

- Software and software support for direct load control
- Commercial and industrial energy audits
- Funding one-third of the cost for Cost of Service and Rate Design Studies (COS/RDS) for TRP

Load Forecast

A load forecast was prepared to project the TRP peak demand and energy requirements for the period FY 2007-2008 through FY 2016-2017. The forecast incorporated econometric forecasting methods to relate historical energy consumption to population growth, real per capita income, employment, number of electric utility consumers, heating and cooling degree days, and the real wholesale or retail price of electricity. Subsequently, forecasted econometric variables were used to project energy consumption.

The Peak Demand and Energy Requirements load forecast is summarized in Tables 3 and 4 (*pages 6 and 7*). The reduction in peak demand and energy requirements in FY 2008-2009 is the result of one TRP contract expiring. The projected average annual compound growth rate for peak demand is 3.0% for the West Side and 1.6% for the East Side for the period FY 2009-2010 through FY 2016-2017. The energy requirements forecast is summarized in Figures 2 and 3 (*pages 8 and 9*). The projected average annual compound growth rate for energy requirements is 3.1% for the West Side and 1.5% for the East Side for the period FY 2009-2010 through FY 2016-2017.

Table 3
West Side Participants
Historical and Projected
Peak Demand and Energy Requirements

Year	Total Peak Demand Summer MW	Winter MW	Percent Change	Total Energy Requirements Summer MWh	Winter MWh	Total MWh	Percent Change	Load Factor DLC %
1990-1991	45.8	52.2		78,021	176,784	254,805		55.76%
1991-1992	46.0	48.4	0.31%	77,966	175,114	253,080	-0.07%	59.65%
1992-1993	43.1	86.2	-6.23%	75,128	288,742	363,870	-3.64%	48.03%
1993-1994	75.6	86.1	75.47%	140,204	321,413	461,617	86.62%	61.24%
1994-1995	78.1	93.7	3.29%	155,506	342,337	497,843	10.91%	60.67%
1995-1996	90.6	98.0	15.95%	162,221	362,951	525,172	4.32%	61.15%
1996-1997	100.8	126.4	11.28%	166,804	404,086	570,890	2.83%	51.41%
1997-1998	114.3	122.4	13.40%	167,931	457,694	625,625	0.68%	58.35%
1998-1999	131.7	136.6	15.24%	164,791	496,157	660,948	-1.87%	55.23%
1999-2000	134.6	124.4	2.18%	168,901	500,571	669,472	2.49%	61.45%
2000-2001	140.0	136.7	3.99%	168,791	545,667	714,459	-0.06%	59.50%
2001-2002	143.2	132.0	2.31%	167,341	559,596	726,936	-0.86%	62.86%
2002-2003	153.8	156.2	7.41%	251,968	514,698	766,666	-8.02%	56.90%
2003-2004	181.8	170.0	18.20%	291,859	578,915	870,774	12.48%	54.68%
2004-2005	179.9	224.8	-1.06%	283,683	734,348	1,018,031	26.85%	64.61%
2005-2006	306.7	282.9	70.54%	480,151	927,636	1,407,787	26.32%	52.39%
2006-2007	323.2	285.1	5.36%	533,576	1,017,571	1,551,147	9.70%	54.79%
2007-2008	323.8	291.4	0.19%	490,537	1,029,600	1,520,137	1.18%	53.59%
2008-2009	258.5	232.6	-20.17%	463,249	993,095	1,456,344	-5.56%	59.71%
2009-2010	266.1	239.4	2.93%	479,771	985,110	1,464,881	3.57%	59.71%
2010-2011	275.2	247.7	3.43%	496,134	1,019,015	1,515,149	3.41%	59.71%
2011-2012	283.9	255.5	3.18%	511,812	1,051,501	1,563,313	3.16%	59.71%
2012-2013	292.7	263.4	3.09%	527,531	1,084,074	1,611,605	3.07%	59.71%
2013-2014	301.5	271.4	3.01%	543,326	1,116,803	1,660,128	2.99%	59.71%
2014-2015	310.4	279.4	2.95%	559,294	1,149,890	1,709,184	2.94%	59.71%
2015-2016	319.3	287.4	2.86%	575,195	1,182,838	1,758,033	2.84%	59.71%
2016-2017	328.1	295.3	2.75%	590,935	1,215,454	1,806,390	2.74%	59.71%

Table 4
East Side Participants
Historical and Projected
Peak Demand and Energy Requirements

Year	Total Peak Demand			Total Energy Requirements				Load Factor
	Summer MW	Winter MW	Percent Change	Summer MWh	Winter MWh	Total MWh	Percent Change	%
1990-1991	111.4	91.9		181,932	316,775	498,707		51.09%
1991-1992	111.4	85.7	0.01%	187,312	317,981	505,293	2.96%	51.76%
1992-1993	100.6	91.1	-9.70%	167,243	341,949	509,192	-10.71%	57.61%
1993-1994	110.3	92.1	9.59%	176,696	341,015	517,711	5.65%	53.59%
1994-1995	109.9	89.5	-0.35%	190,021	338,292	528,313	7.54%	54.88%
1995-1996	119.3	102.5	8.56%	199,886	355,910	555,797	5.19%	53.18%
1996-1997	120.9	105.2	1.34%	197,374	374,586	571,960	-1.26%	53.86%
1997-1998	125.0	94.3	3.42%	209,421	368,612	578,033	6.10%	52.77%
1998-1999	123.4	100.0	-1.30%	207,379	352,967	560,347	-0.98%	51.83%
1999-2000	128.4	93.9	4.04%	205,770	351,424	557,193	-0.78%	49.54%
2000-2001	131.9	108.6	2.69%	223,303	387,790	611,093	8.52%	52.76%
2001-2002	133.8	100.3	1.50%	219,660	380,838	600,498	-1.63%	51.22%
2002-2003	140.9	117.2	5.32%	238,786	394,895	633,681	8.71%	51.33%
2003-2004	139.9	116.5	-0.73%	230,552	402,520	633,072	-3.45%	51.66%
2004-2005	145.7	131.3	4.15%	223,314	433,781	657,095	-3.14%	51.49%
2005-2006	160.7	144.3	10.29%	265,913	479,584	745,496	19.08%	52.96%
2006-2007	168.6	146.3	4.94%	277,583	503,914	781,496	4.39%	52.91%
2007-2008	197.2	177.5	16.96%	299,029	600,584	899,612	7.73%	52.07%
2008-2009	203.2	182.9	3.05%	365,961	652,897	1,018,859	22.38%	52.07%
2009-2010	207.1	186.4	1.89%	372,047	665,261	1,037,308	1.66%	52.07%
2010-2011	210.6	189.5	1.68%	378,047	675,995	1,054,042	1.61%	52.07%
2011-2012	213.8	192.4	1.53%	383,599	685,928	1,069,528	1.47%	52.07%
2012-2013	217.0	195.3	1.51%	389,174	695,901	1,085,075	1.45%	52.07%
2013-2014	220.3	198.2	1.49%	394,740	705,859	1,100,600	1.43%	52.07%
2014-2015	223.5	201.1	1.46%	400,282	715,775	1,116,057	1.40%	52.07%
2015-2016	226.7	204.1	1.45%	405,870	725,771	1,131,640	1.40%	52.07%
2016-2017	230.0	207.0	1.44%	411,508	735,857	1,147,365	1.39%	52.07%

Figure 2
Energy Requirements Forecast
West Side

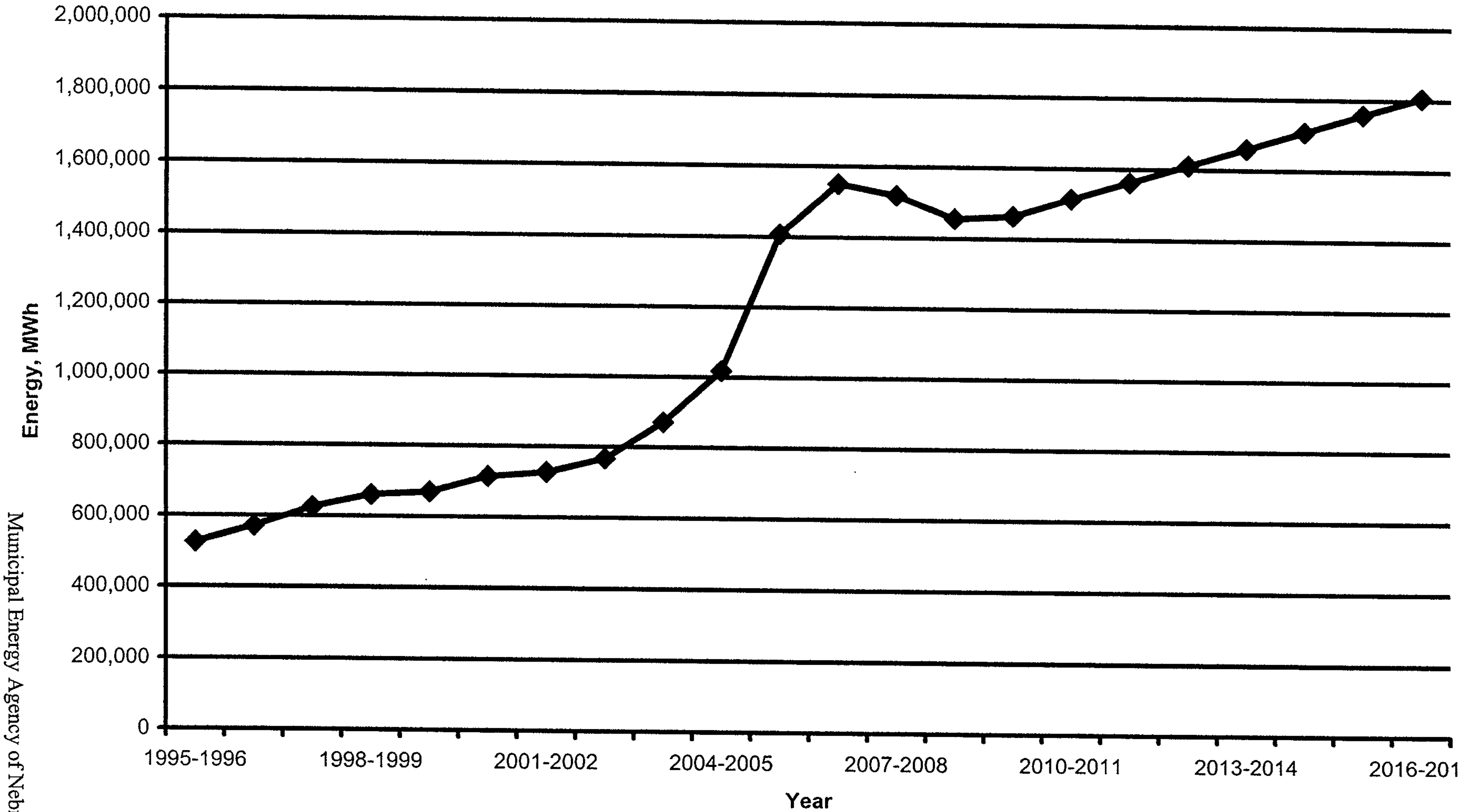
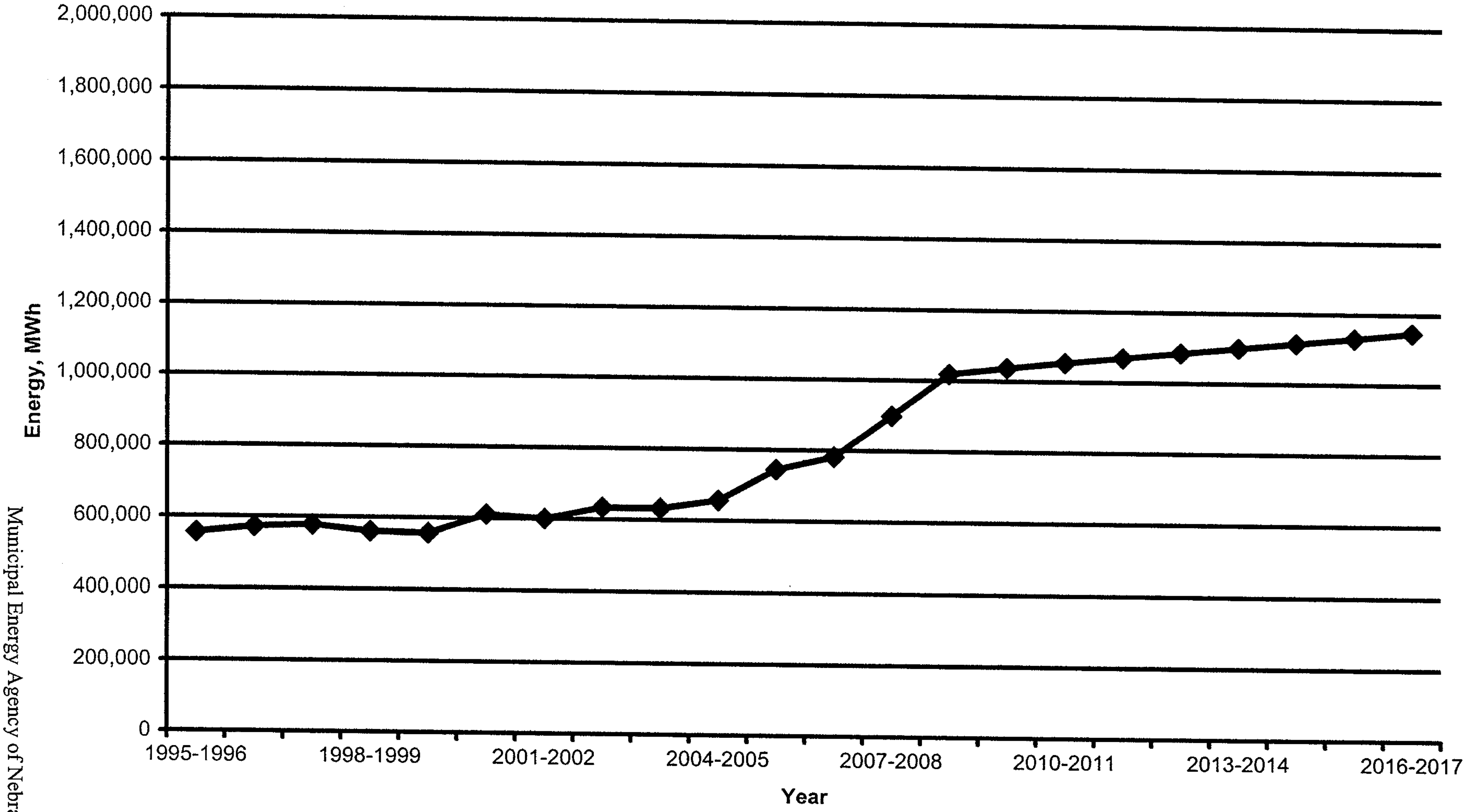


Figure 3
Energy Requirements
Forecast East Side



Comparison of Demand and Energy Requirements to Resources

Forecasted peak demand and energy requirements were summarized and compared to existing capacity and energy resources. Tables 5 and 6 (*page 12*) summarize the Comparison of Peak Demand and Energy Requirements to Resources for the West Side and the East Side, respectively. Based on the Comparison of Peak Demand and Energy Requirements to Resources, the following was concluded:

- MEAN is capacity deficit on the West Side by approximately 40 MW in FY 2007-2008, not including Sidney AC/DC/AC tie transfers. The capacity deficit increases to approximately 193 MW in FY 2016-2017.
- MEAN is energy deficit on the West Side by approximately 363,000 MWh in FY 2007-2008, not including Sidney AC/DC/AC tie transfers. The energy deficit increases to approximately 1,245,000 MWh in FY 2016-2017.
- The capacity factor of the West Side demand and energy requirements indicates that MEAN resource needs are intermediate to baseload in nature.
- MEAN is capacity deficit on the East Side for the periods of FY 2009-2011 and FY 2014-2017. The maximum deficit is 28 MW in FY 2016-2017.
- MEAN is energy surplus on the East Side by approximately 422,943 MWh in FY 2007-2008. The energy surplus decreases to 150,313 MWh in FY 2016-2017.
- The East Side demand requirements and energy surplus indicates that MEAN resource needs are peaking in nature.

Supply-Side Resource Evaluation

The EPAMP indicates the IRP should consider all practicable energy supply resource options. The resource options considered in this IRP include generic options and specific options that are currently available to MEAN in the Midwest Reliability Organization (MRO) and the Western Electric Coordinating Council (WECC) areas. The following options were considered to meet MEAN's resource needs:

- West Side Options
  a. Coal-fired baseload 40 MW unit ownership in Wyoming
  b. East Side coal-fired baseload unit and expansion of the Sidney AC/DC/AC Tie
  c. On-peak capacity and energy purchases
  d. Proposed hydroelectric and pumped storage facility in Colorado
  e. Proposed waste coal-fired unit in Wyoming
  f. Short term natural gas combined cycle participation in Colorado (2010-2013)
  g. Wind resource proposals in Colorado and Western Nebraska
- East Side Options
  a. Proposed baseload coal-fired units in Iowa
  b. Proposed compressed air storage and natural gas fired unit in Iowa
  c. Short-term peaking capacity purchases
  d. Wind resource proposals in Iowa, Nebraska, and South Dakota

Table 5
Comparison of Peak Demand and Enegy Requirements to Resources
West Side

	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017
Demand, MW										
Projected Demand	323.8	258.5	266.1	275.2	283.9	292.7	301.5	310.4	319.3	328.1
Required Reserves (1)	26.0	20.2	21.3	22.8	24.1	25.5	26.8	28.1	29.4	30.8
Peak Demand Obligation	349.8	278.7	287.4	298.0	308.1	318.2	328.3	338.5	348.7	358.8
Capacity Resources	309.6	206.9	206.9	206.1	206.1	206.1	166.1	166.1	166.1	166.1
Surplus/(Deficit)	**(40.2)**	**(71.7)**	**(80.4)**	**(91.9)**	**(101.9)**	**(112.0)**	**(162.2)**	**(172.4)**	**(182.6)**	**(192.7)**
Energy, MWh										
Energy Obligation	1,520,137	1,456,344	1,464,881	1,515,149	1,563,313	1,611,605	1,660,128	1,709,184	1,758,033	1,806,390
Energy Resources	1,157,089	861,431	861,431	858,960	858,960	858,960	561,120	561,120	561,120	561,120
Surplus/(Deficit)	**(363,048)**	**(594,913)**	**(603,450)**	**(656,188)**	**(704,352)**	**(752,644)**	**(1,099,008)**	**(1,148,064)**	**(1,196,913)**	**(1,245,269)**
Deficit Capacity Factor	103%	95%	86%	82%	79%	77%	77%	76%	75%	74%

Notes:
(1) 15% required reserves for load not supplied by firm resources

Table 6
Comparison of Peak Demand and Enegy Requirements to Resources
East Side

	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017
Demand, MW										
Projected Demand	197.2	203.2	207.1	210.6	213.8	217.0	220.3	223.5	226.7	230.0
Firm Sales	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Required Reserves (1)	30.0	30.6	31.1	31.7	32.2	32.7	33.2	33.6	34.1	34.6
Peak Demand Obligation	261.2	267.8	272.2	276.2	280.0	283.7	287.4	291.1	294.9	298.6
Capacity Resources	302.3	274.4	264.4	261.3	291.0	291.0	291.0	271.0	271.0	271.0
Surplus/(Deficit)	**41.1**	**6.6**	**(7.8)**	**(15.0)**	**11.1**	**7.3**	**3.6**	**(20.1)**	**(23.8)**	**(27.6)**
Energy, MWh										
Energy Obligation	899,612	1,018,859	1,037,308	1,054,042	1,069,528	1,085,075	1,100,600	1,116,057	1,131,640	1,147,365
Energy Resources	1,322,555	1,322,555	1,248,095	1,224,291	1,446,598	1,446,598	1,446,598	1,297,678	1,297,678	1,297,678
Surplus/(Deficit)	**422,943**	**303,697**	**210,788**	**170,249**	**377,070**	**361,523**	**345,998**	**181,621**	**166,038**	**150,313**

Notes:
(1) 15% required reserves for load not supplied by firm resources

Demand Side Analysis

Several DSM options were considered as a means of deferring new capacity resource acquisitions. MEAN selected three primary load shape objectives:

1. Peak Clipping
2. Strategic Conservation
3. Valley Filling

DSM options that satisfy these load shape objectives were selected for further evaluation.

DSM Screening and Analysis

DSM options that achieve the selected load shape objectives were screened. The DSM screening involved qualitative and economic screening. Three of the 16 options evaluated had positive net present values, indicating economic benefit to the TRP, over the 10-year study period:

a. Interruptible rates
b. Commercial high efficiency lighting
c. Compact fluorescent lighting

The option with the highest positive present value is interruptible rates. MEAN supports interruptible rates through financial assistance to members that conduct a COS/RDS which can identify interruptible rate options when feasible. MEAN's rates, through demand charges and ratchets, also provide a rate signal to the TRP to implement interruptible rates where practicable.

Another economically feasible option is commercial high efficiency lighting. MEAN plans to investigate a new commercial high efficiency lighting program in conjunction with energy audits already offered to our commercial and industrial customers. The program would offer rebates and other assistance to end-use customers who install high efficiency lighting.

MEAN also plans to investigate a new program to encourage end-use customers to purchase compact fluorescent lighting. The new program would offer rebates to help offset the difference in price between compact fluorescent bulbs and incandescent bulbs. The program would also encourage the proper disposal of the bulbs at the end of their service life.

Supply/Demand Integration

The purpose of supply/demand integration is to incorporate DSM options with the practicable resources from the supply screening. The economical DSM options are not projected to change MEAN's resource needs in the near term.

Interruptible rates can reduce the need for future capacity by reducing individual TRP peak demand and, thus, MEAN's peak demand obligation; however, it is difficult to quantify the potential demand reduction because end-use customer acceptance and use is unknown. Commercial high efficiency lighting would provide demand reduction, but the market potential for this measure is not anticipated to be significant in the near term. Compact fluorescent bulbs are not anticipated to reduce the need for capacity in the near term. While energy savings will occur with compact fluorescents, the energy savings will not reduce the need for baseload to intermediate resources to supply the MEAN energy and capacity deficits in the near term.

Preferred Integrated Resource Plan

Several supply-side cases were evaluated using two spreadsheet models to determine practicable resources. The first model produced the resource screening curves for energy production costs in 2012 dollars. The second model calculated annual production requirements based on existing load forecasts and 2006 hourly load data. Further information on this process can be found in Section VII, Development of Preferred Plan.

Other Considerations

Other factors entered into MEAN's selection of a preferred resource plan, including schedule, resource availability, and risk mitigation. See Section VII, Development of Preferred Plan, for additional information. The plan selected is reasonable given economic, environmental and other considerations.

Conclusions

Based on the assumptions used and analyses completed, the following was concluded:

1. MEAN is capacity deficit on the West Side by approximately 40 MW in FY 2007-2008, not including Sidney AC/DC/AC tie transfers. The capacity deficit increases to approximately 193 MW in FY 2016-2017.
2. MEAN is energy deficit on the West Side by approximately 363,000 MWh during FY 2007-2008, not including Sidney AC/DC/AC tie transfers. The capacity deficit increases to approximately 1,245,000 MWh in FY 2016-2017.
3. The capacity factor of the West Side demand and energy requirements indicates that MEAN resource needs are intermediate to baseload in nature.
4. MEAN is capacity deficit on the East Side for the periods of FY 2009-2011 and FY 2014-2017. The maximum deficit is 28 MW in FY 2016-2017.
5. MEAN is energy surplus on the East Side by approximately 422,943 MWh in FY 2007-2008. The surplus is projected to decrease to 150,313 MWh in FY 2016-2017.
6. The capacity factor of the East Side demand and energy requirements indicates that MEAN resource needs are peaking in nature.
7. Purchasing capacity and participating in new generating units were considered.
8. The feasible West Side resource options during the 10-year study period were:
    a. Coal-fired baseload 40 MW unit ownership in Wyoming
    b. East Side coal-fired baseload unit and expansion of the Sidney AC/DC/AC Tie
    c. On-peak capacity and energy purchases
    d. Proposed waste coal-fired unit in Wyoming
    e. Short-term natural gas combined cycle participation in Colorado (2010-2013)
    f. Wind resource proposals in Colorado and Western Nebraska

9. The feasible East Side resource options during the 10-year study period were:
   a. Short-term peaking capacity purchases
   b. Wind resource proposals in Iowa, Nebraska, and South Dakota
10. DSM options that resulted in net benefits to the TRP included the implementation of interruptible rates as well as the installation of compact fluorescent bulbs and high efficiency commercial lighting.

Recommendations/Action Plan

Based on the assumptions used, analyses completed, and conclusions reached, the following IRP is recommended. The recommended resource additions are shown in Tables 7 and 8 (*see page 17*) for the West Side and East Side, respectively. Figures 4 and 5 (*pages 18 and 19*) show the integration of the resource additions with MEAN's existing resources.

- West Side
  - Continue to explore other practicable supply options
  - Investigate combined cycle natural gas-fired unit participation
  - Investigate additional West Side baseload generation
    - East Side baseload and Sidney AC/DC/AC Tie expansion
    - West Side baseload units
  - On-peak capacity and energy purchases
  - Purchase power agreements for wind energy to meet member requests
- East Side
  - Continue to explore other practicable supply options
  - Purchase power agreements for wind energy to meet member requests
  - Short-term peaking capacity purchases
- Investigate DSM options involving compact fluorescent bulbs and high efficiency commercial lighting

Table 7
Resource Additions
Recommended Integrated Resource Plan
West Side

	Fiscal Year									
	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017
Peak Demand Obligation (1)	349.8	278.7	287.4	298.0	308.1	318.2	328.3	338.5	348.7	358.8
West Member Gen	45.1	25.1	25.1	25.1	25.1	25.1	25.1	25.1	25.1	25.1
WAPA	116.5	89.8	89.8	89.0	89.0	89.0	89.0	89.0	89.0	89.0
Black Hills Power and Light	40.0	40.0	40.0	40.0	40.0	0.0	0.0	0.0	0.0	0.0
Laramie River Station	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Platte River Power Authority	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service Company of Colorado	26.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WAPA Displacement	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Sidney DC Tie	41.0	37.0	36.0	24.0	35.0	40.0	38.0	39.0	40.0	40.0
Baseload Addition 1						**40.0**	**40.0**	**40.0**	**40.0**	**40.0**
Combined Cycle				**68.0**	**68.0**	**68.0**	**0.0**	**0.0**	**0.0**	**0.0**
Baseload Addition 2							**80.0**	**80.0**	**80.0**	**80.0**
On-Peak Capacity/Energy	**20.0**	**35.0**	**45.0**	**0.0**	**0.0**	**5.0**	**5.0**	**15.0**	**25.0**	**35.0**
Capacity/Reserve	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Surplus/(Deficit)	0.8	0.2	0.5	0.1	1.0	1.0	0.8	1.6	2.4	2.3

Notes:
(1) Included forecast demand and 15% required reserves for load not supplied by firm resources.

Table 8
Resource Additions
Recommended Integrated Resource Plan
East Side

	Fiscal Year									
	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017
Peak Demand Obligation (1)	261.2	267.8	272.2	276.2	280.0	283.7	287.4	291.1	294.9	298.6
East Member Gen	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
WAPA	31.4	33.5	33.5	33.4	33.2	33.2	33.2	33.2	33.2	33.2
NPPD Cooper	60.0	60.0	60.0	60.0	30.0	30.0	30.0	0.0	0.0	0.0
NPPD GGS	40.0	40.0	40.0	40.0	20.0	20.0	20.0	0.0	0.0	0.0
Laramie River Station	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Hastings Purchase	10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
MEC Council Bluffs 4	52.7	52.7	52.7	52.7	52.7	52.7	52.7	52.7	52.7	52.7
CB 4 Waverly Purchase	3.2	3.2	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC 2	0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	80.0	80.0
Sale to BEPC	-30.0	-30.0	-30.0	-30.0	-30.0	-30.0	-30.0	0.0	0.0	0.0
Sidney DC Tie	-41.0	-37.0	-36.0	-24.0	-35.0	-40.0	-38.0	-39.0	-40.0	-40.0
Baseload Addition	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
On Peak Capacity/Energy	**30.0**	**35.0**	**45.0**	**40.0**	**35.0**	**35.0**	**35.0**	**60.0**	**65.0**	**70.0**
Surplus/(Deficit)	0.0	4.5	1.1	0.8	10.9	2.1	0.4	0.7	1.0	2.2

Notes:
(1) Included forecast demand and 15% required reserves for load not supplied by firm resources.

Figure 4 Resource Additions Recommended Integrated Resource Plan West Side

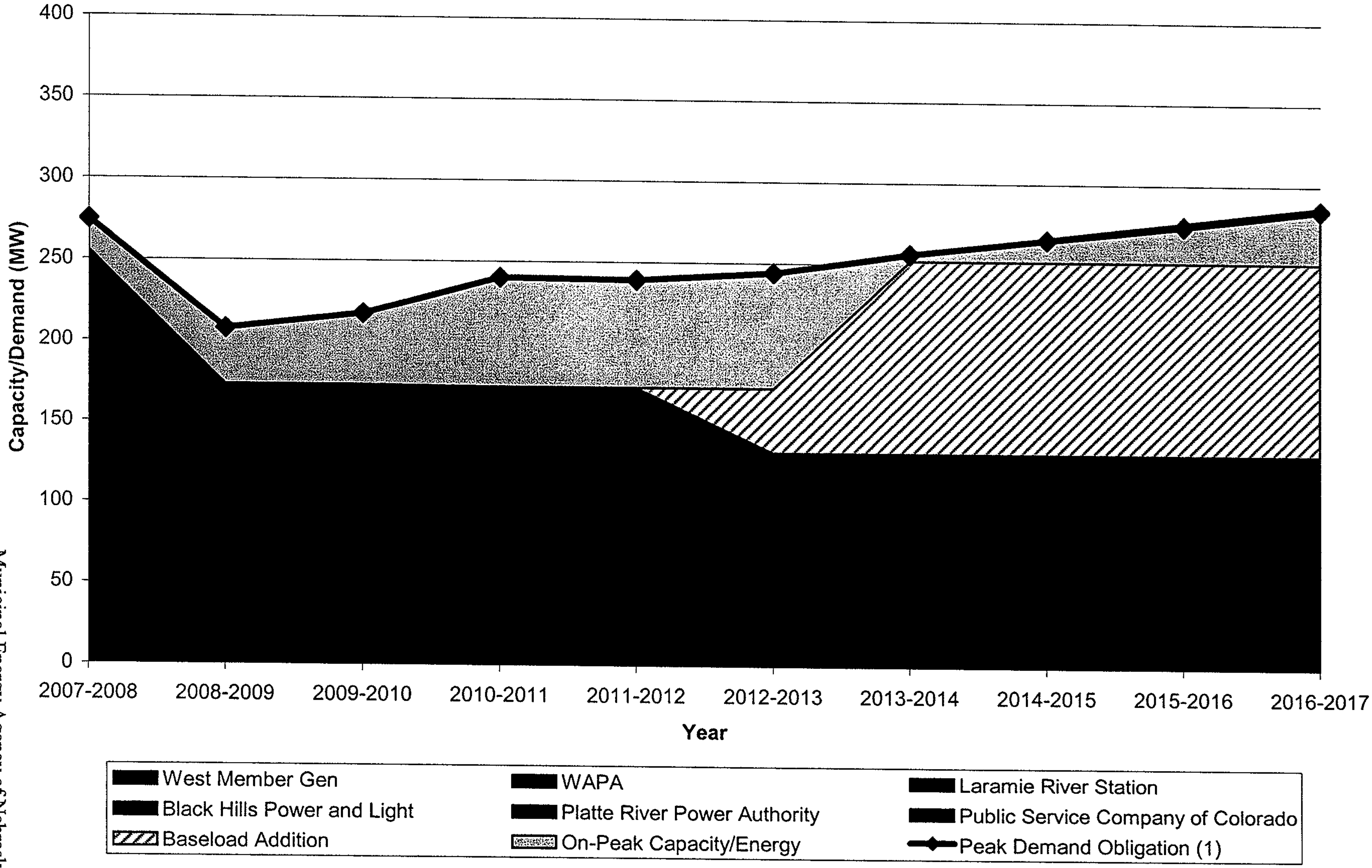
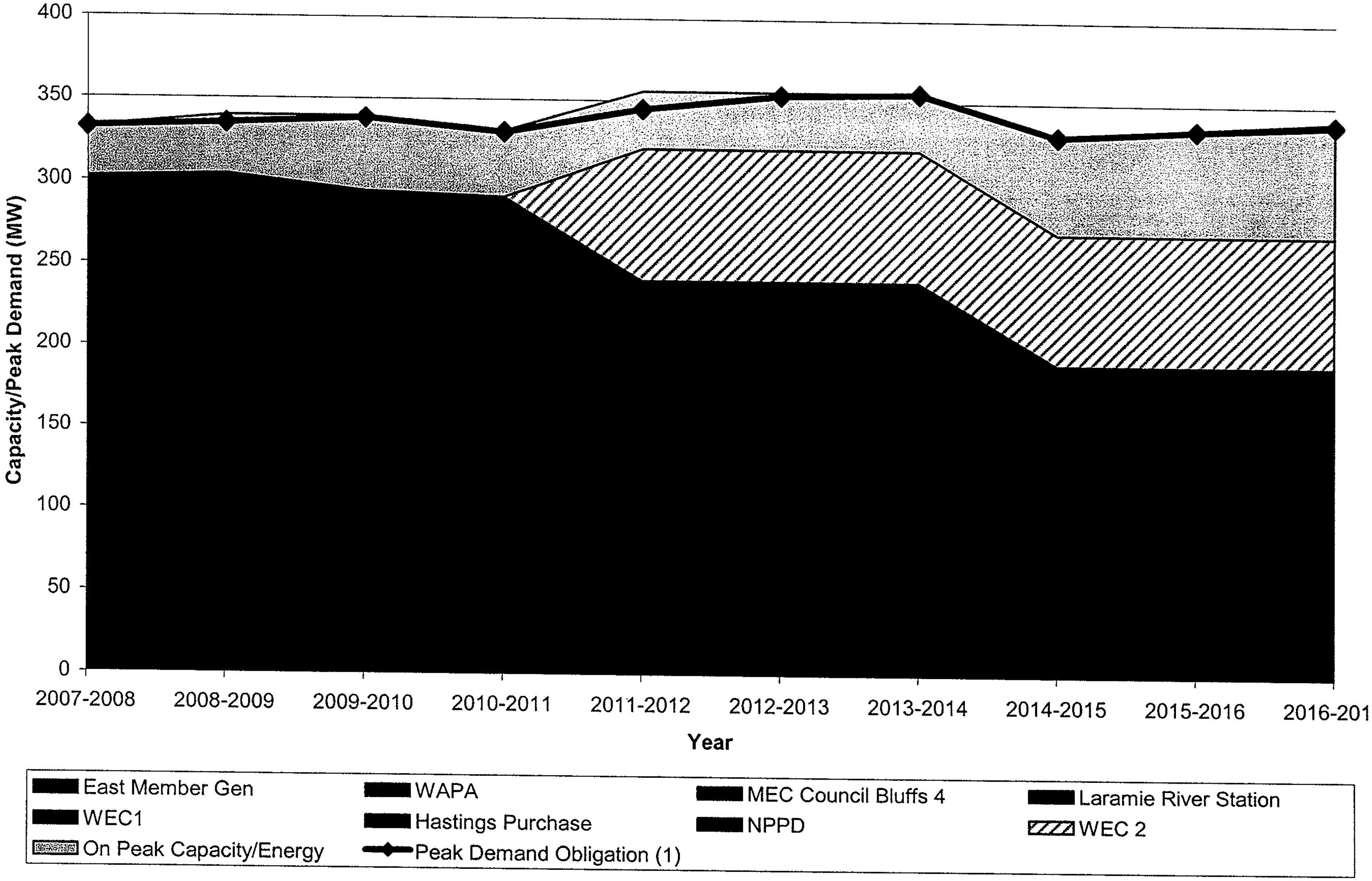


Figure 5 Resource Additions Recommended Integrated Resource Plan East Side



Section II. Introduction

Introduction

The IRP was developed to meet MEAN's resource requirements for the 10-year period beginning FY 2007-2008 through FY 2016-2017. MEAN's fiscal year begins April 1 and ends on March 31.

MEAN History

MEAN was created in 1981 under the Nebraska Municipal Cooperative Financing Act as a joint action agency and political subdivision of the State of Nebraska. Under the Act, MEAN may sell or exchange excess capacity of any project or electric power or energy owned by MEAN and not required by the participants. The Act authorizes MEAN to issue bonds, notes and other evidences of indebtedness. MEAN provides electricity and related services to 66 member communities, one public power district and one joint action agency in five states: Colorado, Iowa, Kansas, Nebraska, and Wyoming. As of July 31, 2007, 60 of the 68 members are Total Requirements Participants (TRP). The TRP purchase from MEAN all power supply requirements not provided by Western Area Power Administration (Western). The remaining eight members, who are not TRP, purchase energy from MEAN as needed.

The Management Committee is comprised of one representative from each member community that has signed the Electrical Resources Pooling Agreement (ERPA). Each member community has one vote on the issues that affect MEAN and its communities. Through participation on the MEAN Board of Directors, the members exercise control over rates, planning, operations and management.

Purpose

MEAN's purpose is to plan, acquire, finance and operate facilities to generate and transmit electric power and energy to its TRP. As part of MEAN's prudent planning effort and continuing commitment to its TRP, MEAN prepares and updates its IRP on an ongoing basis.

The purpose of this IRP is to develop long-range implementation plans to serve the TRP power supply requirements consistent with prudent utility planning practices.

Background

In November 1995, Western established a program called the Energy Planning and Management Program (EPAMP), which enables its customers to maintain their current allocations of capacity and energy from Western. EPAMP requires its customers to prepare and submit an IRP to Western every five years. This IRP is intended to meet the requirements of the EPAMP as well as be used as a planning document for MEAN.

Discussion of Past IRP Studies

MEAN submitted an IRP to Western in 2002. That IRP recommended MEAN purchase additional supply resources. MEAN implemented the recommendations of the 2002 IRP by purchasing capacity and energy from NPPD, PSCo and BHPL. MEAN also has a 6.67% ownership of Council Bluffs Energy Center 4 (CB 4) and will have 36.36% ownership of Whelan Energy Center 2 (WEC 2), both coal-fired baseload units. MEAN also increased its use of the Sidney AC/DC/AC tie capacity to take advantage of diversity between West Side and East Side loads and resources.

The 2002 IRP helped MEAN select the most cost-effective load shape objectives for the end-use customer, the TRP and MEAN. In addition to developing and implementing DSM programs, MEAN set up monitoring tools to compare DSM program benefits to costs. These monitoring tools help to provide justification for DSM program requests to the MEAN Power Supply Committee, the MEAN Services Committee and the MEAN Board of Directors and Management Committee.

Through the IRP process, MEAN and its member communities investigated, developed and implemented several DSM programs to enhance the supply-side resources. Updates to the IRP are submitted annually to Western.

Methodology

This IRP was prepared consistent with the EPAMP suggested methodology and is consistent with prior MEAN IRPs. The methodology used to prepare this IRP is summarized by the following list of tasks:

1. Prepared MEAN TRP peak demand and energy requirements forecast.
2. Compared forecasted peak demand and energy requirements to existing MEAN power supply resources to estimate future resource needs.
3. Screened power supply resource options to identify practicable resources to include in the integration analysis.
4. Screened DSM options to identify economical and technically feasible measures that could be included in the integration analysis.
5. Integrated DSM options with supply resources to develop IRP options.
6. Considered environmental impacts and costs of each IRP option.
7. Developed recommendation based on economic and non-economic considerations.
8. Identified measurement methods to describe whether IRP objectives are being met.
9. Solicited public participation and incorporated comments in the IRP.

General Objectives

MEAN's mission is to "provide long-term reliable and economical power supply resources and utility-related services to MEAN member communities." To achieve this stated mission, MEAN focused on the following objectives in developing the IRP:

- Remain a low cost energy provider.
- Ensure maximum flexibility in service, rates and pricing.
- Focus on being member-oriented.
- Maintain financial and rate stability.
- Encourage employee excellence.

Section III. Current MEAN System

Current Power Supply Arrangements

The MEAN system includes owned and purchased power supply resources, transmission system arrangements used to transmit MEAN's resources to the TRP, and DSM programs.

Existing Generating Resources

At the time this IRP was prepared, MEAN has more than 500 MW of power supply resources. MEAN has sold 30 MW of capacity and energy through April 2014. West Side and East Side resources are shown in Tables 9 and 10. (*Appendix A)*

Leased Generation

Twenty-seven (27) of MEAN's 60 TRP lease up to 135 MW of capacity to MEAN, twenty (20) MW of leased capacity is from the joint action agency, Arkansas River Power Authority (ARPA). The existing contract with ARPA to lease 20 MW of generation expires on September 30, 2007. All of the leased generation is fueled by natural gas and/or oil.

Black Hills Power & Light (BHPL)

MEAN has a long-term purchase power agreement with BHPL. The existing agreement expires February 21, 2013. Through this agreement, MEAN purchases 20 MW from Neil Simpson II and 20 MW from Wygen 1. Both plants are mine mouth coal-fired generation.

Council Bluffs Energy Center 4 (CB 4)

MEAN is a 6.67% (52.7 MW) owner of Council Bluffs Energy Center Unit 4 (CB 4) project. CB 4 is a 790 MW coal-fired supercritical steam-electric generating station located in Council Bluffs, IA. CB 4 went into commercial operation in June 2007. MEAN also has assignment of

0.40% (3.2 MW) ownership share through Waverly Light and Power (Iowa). Waverly assigned this ownership share to MEAN through February 1, 2010.

Hastings Utilities (HU)

HU provides up to 10 MW of system capacity and energy each hour. This agreement expires April 30, 2009.

Laramie River Station (LRS)

MEAN purchased 28 MW of entitlement in LRS from the Lincoln Electric System (LES). LRS is a three-unit, 1650 MW (550 MW each), coal-fired steam-electric generation station located on the Laramie River near Wheatland, WY. The three units at LRS began commercial operation in 1980, 1982, and 1982, respectively.

Nebraska Public Power District (NPPD)

MEAN purchases 100 MW of system participation from NPPD. Under this agreement, 60% of the energy is contingent upon Cooper Nuclear Station and 20% is contingent from each of the Gerald Gentleman Station 1 and 2 units. Either party has the right to reduce the contract rate of delivery (CROD) by 50 MW when WEC 2 is commercially available. This agreement expires April 30, 2014.

Platte River Power Authority (PRPA)

PRPA provides 10 MW of on-peak energy (HE 800-2300 MPT) Monday through Saturday, except in July and August when on-peak deliveries are zero. Off-peak energy delivered is 20 MW. This agreement expires December 31, 2007.

Public Service Company of Colorado (PSCo)

PSCo provides MEAN with 26 MW of firm capacity and energy service through September 30, 2007. PSCo will then provide MEAN with 25 MW of firm capacity and energy from October 1, 2007 through June 30, 2008.

Whelan Energy Center (WEC 1)

MEAN purchases from the City of Hastings 6.95% of the electric capacity and energy generated by the Whelan (formerly Hastings) Energy Center Unit 1 (WEC 1), a 77 MW coal-fired steam-electric generating station located near Hastings in Adams County, NE. This agreement terminates on the later of the date of the final maturity of the indebtedness incurred by Hastings to pay the costs of WEC 1, which is January 1, 2019, or the date Hastings removes WEC 1 or its associated transmission system in which MEAN participates from commercial operation.

Whelan Energy Center 2 (WEC2)

MEAN along with the cities of Grand Island, Nebraska City and Hastings, NE, and Heartland Consumers Power District (SD) formed the Public Power Generation Agency (PPGA) to finance a new 220 MW pulverized coal-fired generating unit near Hastings, NE. PPGA is the sole owner of the WEC 2 facility, which is expected to be completed in 2011. MEAN has a 36.36% participation share (80 MW) in WEC 2.

MEAN Wind Resource Pool

The MEAN wind resource pool consists of the Wind Project at Kimball, NPPD Ainsworth Wind Energy Facility and other renewable resources as approved by MEAN.
The MEAN Wind Project at Kimball, which is located three miles northwest of Kimball, NE, began commercial operation on October 1, 2002. The 10.5 MW nameplate wind project consists

of seven turbines. MEAN purchases of 7 MW from the 59.4 MW Ainsworth Wind Energy Facility. This participation power agreement ends October 1, 2025.

Western-Loveland Area Projects (Western-LAP)

Western delivers firm electric service to MEAN. MEAN acts as the agent for TRP with Western-LAP allocations. This agreement terminates at midnight on the last day of the September 2024 billing period. MEAN provides scheduling and transmission of all monthly energy, support energy, and pumped storage energy that the TRP is entitled to under its Western agreement.

Western-LAP Capacity and Energy Displacement

MEAN and Western exchange and transmit power and energy for mutual benefit. MEAN exchanges and transmits power and energy generated or acquired in the States of Nebraska and Kansas for power and energy generated by Western's LAP to serve MEAN's customers in the western interconnection. Western exchanges and transmits power and energy generated by LAP resources in the western interconnection for power and energy generated or acquired by MEAN in the states of Kansas and Nebraska to serve Western's customers in the states of Kansas and Nebraska. The monthly maximum capacity displacement is approximately 34 MW in the month of July. This agreement terminates at midnight on the last day of the September 2024 billing period.

Western-Salt Lake City Area (Western-SLCA)

Western delivers firm electric service to MEAN. MEAN acts as the agent for TRP with Western-SLCA allocations. This agreement terminates at midnight on the last day of the September 2024 billing period. MEAN provides scheduling and transmission of all monthly energy, including Available Hydro Power (AHP), Customer Displacement Power (CDP), and Western Replacement Power (WRP) that the TRP is entitled to under its Western agreement.

Western-Upper Great Plains (Western-UGP)

Western-UGP currently provides approximately 22 MW firm capacity and energy to meet MEAN load requirements. This contract expires in September 2024.

Future Power Supply Resources

MEAN participates in a statewide joint-planning effort through the Nebraska Power Association (NPA). NPA is a utility organization made up of MEAN, LES, Omaha Public Power District (OPPD), NPPD, municipal utilities, and rural public power districts in Nebraska. Utilities in NPA jointly plan long-term power supply facilities to meet the electric power needs of the State of Nebraska. MEAN actively participates in NPA's resource planning process.

Transmission

MEAN's TRP are served by eight transmission providers:

1. BHPL provides network firm and ancillary services for Gillette, WY. BHPL also provides firm point-to-point service for off-system sales. This agreement is in place through March 2011.
2. CSU provides network firm and ancillary services for Fountain, CO. This agreement expires June 30, 2010.
3. MEC provides network firm and ancillary services to seven TRP in Iowa. MEC also provides 50 MW of point-to-point service for delivery of CB 4 capacity to the NPPD system.
4. NPPD provides network firm and ancillary services to 30 TRP in Nebraska. NPPD also provides firm point-to-point service for off-system sales as well as non-firm use to alternate points and non-firm point-to-point service for economy sales to MEAN Service Power participants and other utilities. This agreement expires December 31, 2015.

5. The transmission service agreement between PSCo and MEAN, PSCo provides network integration transmission service under its pro forma Open Access Transmission Tariff for delivery of power and associated energy to the cities of Aspen and Glenwood Springs, CO.
6. MEAN has a network integration transmission agreement with Tri-State G&T that is used to provide the City of Delta, CO with wheeling and ancillary services. Tri-State also provides the City of Sidney, NE, 7 MW of firm transmission rights. These agreements are under the Tri-State pro forma Open Access Transmission Tariff.
7. Western-LAP provides network transmission service on the LAP transmission system. Western also agrees to provide non-firm transmission service to MEAN to the extent excess transmission capacity is available on the LAP transmission system. This contract continues through March 31, 2009.
8. Western-SLCA provides network transmission service on the Salt Lake City Integrated Projects transmission system for delivery of power and energy to the City of Gunnison, CO, and the Town of Oak Creek, CO. This contract expires on September 30, 2012.

In addition, the agreements for the purchase of capacity and energy from LRS, WEC 1 and CB 4 include acquisition of proportionate transmission rights in the transmission facilities associated with LRS, WEC 1 and CB 4, respectively.

MEAN Load Shape

The hourly demand profile for MEAN is shown in Figures 6 and 7 (*Appendix B*). The profile was prepared separately for the West Side and East Side and normalized on the basis of the annual peak. The demand profile was used to select load shape objectives.

Current DSM Activities

Based on the findings of previous IRPs, MEAN and its TRP implemented several DSM programs:

- Appliance Installations – In 1997, MEAN implemented the Retail Energy Assistance Program (REAP) to encourage strategic load growth. REAP provided rebates to customers that purchased electric appliances, such as heat pumps with high efficiency ratings, and electric water heaters. Between 2002 and 2007, REAP was used by end-use customers to save approximately 4.4 MW of load, and over $286,000 was paid through REAP. Because increased costs of competing fuels made installation of efficient electric appliances cost-effective without rebates, REAP was discontinued on March 31, 2007.

- Direct Load Control (DLC) Installations – The MEAN TRP use DLC to reduce peak contributions from air conditioners, water heaters, irrigation pumps, municipal water pumps, and industrial interruptible loads.
- Indirect/Social Load Control Activity – Many MEAN communities have implemented indirect and social load control systems. When the utility is approaching its peak demand, customers are encouraged to reduce loads voluntarily. The utility informs its customers of an approaching peak demand situation through different methods, such as radio broadcasts, cable television appeals, by blowing the fire whistle, or using the sign at the local civic center.

Section IV. Load Forecast

Introduction

A load forecast was prepared to project TRP peak demand and energy requirements for the period FY 2007-2008 through FY 2016-2017. The forecast incorporated econometric forecasting methods to relate historical energy consumption to economic and population growth, employment, real per capita income, number of customers, heating and cooling degree days, and the real wholesale and retail price of electricity. Subsequently, the relationships were applied to projected econometric variables to project future energy consumption.

Forecast Methodology

The TRP were separated into 18 groups, as displayed in Table 11 (*Appendix A*). The groups were selected based on geographic proximity and similarity of load characteristics. Annual and seasonal forecasts for each of the 18 groups were developed through the use of econometric models. A model was developed for each group by selecting factors that may have influenced energy requirements in the past and may likely influence the TRP future energy use.

- Econometrics – The study considered econometric data to explain historical energy consumption. Historical and projected economic factors that influence the TRP load included population, employment, number of customers, real per capita income, and the real wholesale and retail price of electricity. The factors that influenced energy usage varied by group. The influencing factors for each group were used to estimate future energy requirements. To the extent that actual trends deviate from the projections used in this forecast, actual peak demands and energy usage should deviate from these projections.
- Weather – The effect of weather on energy usage was also considered. For each group, heating and cooling degree days were collected from a nearby weather station. The degree days were used to evaluate the effect of weather on energy requirements.

Degree days were an influencing factor on several individual participants; however, only 3 of the 18 groups displayed a direct relationship to degree days.

Load Forecasting

The load forecast is summarized in Tables 12 and 13 (*Appendix A*), and shown graphically in Figures 8 and 9 (*Appendix B*). The West Side forecasts include serving ARPA until May 2008. West Side peak demand growth was forecasted at an average annual compound rate of 3.0% for the period FY 2009-2010 through FY 2016-2017. West Side winter peak demand was forecasted to increase from approximately 239 MW in FY 2008-2009 to approximately 295 MW in FY 2016-2017. West Side summer peak demand was forecasted to increase from 259 MW in FY 2008-2009 to approximately 328 MW in FY 2016-2017.

East Side peak demand growth was forecasted at an average annual compound rate of 1.6% for the period FY 2008-2009 through FY 2016-2017. East Side winter peak demand was forecasted to increase from approximately 183 MW in FY 2008-2009 to approximately 207 MW in FY 2016-2017. East Side summer peak demand was forecasted to increase from 203 MW in FY 2008-2009 to approximately 230 MW in FY 2016-2017.

The energy requirements forecast is summarized in Figures 10 and 11 (*Appendix A*). The average annual compound rate for energy requirements was 3.1% for the West Side and 1.5% for the East Side for the period FY 2008-2009 through FY 2016-2017. West Side winter energy requirements were forecasted to increase from approximately 993,000 MWh in FY 2008-2009 to approximately 1,215,000 MWh in FY 2016-2017. West Side summer energy requirements were forecasted to increase from approximately 463,000 MWh in FY 2008-2009 to approximately 591,000 MWh in FY 2016-2017. East Side winter energy requirements were forecasted to increase from approximately 653,000 MWh in FY 2008-2009 to approximately 736,000 MWh in FY 2016-2017. East Side summer energy requirements were forecasted to increase from approximately 366,000 MWh in FY 2008-2009 to approximately 412,000 MWh in FY 2016-2017.

A severe weather scenario was developed for the peak demand forecast. It was calculated by looking at the most extreme weather that occurred in the last 20 years and the lowest capacity factor that MEAN has experienced. Based on this methodology, it was estimated that a severe weather scenario would have a peak demand of approximately 12% higher than the normal weather case on the West Side and approximately 5% higher on the East Side than the normal weather case, as shown in Figures 12 and 13, respectively (*Appendix B*).

Comparison of Peak Demand and Energy Requirements to Resources

Forecasted peak demand and energy requirements were summarized and compared to existing capacity and energy resources. Tables 14 and 15 summarize the Comparison of Peak Demand and Energy Requirements to Resources for the West Side and East Side, respectively (*Appendix A*). MEAN's peak demand obligation includes peak demand and capacity reserves. Capacity reserves were calculated using the MAPP reserve requirement of 15% of peak demand. The 15% reserve was not applied to firm resources such as WAPA allocations. Based on the Comparison of Peak Demand and Energy Requirements to Resources, the following was concluded:

- MEAN is capacity deficit on the West Side by approximately 40 MW in FY 2007-2008, not including Sidney AC/DC/AC tie transfers. The capacity deficit increases to approximately 193 MW in FY 2016-2017.
- MEAN is energy deficit on the West Side by approximately 363,000 MWh in FY 2007-2008, not including Sidney AC/DC/AC tie transfers. The energy deficit increases to approximately 1,245,000 MWh in FY 2016-2017.
- The capacity factor of the West Side demand and energy requirements indicates that MEAN resource needs are intermediate to baseload in nature.

- MEAN is capacity deficit on the East Side for the periods of FY 2009-2011 and FY 2014-2017. The maximum deficit is 28 MW in FY 2016-2017.
- MEAN is energy surplus on the East Side by approximately 422,943 MWh in FY 2007-2008. The energy surplus decreases to 150,313 MWh in FY 2016-2017.
- The East Side demand requirements and energy surplus indicates that MEAN resource needs are peaking in nature.

The capacity factor derived from the balance of load and resources indicates that MEAN needs to acquire resources that would provide baseload to intermediate energy on the West Side and peaking capacity on the East Side. The existing peaking generation owned and operated by MEAN TRP can generate energy, but typically are not used extensively because the cost of energy in the market is much less than the cost of energy from the owned resources. Also, emissions permits limit the number of hours many of the units can operate on an annual basis.

Section V. Supply-Side Resource Evaluation

Introduction

The EPAMP indicates the IRP should consider all practicable energy supply resource options. The resource options considered in this IRP included generic options as well as options currently available in Nebraska and the surrounding region. The resources were screened and evaluated for inclusion in MEAN's IRP.

Identification of Resource Options

Several power supply resource alternatives were considered to meet MEAN's resource needs. The alternatives are described below along with how each alternative can be incorporated in MEAN's system.

- Owned and Leased Generation including Unit Participation Purchases – Leasing additional diesel generation units at the existing plant sites could meet capacity requirements on the East Side. The energy generated would be fueled by natural gas or oil and would cost more to generate than purchasing from a utility with excess coal-fired capacity. MEAN could also construct another coal-fired facility to meet baseload capacity and energy requirements. Baseload facilities that are considered economical typically are sized in the 200-400 MW range. This amount of capacity would be considerably more than MEAN needs; however, MEAN could participate in such facilities with other utilities. Another option for MEAN is to construct or participate in a natural gas-fired combined-cycle generating facility as an intermediate resource. Wind, small hydro and other renewable resources are considered to reduce environmental impacts, but do not meet capacity requirements. Life-of-unit participation in generating facilities of other utilities or Independent Power Producers (IPP) is a practical option if the proper amount of capacity can be purchased at an economical price. The life of a baseload coal-fired plant is typically 30-40 years, therefore, this option would be a long-term resource. An example of this type of purchase would be ownership of CB 4, which began operation in June 2007. The following owned and leased generation options were considered:

- West Side Options
  a. Coal-fired baseload 40 MW unit ownership in Wyoming
  b. East Side baseload unit and expansion of the Sidney AC/DC/AC Tie
  c. Proposed hydroelectric and pumped storage facility in Colorado
  d. Proposed waste coal-fired unit in Wyoming
- East Side Options
  a. Proposed baseload coal-fired units in Iowa
  b. Proposed compressed air storage and natural gas fired unit in Iowa

- Purchase Power Contracts – Purchasing power and energy from other utilities or power marketers is also an option because several area utilities are interested in marketing surplus capacity and energy; however, many utilities have been unwilling to commit to long-term agreements to sell capacity and energy. This is caused by increasing volatility in the wholesale electric market, fuel cost volatility, transmission availability, and credit risk concerns. Purchase power contracts considered:
  - West Side Options
    a. On-peak capacity and energy purchases
    b. Short-term natural gas-fired combined cycle participation in Colorado (2010-2013)
  - East Side Options
    a. Short-term peaking capacity purchases
- Renewable Energy Purchase Power Contracts – Existing MEAN renewable resources are not sufficient to supply current participant requests. MEAN will also monitor applicability of requirements set forth in future renewable energy standards such as national or state level Renewable Energy Portfolio Standards (RPS). Regardless of regulatory obligations, MEAN will add practicable renewable resources that benefit the TRP as they become available. Purchase power contracts considered:
  - Purchase power agreements for wind energy to serve member requests in Colorado, Nebraska, Iowa South Dakota and Wyoming

Screening Assessment

The purpose of the screening assessment is to identify resources that meet MEAN's needs and to eliminate technically infeasible and uneconomical resources from the detailed IRP analysis. It is simply a first step in the evaluation process.

Evaluation Criteria

MEAN established several evaluation criteria for the power supply resources, including:

- Ability to meet MEAN's resource needs.
- Reliability and availability of the resources.
- Operational flexibility of the resource including ramp rates and scheduling provisions.
- Environmental impacts and compliance costs.
- Total delivered cost of the resource.

Supply-Side Resource Screening

The cost of each supply-side resource was calculated at capacity factors ranging from 0-95% in 2012 dollars. The total costs for each resource were compared. The screening analysis for intermediate to baseload resources is shown in Figure 14 (*Appendix B*). The screening analysis for peaking to intermediate is shown in Figure 15 (*Appendix B*). The analyses show that coal-fired and natural gas combined cycle units are the lowest cost resources that MEAN can acquire.

Section VI. Demand Side Management Analysis

Introduction

DSM options were considered as a method of deferring capacity resource acquisitions. DSM options modify the customer or end-use load shape. New DSM options were considered, as was broadening of existing DSM programs offered through MEAN.

Review of Load Shape Objectives

The Electric Power Research Industry (EPRI) developed six industry accepted load shape objectives, which are used to meet certain operational objectives. DSM options are classified by the load shape objectives fulfilled by the activity. The objectives (in italic) are as follows:

- *Strategic Load Growth* involves the encouragement of increased loads in all hours for utilities with surplus capacity for all periods of the year. Sample programs include incentives to install energy-efficient technologies or more electric-intensive technologies, or through fuel switching.
- *Peak Clipping* is the reduction of system peak loads, thus reducing the need to operate peaking units with high fuel costs. An example of a peak clipping program is a load management system that cycles air conditioners.
- *Strategic Conservation* is an objective directed at reducing end-use consumption. Strategic conservation will help TRP retail customers conserve energy and environmental resources. Strategic conservation may have minimal effect on peak load. Examples of strategic conservation include compact fluorescent bulb or appliance efficiency programs.
- *Valley Filling* is a form of load management that increases or builds off-peak loads. Security lighting is an example of an end-use that may help increase evening loads, which are typically off-peak.

- *Load Shifting* involves shifting load from on-peak to off-peak periods. An example of load shifting technology is ceramic heat storage.
- *Flexible Load Shape* involves using DSM technologies to modify the load shape on short notice to meet demand requirements without shifting or clipping load during periods when it is not required.

DSM options that satisfy these load shape objectives were selected for further evaluation.

MEAN selected three primary load shape objectives from the six listed above:

1. Peak Clipping
2. Strategic Conservation
3. Valley Filling

Screening Analysis

The screening analysis consisted of two steps – qualitative screening and economic feasibility. Qualitative screening ranked the potential DSM options according to subjective criteria, such as customer preference, market potential and ease of implementation. A score was assigned to each DSM option and the options were ranked. This narrowed the list of options to be economically further evaluated. The DSM options were then evaluated for economic feasibility. The avoided costs for capacity and energy calculated in the supply-side resource evaluation were used to calculate the costs and benefits of each DSM option.

Much of the DSM screening utilized information from the Western Resource Planning Guide (RPG), which provided a process for evaluating DSM options and provided reference data for use in the economic evaluation of DSM options.

1. Qualitative Screening – The DSM options that satisfy MEAN's load shape objectives were subjected to a qualitative screening. The screening involved the use of six criteria called "second tier criteria" to identify those technologies most relevant to MEAN's objectives. According to RPG, the second tier criteria are:
   a. *Costs*. This includes start-up, marketing and equipment costs.

b. *Customer Preferences*. Factors to consider when determining customer's acceptance of a technology are the willingness to use the measures, the change in comfort levels and the customer's cost effectiveness for the measure.
c. *Environmental Impacts*. DSM options can postpone supply-side resources that may have emissions into the environment; however, there are also environmental impacts associated with some DSM options. Hazardous waste disposal will be an issue when disposing of old refrigerator compressors containing chlorofluorocarbons (CFCs) and old ballasts with polychlorinated biphenyls (PCBs). Another example is disposal of compact fluorescent bulbs with ballasts containing mercury.
d. *Market Potential*. Target markets and end-uses must be reviewed to identify those options that may result in the greatest potential impact.
e. *Ease of Implementation*. The relative ease of implementing the program will be associated with its success. Some options may require major design changes in the building structure or HVAC system while others may only involve replacement of lights and appliances.
f. *Availability*. The DSM option must be commercially available and reliable.

All options were scored from 0 to 3 according to their ability to satisfy each of the preceding criteria. The scores for each option were summed for a combined total. Those options with higher total scores were considered to be more successful in achieving MEAN's load shape objectives than those with lower scores. The scores for each option are shown by customer class in Tables 16 and 17 (*Appendix A*).

The options that passed the qualitative screening included eleven residential options and five commercial options. This pre-screening only used qualitative factors to narrow the list of options that would be further evaluated.

2. Economic Evaluation – The 16 options were then subjected to an economic evaluation. The projected annual cost for each option was compared to the projected

power cost savings to calculate the net present value of the cost or savings of each option. The following assumptions were used in the economic evaluation:

a. The evaluation was done on a "per unit" basis, meaning the analysis evaluated one installation of the given option.
b. Technical information for the options was based on past experience, when possible. When information from past experience was not available, the RPG Reference Data for the Southern Region was used.
c. Avoided demand and energy costs from the supply-side resource evaluation were used. It was assumed that peak demand savings were used to reduce seasonal capacity purchases, with the summer season being defined as June-September and the winter season as October-May.
d. End-use information was taken from the 2005 Energy Information Agency (EIA) Form 861 data.
e. A discount rate of 5% was used.
f. The Total Resource Cost (TRC) test was used. This compared the total costs of the option, whether incurred by MEAN, the TRP or the end-user to the total cost savings realized by MEAN.

Using these assumptions, the 16 DSM options were evaluated over a 10-year study period. The evaluation considered all of the installation, operation and maintenance, and administrative and general expenses that would be incurred over the 10-year period. The expenses were compared to MEAN's avoided capacity and energy cost. The net cost or savings to MEAN was calculated on an annual basis and discounted to 2007 dollars. Options with a positive net present value (indicating savings) were considered economically feasible. A summary of the economic evaluations is shown in Table 18 (*Appendix A*). The analysis of each individual DSM option is shown in Appendix C.

Three of the options have a positive net present value over the 10-year study period:

- Interruptible Rates
- Compact fluorescent lighting
- Commercial high-efficiency lighting

The most economical and highest ranking residential option was Compact Fluorescent Lighting. MEAN plans to investigate a program to offer rebates to offset the difference in price between incandescent and compact fluorescent bulbs. Such a program would also encourage the proper disposal of the compact fluorescent bulbs at the end of bulb service life.

The most economical commercial options were interruptible rates and commercial high-efficiency lighting. The economical commercial options received a similar high ranking among potential commercial programs. MEAN supports interruptible rates through financial assistance to members that conduct a COS/RDS which can identify interruptible rate options when feasible. MEAN's rates, through demand charges and ratchets, also provide a rate signal to the TRP to implement interruptible rates where practicable. MEAN plans to investigate a program that encourages commercial high-efficiency lighting in conjunction with energy audits already offered to commercial and industrial customers. The program would offer rebates and other assistance to end-use customers who install high-efficiency lighting.

Many DSM options applicable to the industrial sector are site-specific. MEAN provides energy audits for its TRP through the commercial/industrial energy audit program. These audits provide site-specific information needed to evaluate industrial sector DSM technologies.

Based on the evaluation, MEAN and its TRP will continue to use existing DSM programs, except for the REAP program. There is little incremental cost to these measures and there has been significant investment in these programs.

There are some DSM options that can be implemented for little or no cost. MEAN will continue to evaluate and consider low cost DSM options, such as promoting energy efficiency via the NMPP Energy web site and customer fliers.

Section VII. Development of Preferred Plan

Introduction

Based on the supply and demand side analysis, the most practicable and feasible plan was developed. Non-economic factors, such as scheduling and transmission access, were also considered in developing the preferred plan. Since the DSM options that were considered feasible had no quantifiable reduction in capacity requirements nor reductions in short-term energy requirements, the preferred plan only considered existing DSM and did not include new programs. Practicable supply resources were combined to develop East Side and West Side cases.

MEAN developed resource screening curves in Figures 14 and 15 (*Appendix B*) and hourly deterministic models used to determine monthly production requirements for various resource expansion plans. The hourly deterministic models calculated annual production requirements based on the existing load forecast and 2006 hourly load data for FY 2011-2012 and FY 2016-2017.

The following assumptions were used in the evaluation:

- Existing resource contracts were allowed to expire at the end of the original term.
- Resource additions in 5 MW increments were assumed.
- No retirements of existing TRPs generation were assumed with exception of ARPA leased generation that was not included beyond September 2007.
- Sufficient capacity was planned to serve East Side and West Side by using the Sidney AC/DC/AC tie and WAPA Displacement agreement.

Several cases were evaluated using resource screening curves and the hourly deterministic models. The resource screening curves were used to evaluate the most feasible resource cases.

West Side Comparison

Several West Side cases were developed. Since there are few resources being contemplated, each of these cases involved purchasing capacity and energy in the near-term from other utilities and participating in ownership of additional baseload to intermediate generation in the FY 2013-2014 timeframe. MEAN will continue to work to identify other suppliers and resources that would be available to MEAN during the next five years.

- Case 1 - This case involved purchasing on-peak capacity and energy as needed from other utilities. Case 1 is subject to market price volatility and the availability of resources to purchase. Case 1 is practicable resource option only if other resources are not feasible.
- Case 2 - This case involved expansion of the Sidney AC/DC/AC Tie. MEAN would acquire 125 MW of additional capacity to transfer energy to the West Side. This case depends on future resource availability and production costs on the East Side. The additional tie capacity would also offer the option of purchasing West Side capacity and energy in the East, but the economical advantage is difficult to predict. If baseload resources in the East are cheaper than similar resources in the West, then expanding the Sidney AC/DC/AC tie capacity would be a feasible option.
- Case 3 - This case involved 120 MW unit participation of a proposed waste coal-fired steam plant for commercial operation in FY 2013-2014 and on-peak capacity and energy purchases for remaining MEAN resource needs. Case 3 is less subject to market price volatility and lack of availability to purchase energy from other utilities beyond FY 2013-2014 than Case 1 when the waste coal-fired unit is in operation.

The outage schedule with waste coal-fired steam is not known, but 85% capacity factor is anticipated. Outages were projected to be in low usage months of either April or October. Available transmission across the TOT 3 transmission constraint from Wyoming to Colorado is a concern. However, the lack of proposals for additional coal-fired baseload plants being built on the West Side makes the proposed waste coal-fired unit a feasible resource.

- Case 4 - This case involves ownership of 40 MW of coal-fired generation in Wyoming in FY 2012-2013, short-term participation in a 68 MW combined cycle natural gas unit for FY 2010-2011 through FY 2012-2013, 80 MW unit participation of a proposed waste coal-fired steam plant for commercial operation in FY 2013-2014 and on-peak capacity and energy purchases for remaining MEAN resource needs. Coal-fired generation is lowest cost baseload resource available. Access to transmission and minimal transmission investment from the 40 MW ownership share of the Wyoming facility makes that resource a feasible option. Case 4 is less subject to market price volatility and ability to purchase energy than other West Side cases for FY 2010-2011 through FY 2012-2013 when the combined cycle natural gas unit is available for MEAN to purchase than in Case 1 and Case 3; however, natural gas price fluctuations will affect production costs. The combined cycle natural gas unit is a feasible resource option dependent upon market energy prices, the ability to hedge natural gas prices, and if other more feasible resources become available. Case 4 is less subject to market price volatility and ability to purchase energy from other utilities beyond FY 2013-2014 than Case 1 when the waste coal-fired unit is in operation. By participating in 80 MW, instead of 120 MW as in Case 3, operational and transmission related challenges of the proposed waste coal-fired unit mentioned in Case 3 are minimized.

East Side Comparison

- Case 1 - This case involved purchasing 30 MW of short-term capacity in the MRO region as well as purchasing additional 10-40 MW of on-peak capacity and energy for remaining resource needs.

Other Considerations

There were numerous other considerations in developing this IRP. Some of the more important items, described below, relate to schedule and risk mitigation.

Schedule

One of the key considerations in the development of the preferred plan is the schedule. In general, generating plants have lead times for construction of anywhere from 2-10 years. Coal-fired, baseload units, in particular, can take 7-10 years from initial planning to commercial operation. In addition, for a utility the size of MEAN, it is impractical to develop a large, baseload project without other participants.

A fully subscribed project offers several advantages over other baseload resources that may be considered. Many key critical path items can be completed, such as environmental permitting, transmission studies, contract development, site development and other regulatory approvals, so a project completion date can be established in order to determine if the resource needs of MEAN will be met in a given timeframe.

There are, however, several reasons why a project would not be built. For example, a major owner could have the right to terminate the project. Also, rejection of a siting application or air permit application could delay or prevent construction of a plant.

One of the options considered, the Iowa Joint Action Agency, is a project positioned in terms of critical path items for a 2014 start date. However, the commitments from other project participants are only in "Phase I," which includes permitting, conceptual design, and preliminary transmission studies. Each participant will make a decision at the conclusion of Phase I to continue to participate in the project. At this point, it is unclear if other participants are planning to continue to participate in the project.

Risk Mitigation

MEAN has developed a risk management policy that plays a crucial role in its planning processes. The goal is to minimize "unmitigated risk" and set limits in terms of how much unmitigated risk MEAN is able to accept. In general, MEAN ensures it has adequate resources to serve its needs, but no more than it needs to serve its requirements reliably and economically. For example, MEAN would not take a speculative position for the express purpose of taking advantage of a change in market prices. The positions MEAN takes generally are for the purpose of serving load and providing for contingencies.

In applying this policy to long-term planning, MEAN plans to have sufficient capacity to meet long-term needs. MEAN would not add capacity in excess of its forecasted loads unless it is economically feasible to do so. In addition, MEAN would not plan to be short of capacity in a given period, particularly in the near-term planning horizon (less than two years) because this would represent a potential unmitigated risk.

Summary

Tables 19 and 20 (*Appendix A*) summarize the preferred plan of West Side Case 4 and East Side Case 1. While the practicable cases varied economically, the development of the preferred plan involved other, non-economic factors. The expansion plan is shown graphically for the West Side and East Side in Figure 15 and Figure 16, respectively (*Appendix B*).

Environmental Impacts

MEAN considered environmental impacts in developing its IRP. Proposed projects will include Best Available Control Technology (BACT) to help reduce environmental impacts. MEAN did not include environmental externalities in the economic screening of resource alternatives. The MEAN Wind Resource Pool is an example of projects that will help minimize environmental impacts. The projects do not emit regulated pollutants and greenhouse gases. MEAN will continue to investigate future renewable resources.

Section VIII. Conclusions and Recommendations

Conclusions

Based on the assumptions used and analyses completed, the following was concluded:

1. MEAN is capacity deficit on the West Side by approximately 40 MW in FY 2007-2008, not including Sidney AC/DC/AC tie transfers. The capacity deficit increases to approximately 193 MW in FY 2016-2017.
2. MEAN is energy deficit on the West Side by approximately 363,000 MWh in FY 2007-2008, not including Sidney AC/DC/AC tie transfers. The energy deficit increases to approximately 1,245,000 MWh in FY 2016-2017.
3. The capacity factor of the West Side demand and energy requirements indicates that MEAN resource needs are intermediate to baseload in nature.
4. MEAN is capacity deficit on the East Side for the periods of FY 2009-2011 and FY 2014-2017. The maximum deficit is 28 MW in FY 2016-2017.
5. MEAN is energy surplus on the East Side by approximately 422,943 MWh in FY 2007-2008. The energy surplus decreases to 150,313 MWh in FY 2016-2017.
6. The East Side demand requirements and energy surplus indicates that MEAN resource needs are peaking in nature.
7. Purchasing capacity and participating in new generating units were considered.
8. The feasible West Side resource options during the 10-year study period include:
    a. Coal-fired baseload 40 MW unit ownership in Wyoming
    b. East Side coal-fired baseload unit and expansion of the Sidney AC/DC/AC Tie
    c. On-peak capacity and energy purchases
    d. Proposed waste coal-fired unit in Wyoming
    e. Short-term natural gas combined cycle participation in Colorado (2010-2013)
    f. Wind resource proposals in Colorado and Western Nebraska
9. The feasible East Side resource options during the 10-year study period include:
    a. Short-term peaking capacity purchases
    b. Wind resource proposals in Iowa, Nebraska, and South Dakota

10. DSM options that resulted in net benefits to the TRP included the implementation of interruptible rates as well as the installation of compact fluorescent bulbs and high efficiency commercial lighting.

Recommendations/Action Plan

Based on the assumptions used, analyses completed and conclusions reached, the following IRP is recommended. The recommended resource additions are shown in Tables 19 and 20 for the West Side and East Side, respectively (*Appendix A*). The integration of the resource additions with MEAN existing resources are shown in Figures 15 and 16 (*Appendix B*).

- West Side
  - Continue to explore other practicable supply options
  - Investigate combined cycle natural gas-fired unit participation
  - Investigate additional West Side baseload generation
    - East Side baseload and Sidney AC/DC/AC Tie expansion
    - West Side baseload units
  - On-peak capacity and energy purchases
  - Purchase power agreements for wind energy to meet TRP requests
- East Side
  - Continue to explore other practicable supply options
  - Purchase power agreements for wind energy to meet TRP requests
  - Short-term peaking capacity purchases
- Investigate DSM programs involving compact fluorescent bulbs and high efficiency commercial lighting.

Public Participation

Part of the IRP implementation process involves public participation. MEAN has involved the public in developing the IRP, and will continue to solicit public participation as it implements the IRP.

The IRP was presented at a public hearing held in North Platte, NE, on August 16, 2007. The purpose of this hearing is to provide information to and gather input from groups and individuals with an interest in MEAN's Integrated Resource Plan. A notice of a public hearing appeared in the Lincoln Journal Star newspaper.

Measurement Strategies

MEAN compares its load forecasts to actual usage on an annual and monthly basis. This comparison will be continually updated in the future. In addition, MEAN will continue to verify the effectiveness of DSM programs in its annual updates to this IRP.

Annual Updates

Annual updates to this IRP will be prepared. The annual updates will provide comparisons of actual and projected DSM activity and planned changes in power supply resources or DSM programs. The updates will also identify changes to the IRP. Changes to the IRP may be caused by load changes or changes in resources or DSM programs.

Table 9
West Side
Existing and Committed Generation Resource

Generation Facility	Resource	Capacity (MW)	Expiration	Primary Energy Source
Bulk Power Participants	Facilities Committed under Pooling Agreements	45.1	None	Oil/Natural Gas
WAPA	Firm Electric Service	116.5	September 2024	Hydroelectric
Black Hills Power and Light (1)	Neil Simpon 2 and Wygen 1	40.0	February 2013	Coal
Lincoln Electric System	Laramie River Station Units 2 and 3	18.0	Life of plant	Coal
Platte River Power Authority (2)	System Participation	10.0	December 2007	Coal
Public Service Company of Colorado	Purchase Power	26.0	September 2007	Purchase
Short Term Purchases	Purchase Power	20.0	August 2007	Purchase
MEAN Wind Project at Kimball	Renewable Intermittent Resource (Wind)	0.0	Life of plant	10.5 MW Nameplate Wind
West Subtotal		**275.6**		

1. Expires February 2013, Conversion to permanent ownership is being negotiated
2. Expires December 31, 2007, Contract extension to December 2008 is being negotiated

Table 10
East Side
Existing and Committed Generation Resource

Generation Facility	Resource	Capacity (MW)	Expiration	Primary Energy Source
Bulk Power Participants	Facilities Committed under Pooling Agreements	90.0	None	Oil/Natural Gas
WAPA	Firm Electric Service	31.4	September 2024	Hydroelectric
NPPD [1]	Cooper Nuclear Station	60.0	April 2014	Nuclear
NPPD [2]	Gerald Gentleman Station	40.0	April 2014	Coal
Lincoln Electric System	Laramie River Station Unit 1	10.0	Life of plant	Coal
Hastings, NE	System Participation	10.0	April 2009	Coal/Natural Gas
Hastings, NE	Hastings Energy Center	5.0	Life of plant	Coal
Mid American Energy Company	Council Bluffs 4	52.7	Life of plant	Coal
MEC Participation Waverly, IA	Council Bluffs 4 Participation	3.2	February 2010	Coal
Public Power Generation Agency (3)	Whelan Energy Center 2	0.0	Life of plant	Coal
Short Term Purchase	Purchased Capacity	30.0	August 2007	Purchase
Ainsworth Wind Energy Facility	Renewable Intermittent Resource (Wind)	0.0	Life of plant	7.0 MW Nameplate Wind
East Resource Total		**332.3**		
Basin Electric Power Cooperative	Unit Participation Sale	-30.0	April 2014	Capacity and Energy Sale
East Subtotal		**302.3**		
Current MEAN System Net Total		**577.9**		

1. Expires April 30, 2014; total contract delivery may be reduced to 30 MW when Whelan Energy Center 2 is commercially operational
2. Expires April 30, 2014; total contract delivery may be reduced to 20 MW when Whelan Energy Center 2 is commercially operational
3. Projected Online Date 2011, MEAN will participate in 80 MW of 220 MW

Table 11
Groups Used in Development
of MEAN Load Forecast

Groups	MEAN Total Requirements Participants
1 - West	Aspen, CO; Delta,CO; Gunnison,CO; Lyons,CO and Oak Creek,CO
2 - West	Fort Morgan, CO; Kimball, NE and Sidney, NE
3 - West	Fleming, CO; Haxtun, CO; Holyoke, CO; and Yuma, CO + Yuma Ethanol
4 - West	Gering, NE and Mitchell, NE
5 - West	Lyman, NE and Morrill, NE
6 - West	Bayard, NE and Bridgeport, NE
7 - West	Basin, WY and Torrington, WY + Torrington Prison
8 - East	Benkleman,NE; Chappell,NE; Grant,NE; Imperial, NE and Paxton, NE
9 - East	Beaver City, NE; Curtis, NE and Oxford, NE
10 - East	Blue Hill, NE; Red Cloud, NE; Shickley,NE; and Wood River, NE + Wood River Ethanol
11 - East	Ansley, NE; Arnold, NE; Broken Bow, NE; Burwell, NE; Callaway, NE; Pender, NE; Pierce, NE; Sargent, NE; Spencer, NE and Stuart, NE
12 - East	Plainview, NE and Wisner, NE
13 - East	Crete, NE; Fairbury, NE and West Point, NE
14 - East	Alliance, NE and Julesburg, CO
15 - East	Breda, IA; Buffalo, IA; Carlisle, IA; Denver,IA; Indianola, IA; and Sergeant Bluff, IA; Wall Lake, IA
West	Glenwood Springs, CO
West	Gillette, WY
West	Fountain, CO

Table 12
West Side Participants
Historical and Projected
Peak Demand and Energy Requirements

Year	Total Peak Demand Summer MW	Winter MW	Percent Change	Total Energy Requirements Summer MWh	Winter MWh	Total MWh	Percent Change	Load Factor DLC %
1990-1991	45.8	52.2		78,021	176,784	254,805		55.76%
1991-1992	46.0	48.4	0.31%	77,966	175,114	253,080	-0.07%	59.65%
1992-1993	43.1	86.2	-6.23%	75,128	288,742	363,870	-3.64%	48.03%
1993-1994	75.6	86.1	75.47%	140,204	321,413	461,617	86.62%	61.24%
1994-1995	78.1	93.7	3.29%	155,506	342,337	497,843	10.91%	60.67%
1995-1996	90.6	98.0	15.95%	162,221	362,951	525,172	4.32%	61.15%
1996-1997	100.8	126.4	11.28%	166,804	404,086	570,890	2.83%	51.41%
1997-1998	114.3	122.4	13.40%	167,931	457,694	625,625	0.68%	58.35%
1998-1999	131.7	136.6	15.24%	164,791	496,157	660,948	-1.87%	55.23%
1999-2000	134.6	124.4	2.18%	168,901	500,571	669,472	2.49%	61.45%
2000-2001	140.0	136.7	3.99%	168,791	545,667	714,459	-0.06%	59.50%
2001-2002	143.2	132.0	2.31%	167,341	559,596	726,936	-0.86%	62.86%
2002-2003	153.8	156.2	7.41%	251,968	514,698	766,666	-8.02%	56.90%
2003-2004	181.8	170.0	18.20%	291,859	578,915	870,774	12.48%	54.68%
2004-2005	179.9	224.8	-1.06%	283,683	734,348	1,018,031	26.85%	64.61%
2005-2006	306.7	282.9	70.54%	480,151	927,636	1,407,787	26.32%	52.39%
2006-2007	323.2	285.1	5.36%	533,576	1,017,571	1,551,147	9.70%	54.79%
2007-2008	323.8	291.4	0.19%	490,537	1,029,600	1,520,137	1.18%	53.59%
2008-2009	258.5	232.6	-20.17%	463,249	993,095	1,456,344	-5.56%	59.71%
2009-2010	266.1	239.4	2.93%	479,771	985,110	1,464,881	3.57%	59.71%
2010-2011	275.2	247.7	3.43%	496,134	1,019,015	1,515,149	3.41%	59.71%
2011-2012	283.9	255.5	3.18%	511,812	1,051,501	1,563,313	3.16%	59.71%
2012-2013	292.7	263.4	3.09%	527,531	1,084,074	1,611,605	3.07%	59.71%
2013-2014	301.5	271.4	3.01%	543,326	1,116,803	1,660,128	2.99%	59.71%
2014-2015	310.4	279.4	2.95%	559,294	1,149,890	1,709,184	2.94%	59.71%
2015-2016	319.3	287.4	2.86%	575,195	1,182,838	1,758,033	2.84%	59.71%
2016-2017	328.1	295.3	2.75%	590,935	1,215,454	1,806,390	2.74%	59.71%

Table 13
East Side Participants
Historical and Projected
Peak Demand and Energy Requirements

Year	Total Peak Demand Summer MW	Winter MW	Percent Change	Total Energy Requirements Summer MWh	Winter MWh	Total MWh	Percent Change	Load Factor %
1990-1991	111.4	91.9		181,932	316,775	498,707		51.09%
1991-1992	111.4	85.7	0.01%	187,312	317,981	505,293	2.96%	51.76%
1992-1993	100.6	91.1	-9.70%	167,243	341,949	509,192	-10.71%	57.61%
1993-1994	110.3	92.1	9.59%	176,696	341,015	517,711	5.65%	53.59%
1994-1995	109.9	89.5	-0.35%	190,021	338,292	528,313	7.54%	54.88%
1995-1996	119.3	102.5	8.56%	199,886	355,910	555,797	5.19%	53.18%
1996-1997	120.9	105.2	1.34%	197,374	374,586	571,960	-1.26%	53.86%
1997-1998	125.0	94.3	3.42%	209,421	368,612	578,033	6.10%	52.77%
1998-1999	123.4	100.0	-1.30%	207,379	352,967	560,347	-0.98%	51.83%
1999-2000	128.4	93.9	4.04%	205,770	351,424	557,193	-0.78%	49.54%
2000-2001	131.9	108.6	2.69%	223,303	387,790	611,093	8.52%	52.76%
2001-2002	133.8	100.3	1.50%	219,660	380,838	600,498	-1.63%	51.22%
2002-2003	140.9	117.2	5.32%	238,786	394,895	633,681	8.71%	51.33%
2003-2004	139.9	116.5	-0.73%	230,552	402,520	633,072	-3.45%	51.66%
2004-2005	145.7	131.3	4.15%	223,314	433,781	657,095	-3.14%	51.49%
2005-2006	160.7	144.3	10.29%	265,913	479,584	745,496	19.08%	52.96%
2006-2007	168.6	146.3	4.94%	277,583	503,914	781,496	4.39%	52.91%
2007-2008	197.2	177.5	16.96%	299,029	600,584	899,612	7.73%	52.07%
2008-2009	203.2	182.9	3.05%	365,961	652,897	1,018,859	22.38%	52.07%
2009-2010	207.1	186.4	1.89%	372,047	665,261	1,037,308	1.66%	52.07%
2010-2011	210.6	189.5	1.68%	378,047	675,995	1,054,042	1.61%	52.07%
2011-2012	213.8	192.4	1.53%	383,599	685,928	1,069,528	1.47%	52.07%
2012-2013	217.0	195.3	1.51%	389,174	695,901	1,085,075	1.45%	52.07%
2013-2014	220.3	198.2	1.49%	394,740	705,859	1,100,600	1.43%	52.07%
2014-2015	223.5	201.1	1.46%	400,282	715,775	1,116,057	1.40%	52.07%
2015-2016	226.7	204.1	1.45%	405,870	725,771	1,131,640	1.40%	52.07%
2016-2017	230.0	207.0	1.44%	411,508	735,857	1,147,365	1.39%	52.07%

Table 14
Comparison of Peak Demand and Enegy Requirements to Resources
West Side

	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017
Demand, MW										
Projected Demand	323.8	258.5	266.1	275.2	283.9	292.7	301.5	310.4	319.3	328.1
Required Reserves (1)	26.0	20.2	21.3	22.8	24.1	25.5	26.8	28.1	29.4	30.8
Peak Demand Obligation	349.8	278.7	287.4	298.0	308.1	318.2	328.3	338.5	348.7	358.8
Capacity Resources	309.6	206.9	206.9	206.1	206.1	206.1	166.1	166.1	166.1	166.1
Surplus/(Deficit)	**(40.2)**	**(71.7)**	**(80.4)**	**(91.9)**	**(101.9)**	**(112.0)**	**(162.2)**	**(172.4)**	**(182.6)**	**(192.7)**
Energy, MWh										
Energy Obligation	1,520,137	1,456,344	1,464,881	1,515,149	1,563,313	1,611,605	1,660,128	1,709,184	1,758,033	1,806,390
Energy Resources	1,157,089	861,431	861,431	858,960	858,960	858,960	561,120	561,120	561,120	561,120
Surplus/(Deficit)	**(363,048)**	**(594,913)**	**(603,450)**	**(656,188)**	**(704,352)**	**(752,644)**	**(1,099,008)**	**(1,148,064)**	**(1,196,913)**	**(1,245,269)**
Deficit Capacity Factor	103%	95%	86%	82%	79%	77%	77%	76%	75%	74%

Notes:
(1) 15% required reserves for load not supplied by firm resources

Table 15
Comparison of Peak Demand and Enegy Requirements to Resources
East Side

	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017
Demand, MW										
Projected Demand	197.2	203.2	207.1	210.6	213.8	217.0	220.3	223.5	226.7	230.0
Firm Sales	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Required Reserves (1)	30.0	30.6	31.1	31.7	32.2	32.7	33.2	33.6	34.1	34.6
Peak Demand Obligation	261.2	267.8	272.2	276.2	280.0	283.7	287.4	291.1	294.9	298.6
Capacity Resources	302.3	274.4	264.4	261.3	291.0	291.0	291.0	271.0	271.0	271.0
Surplus/(Deficit)	**41.1**	**6.6**	**(7.8)**	**(15.0)**	**11.1**	**7.3**	**3.6**	**(20.1)**	**(23.8)**	**(27.6)**
Energy, MWh										
Energy Obligation	899,612	1,018,859	1,037,308	1,054,042	1,069,528	1,085,075	1,100,600	1,116,057	1,131,640	1,147,365
Energy Resources	1,322,555	1,322,555	1,248,095	1,224,291	1,446,598	1,446,598	1,446,598	1,297,678	1,297,678	1,297,678
Surplus/(Deficit)	**422,943**	**303,697**	**210,788**	**170,249**	**377,070**	**361,523**	**345,998**	**181,621**	**166,038**	**150,313**

Notes:
(1) 15% required reserves for load not supplied by firm resources

Table 16
Qualitative Screening
Residential Demand Side Options

Technology Alternative	Cost	Customer Preference	Environmental Impact	Market Potential	Ease of Implementation	Commercial Availability/ Reliability	Total
Residential Central Air Conditioning Load Cycling	2	2	2	3	2	3	14
Residential Electric Water Heater Load Shedding	1	3	3	1	3	3	14
Residential High Efficiency Central Air Conditioners	2	3	3	3	2	3	16
Residential Room and Window Air Conditioner Rebates	2	3	3	3	3	3	17
High Efficiency Refrigerator Rebate Program	2	3	3	3	3	3	17
Old Refrigerator Pick-up Program	2	2	3	3	3	3	16
Improved Home Loan Program for Furnace & AC Replacement	1	3	3	3	3	3	16
Energy-Efficient New Home	1	2	3	2	2	2	12
Energy-Efficient Existing Home	1	2	3	2	2	2	12
Compact Fluorescent Lighting	3	3	3	3	3	3	18
Residential Tree Planting Program	3	3	3	3	2	2	16

Table 17
Qualitative Screening
Commercial/Industrial Demand Side Options

Technology Alternative	Cost	Customer Preference	Environmental Impact	Market Potential	Ease of Implementation	Commercial Availability/ Reliability	Total
Commercial High-Efficiency Lighting	3	3	3	1	2	3	15
Commercial High-Efficiency Air Conditioners	1	3	2	2	3	3	14
Commercial HVAC Efficiency Improvement Program	2	2	3	2	2	3	14
Large Customer Customized Rebate Program	1	3	3	2	2	3	14
Interruptible Rates	3	3	3	1	2	3	15

Table 18
Summary of DSM Options
Project Costs and Savings
(2007$)

Demand Side Management Alternatives	Present Value ($/per Unit)
Residential Central Air Conditioning Load Cycling	($54.87)
Residential Electric Water Heater Load Shedding	($124.92)
Residential High Efficiency Central Air Conditioners	($13.02)
Residential Room and Window Air Conditioner Rebates	($36.40)
High Efficiency Refrigerator Rebate Program	($19.29)
Old Refrigerator Pick-up Program	($16.06)
Improved Home Loan Program for Furnace & AC Replacement	($620.22)
Energy-Efficient New Home	($437.66)
Energy-Efficient Existing Home	($1,116.18)
Compact Fluorescent Lighting	$56.20
Commercial High-Efficiency Lighting	$1,029.33
Commercial High-Efficiency Air Conditioners	($111.77)
Commercial HVAC Efficiency Improvement Program	($10.21)
Large Customer Customized Rebate Program	($490.66)
Interruptible Rates	$10,723.32
Residential Tree Planting Program	($89.58)

Table 19
Resource Additions
Recommended Integrated Resource Plan
West Side

	Fiscal Year									
	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017
Peak Demand Obligation (1)	349.8	278.7	287.4	298.0	308.1	318.2	328.3	338.5	348.7	358.8
West Member Gen	45.1	25.1	25.1	25.1	25.1	25.1	25.1	25.1	25.1	25.1
WAPA	116.5	89.8	89.8	89.0	89.0	89.0	89.0	89.0	89.0	89.0
Black Hills Power and Light	40.0	40.0	40.0	40.0	40.0	0.0	0.0	0.0	0.0	0.0
Laramie River Station	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
Platte River Power Authority	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Public Service Company of Colorado	26.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WAPA Displacement	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0
Sidney DC Tie	41.0	37.0	36.0	24.0	35.0	40.0	38.0	39.0	40.0	40.0
Baseload Addition 1						**40.0**	**40.0**	**40.0**	**40.0**	**40.0**
Combined Cycle				**68.0**	**68.0**	**68.0**	**0.0**	**0.0**	**0.0**	**0.0**
Baseload Addition 2							**80.0**	**80.0**	**80.0**	**80.0**
On-Peak Capacity/Energy	**20.0**	**35.0**	**45.0**	**0.0**	**0.0**	**5.0**	**5.0**	**15.0**	**25.0**	**35.0**
Capacity/Reserve	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Surplus/(Deficit)	0.8	0.2	0.5	0.1	1.0	1.0	0.8	1.6	2.4	2.3

Notes:
(1) Included forecast demand and 15% required reserves for load not supplied by firm resources.

Table 20
Resource Additions
Recommended Integrated Resource Plan
East Side

	Fiscal Year									
	2007-2008	2008-2009	2009-2010	2010-2011	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017
Peak Demand Obligation (1)	261.2	267.8	272.2	276.2	280.0	283.7	287.4	291.1	294.9	298.6
East Member Gen	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
WAPA	31.4	33.5	33.5	33.4	33.2	33.2	33.2	33.2	33.2	33.2
NPPD Cooper	60.0	60.0	60.0	60.0	30.0	30.0	30.0	0.0	0.0	0.0
NPPD GGS	40.0	40.0	40.0	40.0	20.0	20.0	20.0	0.0	0.0	0.0
Laramie River Station	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Hastings Purchase	10.0	10.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
MEC Council Bluffs 4	52.7	52.7	52.7	52.7	52.7	52.7	52.7	52.7	52.7	52.7
CB 4 Waverly Purchase	3.2	3.2	3.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WEC 2	0.0	0.0	0.0	0.0	80.0	80.0	80.0	80.0	80.0	80.0
Sale to BEPC	-30.0	-30.0	-30.0	-30.0	-30.0	-30.0	-30.0	0.0	0.0	0.0
Sidney DC Tie	-41.0	-37.0	-36.0	-24.0	-35.0	-40.0	-38.0	-39.0	-40.0	-40.0
Baseload Addition	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
On Peak Capacity/Energy	**30.0**	**35.0**	**45.0**	**40.0**	**35.0**	**35.0**	**35.0**	**60.0**	**65.0**	**70.0**
Surplus/(Deficit)	0.0	4.5	1.1	0.8	10.9	2.1	0.4	0.7	1.0	2.2

Notes:
(1) Included forecast demand and 15% required reserves for load not supplied by firm resources.

Figure 6 MEAN Load Duration Curve - 2012 West Side

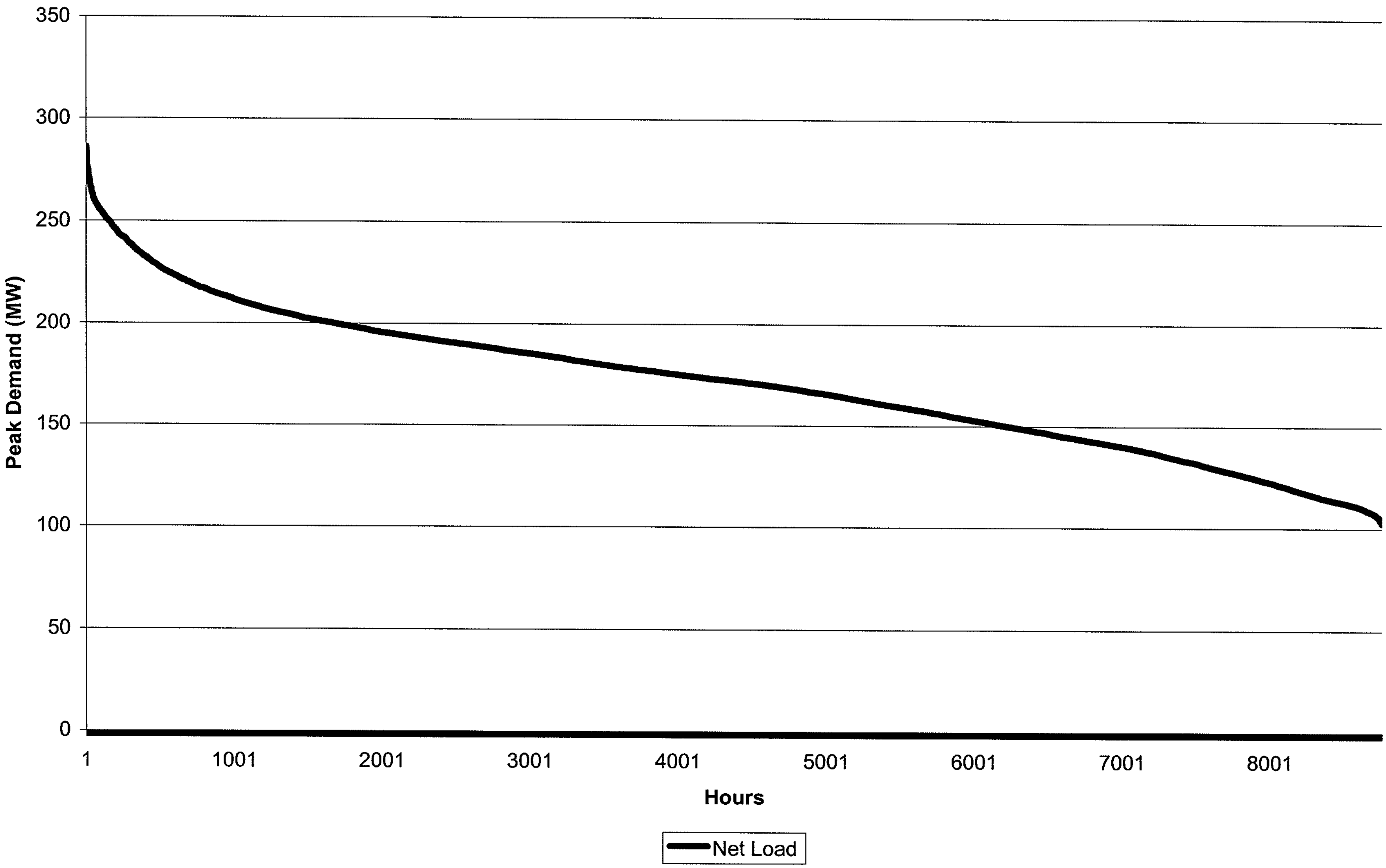


Figure 7 MEAN Load Duration Curve - 2012 East Side

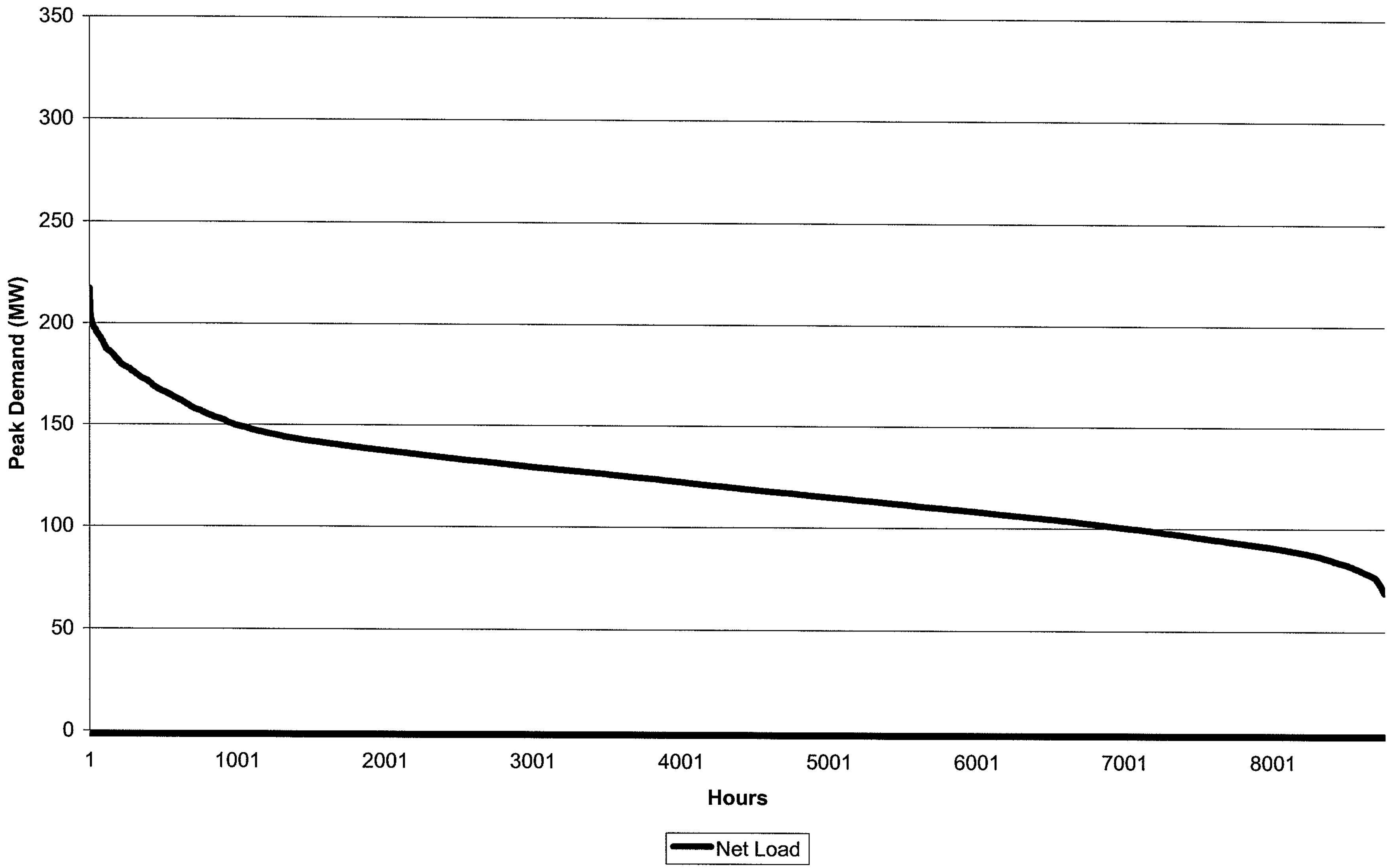


Figure 8 Forecast Peak Demand West Side

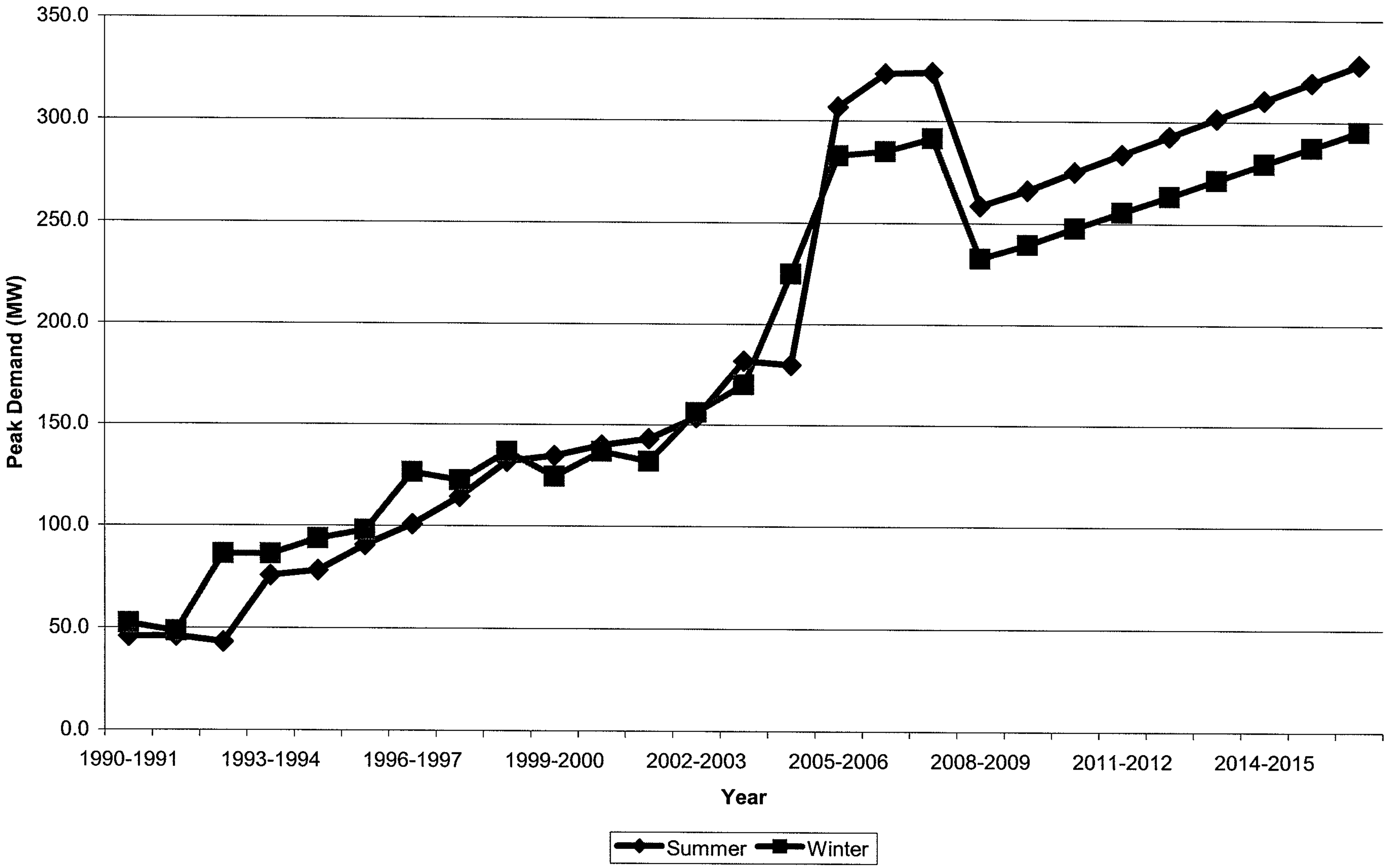
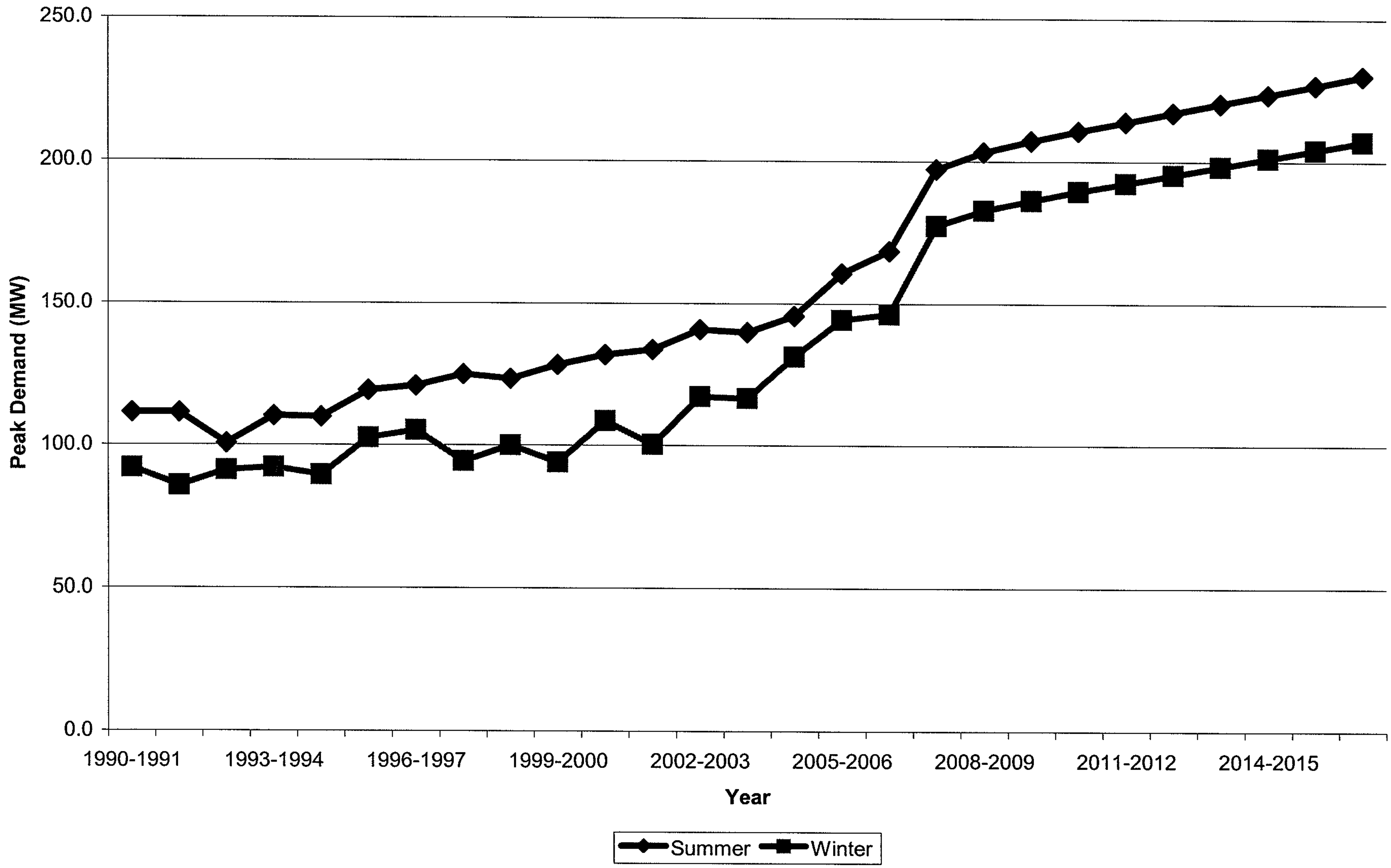


Figure 9 Forecast Peak Demand East Side



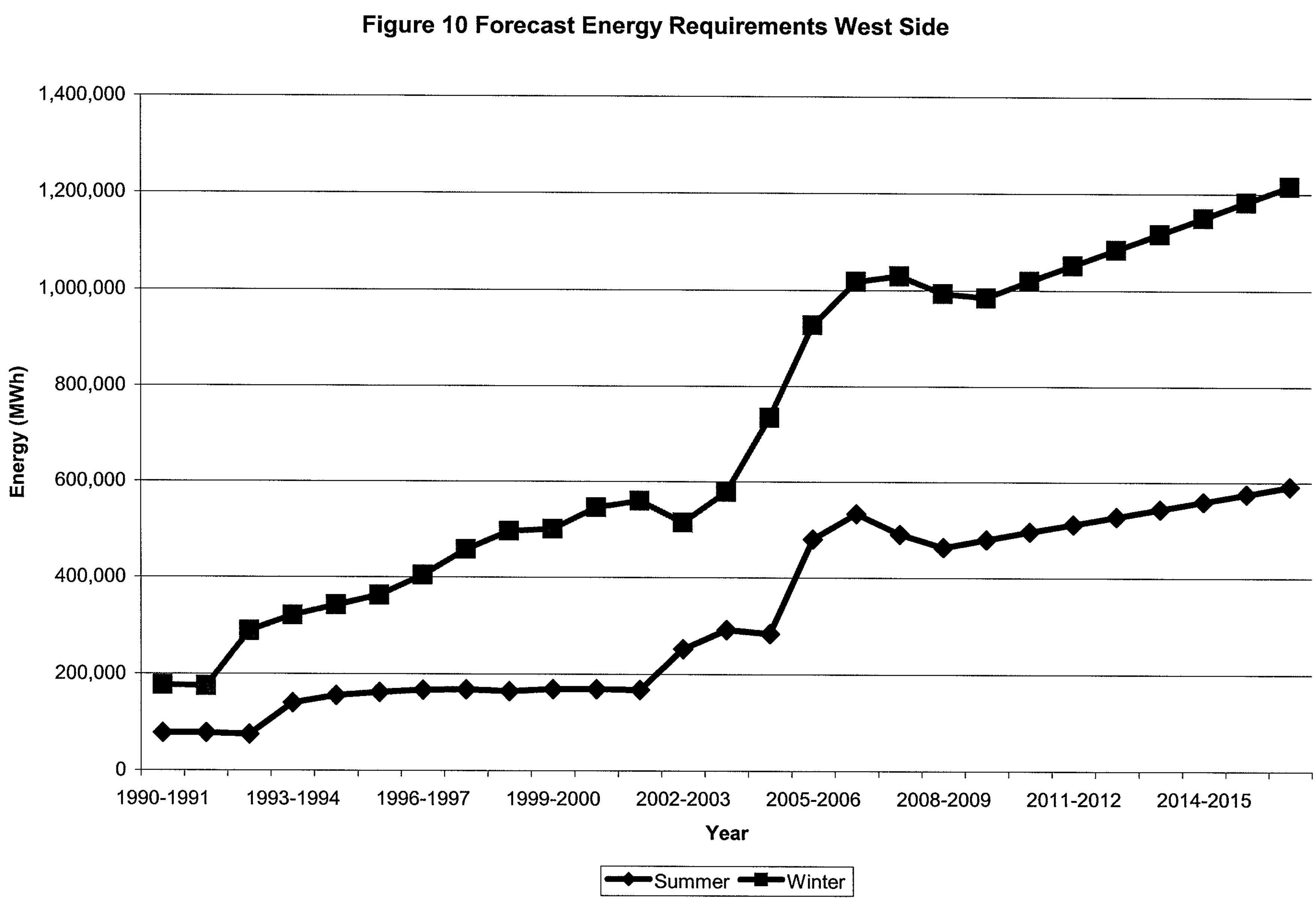


Figure 10 Forecast Energy Requirements West Side
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
Energy (MWh)
1990-1991
1993-1994
1996-1997
1999-2000
2002-2003
2005-2006
2008-2009
2011-2012
2014-2015
Year
Summer
Winter

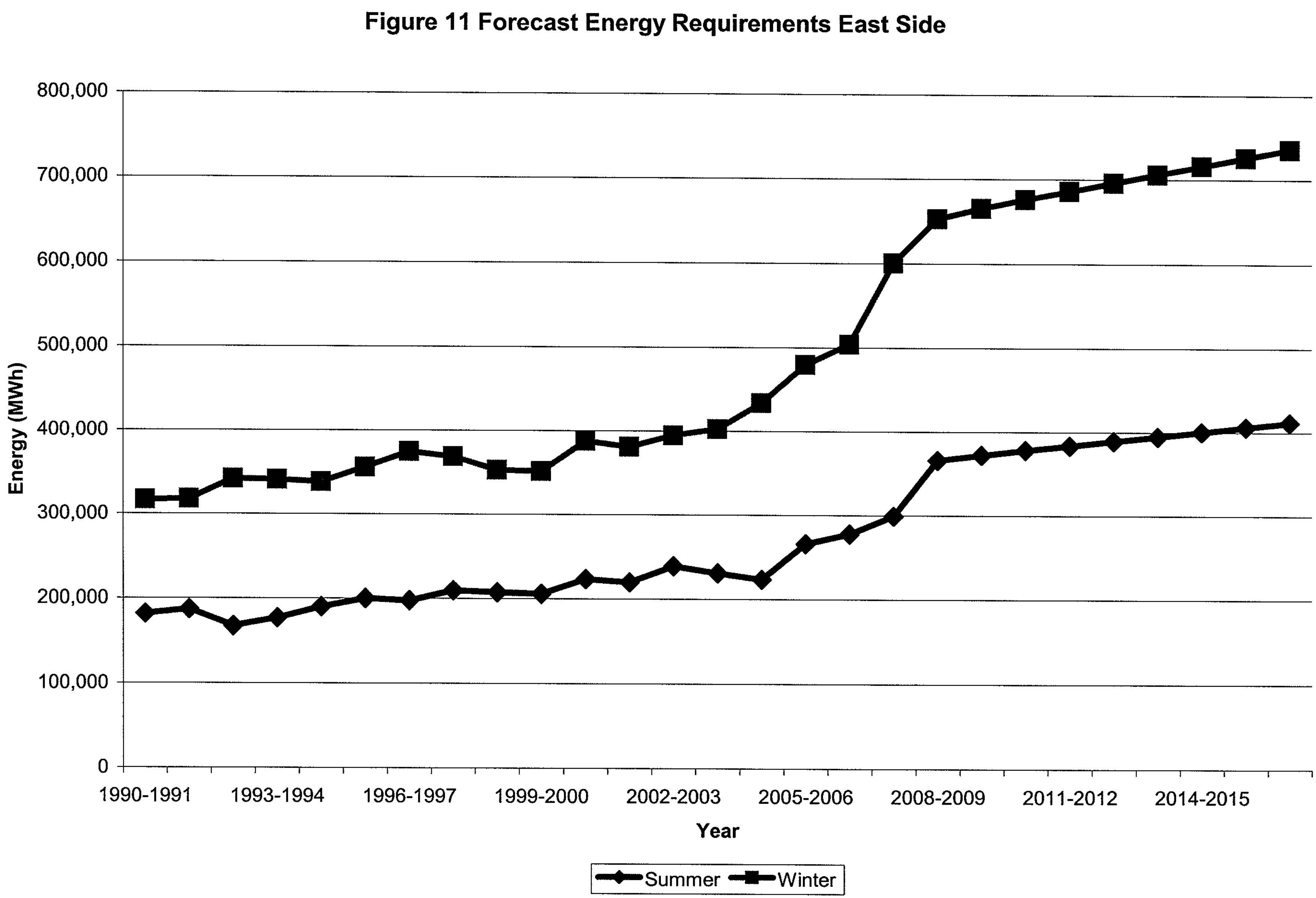


Figure 11 Forecast Energy Requirements East Side
800,000
700,000
600,000
500,000
400,000
300,000
200,000
100,000
0
Energy (MWh)
1990-1991
1993-1994
1996-1997
1999-2000
2002-2003
2005-2006
2008-2009
2011-2012
2014-2015
Year
Summer
Winter

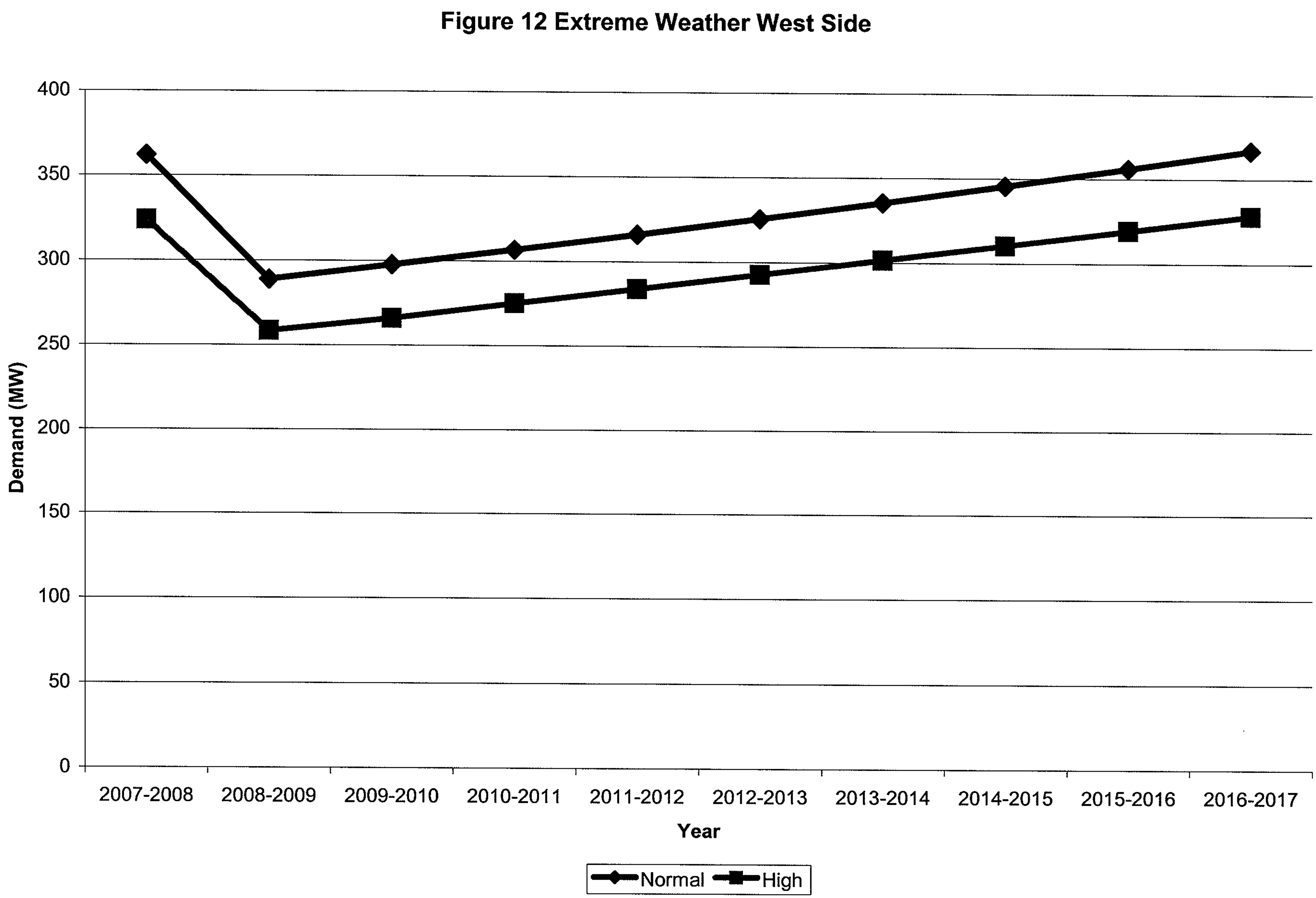


Figure 12 Extreme Weather West Side
Demand (MW)
400
350
300
250
200
150
100
50
0
2007-2008
2008-2009
2009-2010
2010-2011
2011-2012
2012-2013
2013-2014
2014-2015
2015-2016
2016-2017
Year
Normal
High

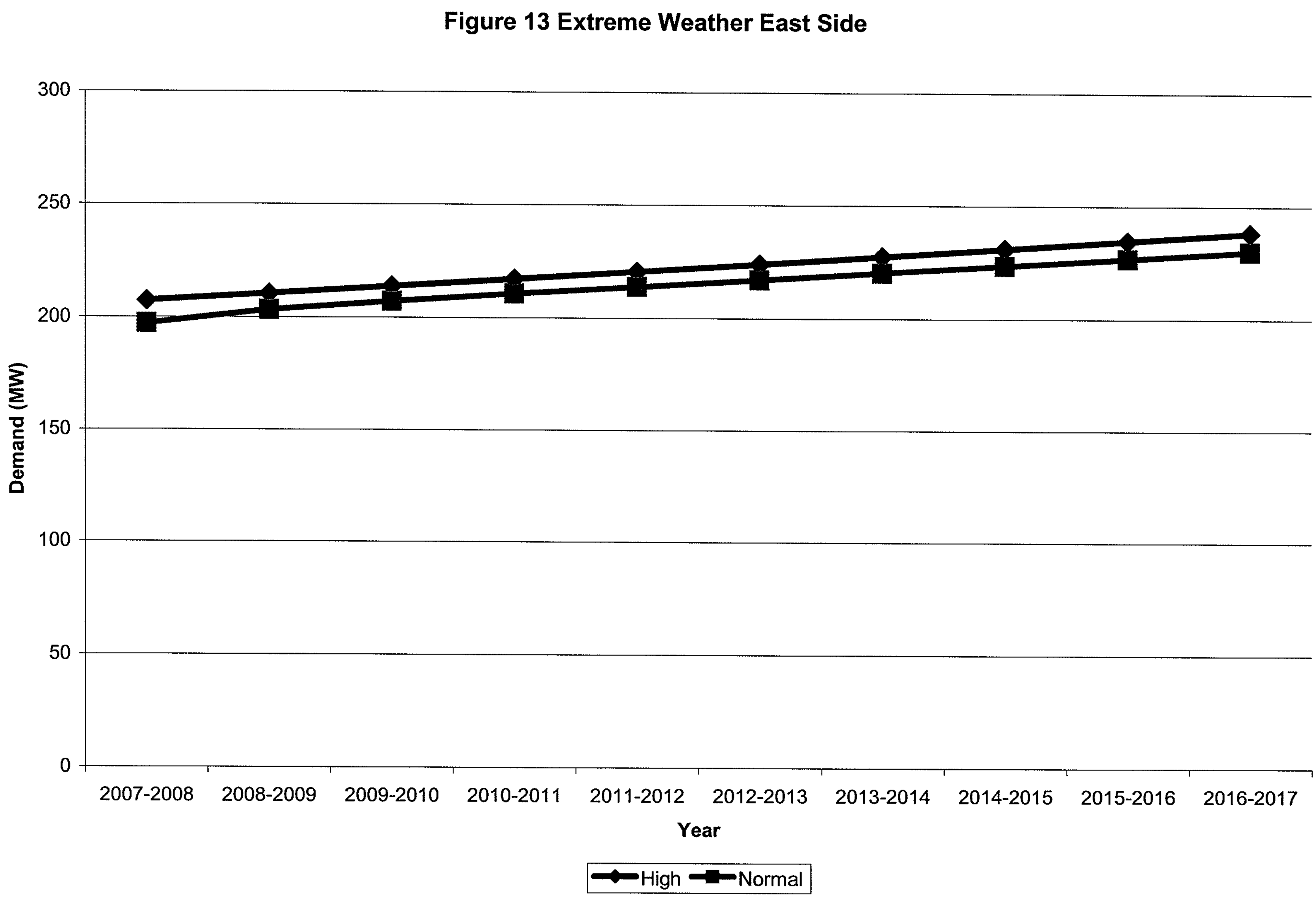


Figure 13 Extreme Weather East Side
300
250
200
150
100
50
0
Demand (MW)
2007-2008
2008-2009
2009-2010
2010-2011
2011-2012
2012-2013
2013-2014
2014-2015
2015-2016
2016-2017
Year
High
Normal

Figure 14
Resource Screening Curve 2012 $

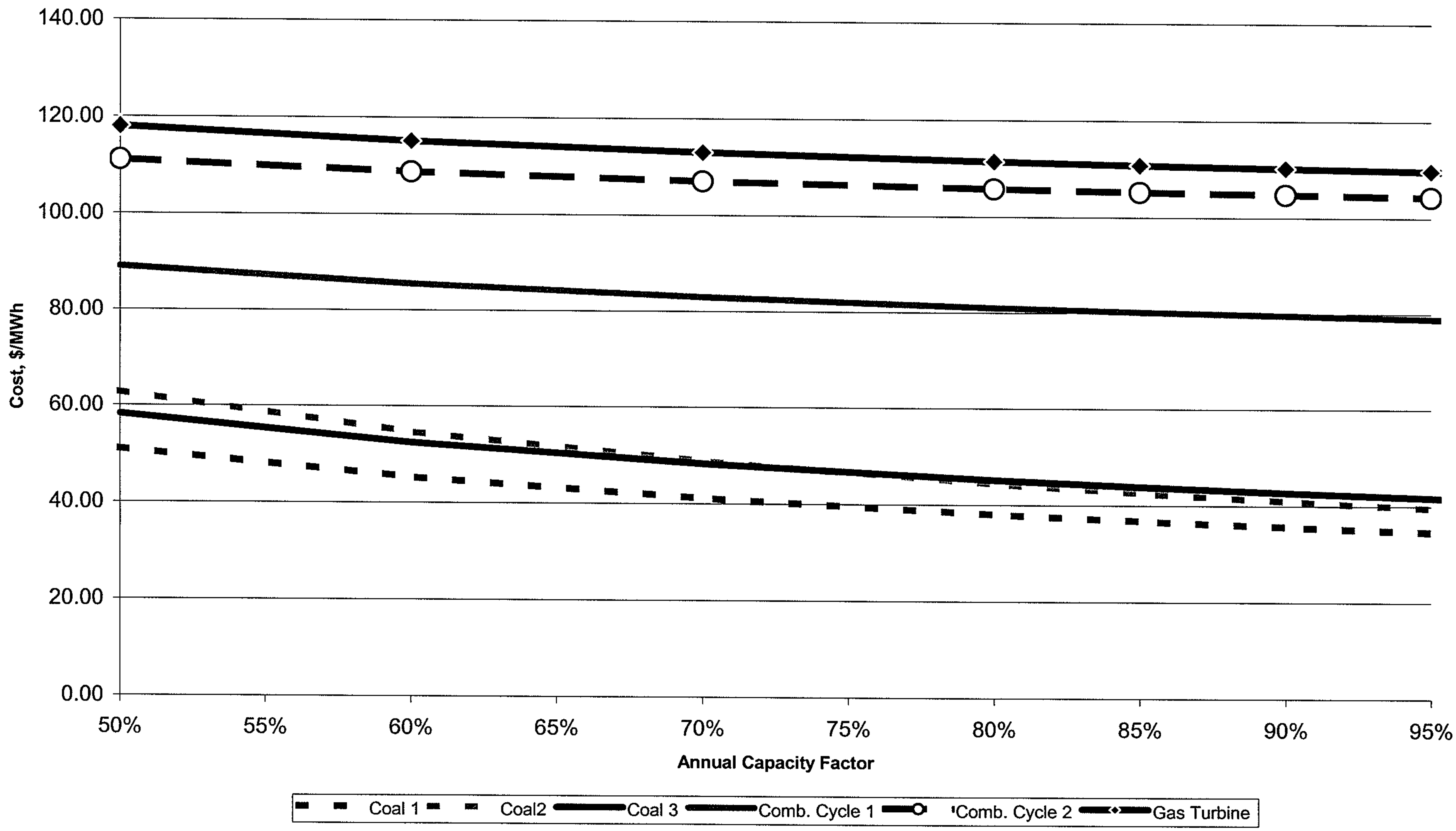


Figure 15
Resource Screening Curve 2012 $

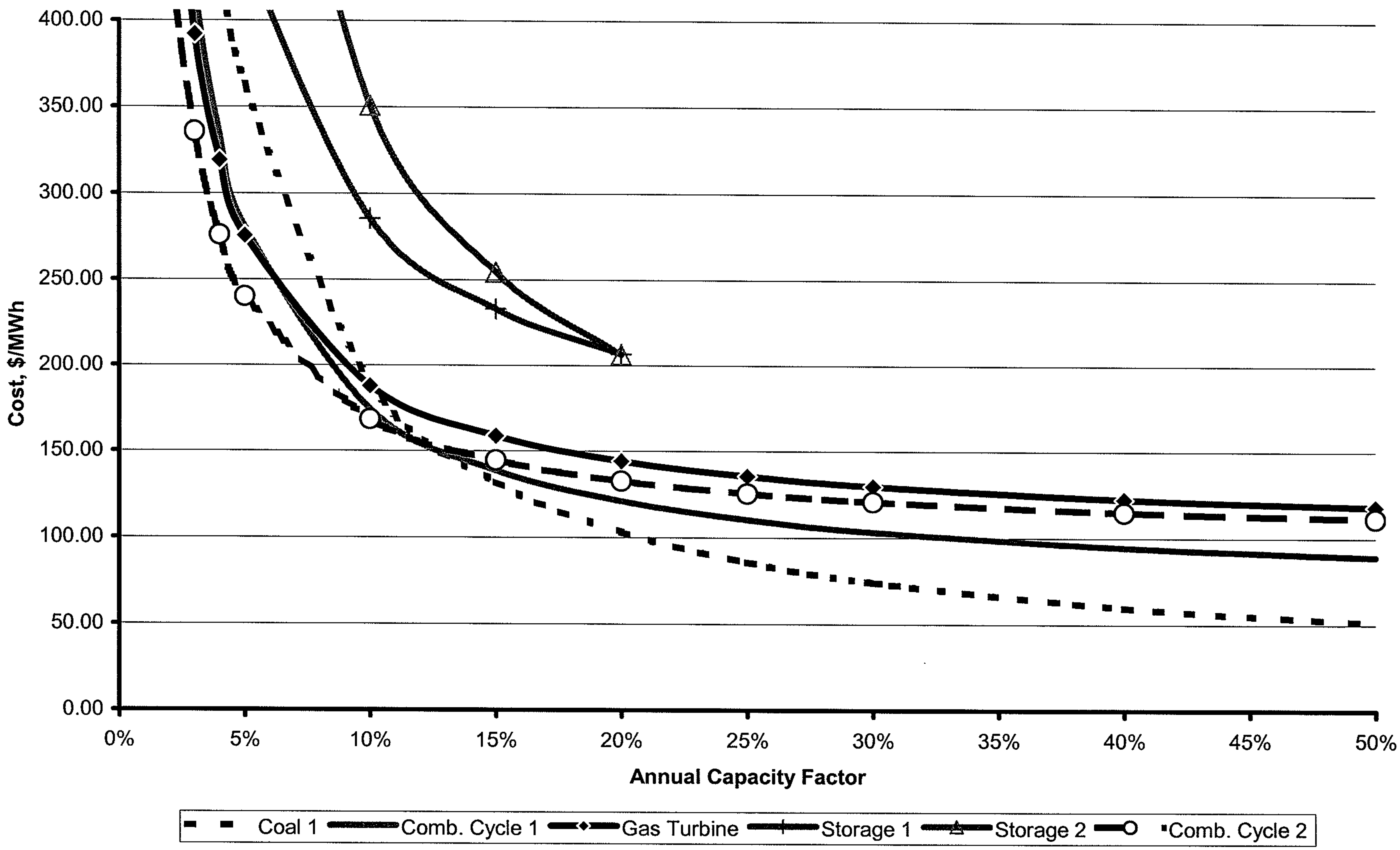


Figure 16 Resource Additions Recommended Integrated Resource Plan West Side

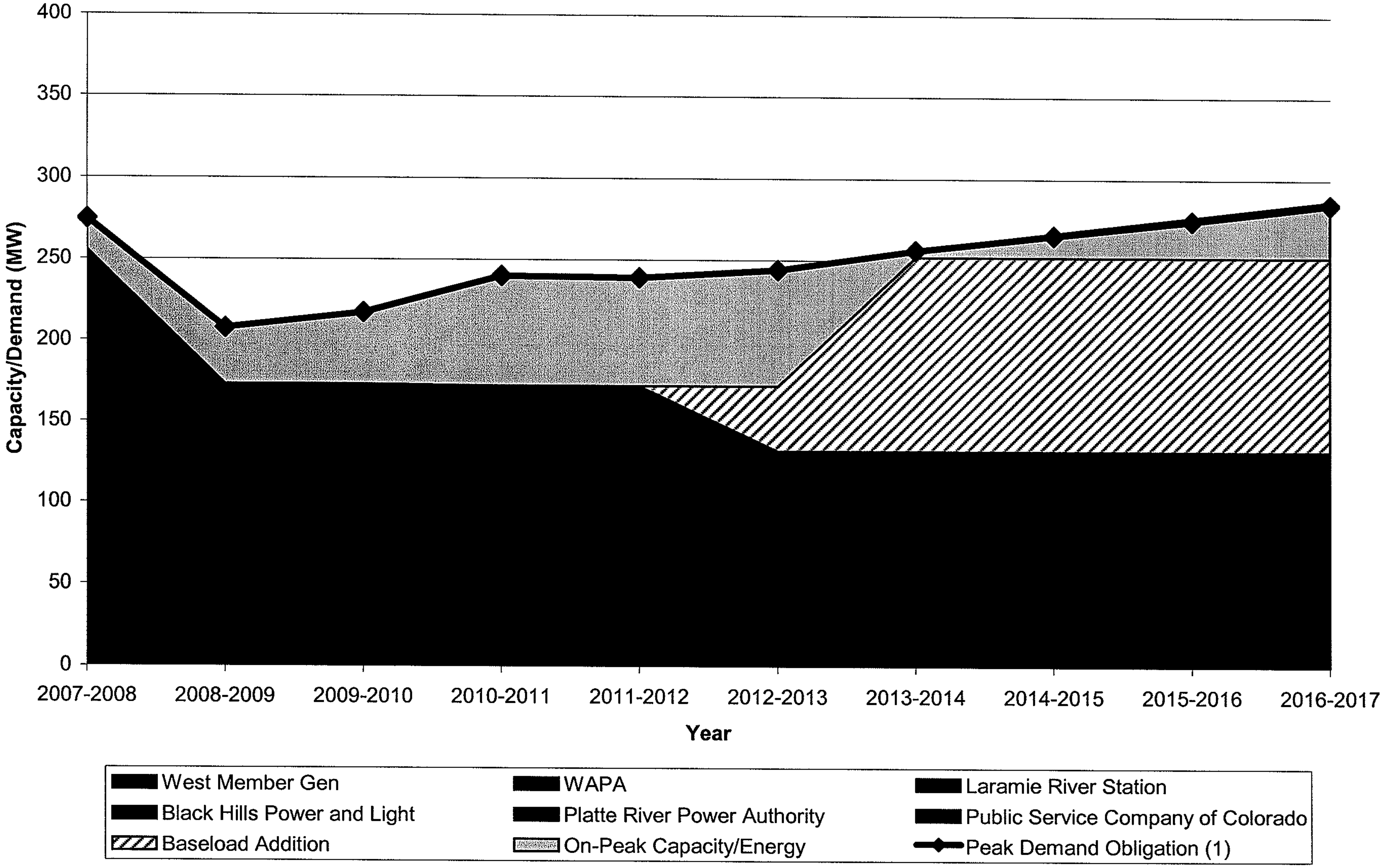
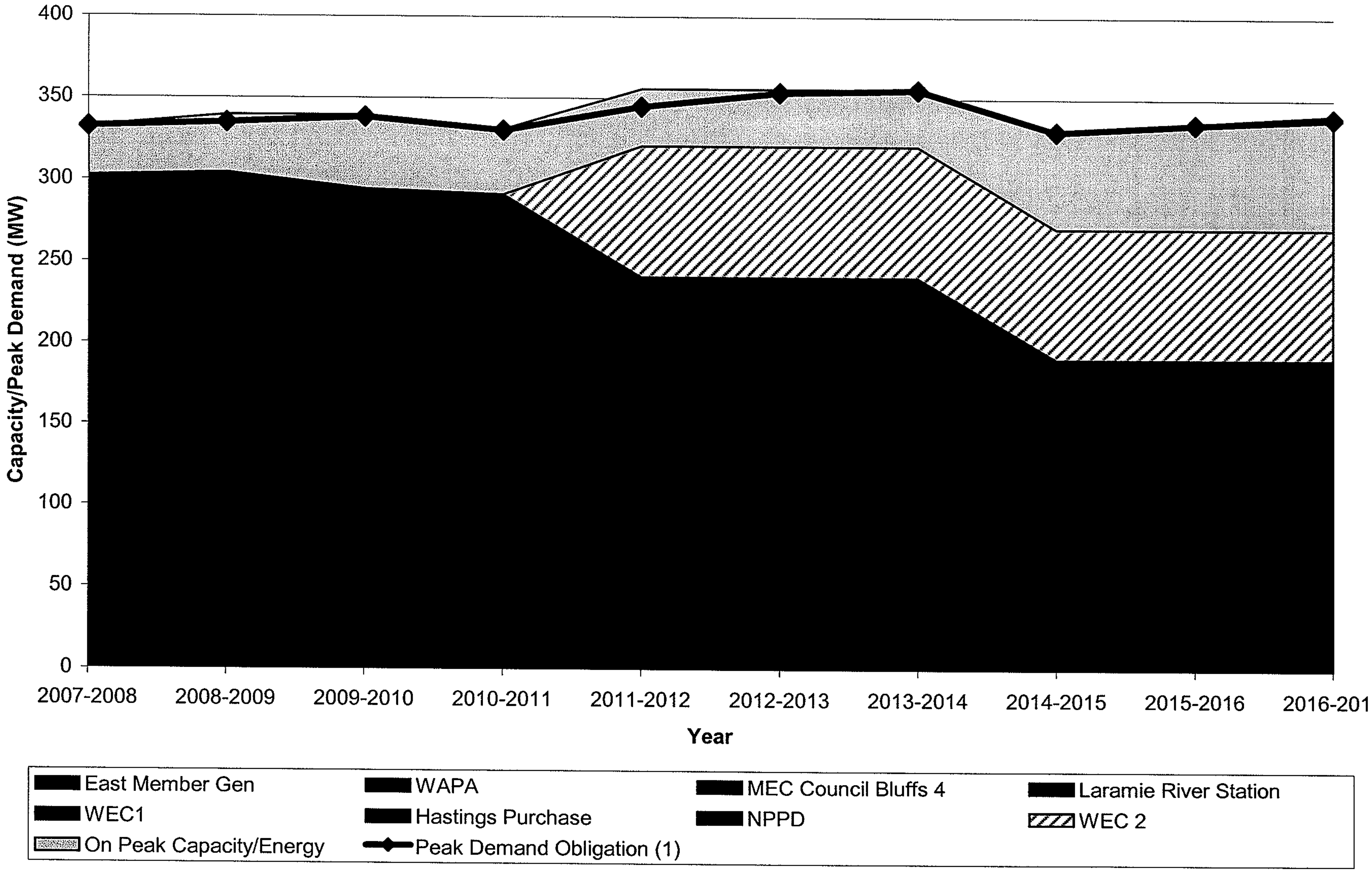


Figure 17 Resource Additions Recommended Integrated Resource Plan East Side



Appendix C
Impact of DSM Options
Residential Central Air Conditioning Load Cycling

DSM Technology Residential	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**0.85**	**0.00**	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**10**
Estimated Residential Customers	107,000	107,000	107,000
Estimated Appliance Saturation	59.00%	59.00%	59.00%
Market Eligibility	40.00%	40.00%	40.00%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	25,252	25,252	25,252
Total Demand or Energy Savings (kW or kWh)	**21,464**	**0**	**252,520**

Estimated Installation Cost per Unit	$175.30
Estimated Annual Maintenance Cost per Unit	$6.86
Measure Life	25 Years
Discount Rate	5.00%

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)	Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	0.85	0.00	10	$5.75	$0.00	$31.83	$19.87
2008	0.85	0.00	10	$5.87	$0.00	$32.46	$20.27
2009	0.85	0.00	10	$5.98	$0.00	$33.11	$20.67
2010	0.85	0.00	10	$6.10	$0.00	$33.77	$21.08
2011	0.85	0.00	10	$6.22	$0.00	$34.45	$21.51
2012	0.85	0.00	10	$6.35	$0.00	$35.14	$21.94
2013	0.85	0.00	10	$6.48	$0.00	$35.84	$22.37
2014	0.85	0.00	10	$6.60	$0.00	$36.56	$22.82
2015	0.85	0.00	10	$6.74	$0.00	$37.29	$23.28
2016	0.85	0.00	10	$6.87	$0.00	$38.03	$23.74

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$175.30	$19.87	($155.43)	($155.43)
2008	$6.86	$20.27	$13.41	$12.77
2009	$7.07	$20.67	$13.60	$12.34
2010	$7.28	$21.08	$13.80	$11.92
2011	$7.50	$21.51	$14.01	$11.53
2012	$7.73	$21.94	$14.21	$11.13
2013	$7.96	$22.37	$14.41	$10.75
2014	$8.20	$22.82	$14.62	$10.39
2015	$8.45	$23.28	$14.83	$10.04
2016	$8.70	$23.74	$15.04	$9.69
Total	$245.05	$217.55	($27.50)	($54.87)

Footnote #1
Footnote #2
Footnote #3
Footnote #4

Appendix C
Impact of DSM Options
Residential Electric Water Heater Load Shedding

DSM Technology Residential	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**0.45**	**0.00**	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**5**
Estimated Residential Customers	107,000	107,000	107,000
Estimated Appliance Saturation	15.00%	15.00%	15.00%
Market Eligibility	50.00%	50.00%	50.00%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	8,025	8,025	8,025
Total Demand or Energy Savings (kW or kWh)	**3611**	**0**	**40,125**

Estimated Installation Cost per Unit	$194.65
Estimated Annual Maintenance Cost per Unit	$2.87
Measure Life	25 Years
Discount Rate	5.00%

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)	Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	0.45	0.00	5	$5.75	$0.00	$31.83	$10.51
2008	0.45	0.00	5	$5.87	$0.00	$32.46	$10.72
2009	0.45	0.00	5	$5.98	$0.00	$33.11	$10.93
2010	0.45	0.00	5	$6.10	$0.00	$33.77	$11.15
2011	0.45	0.00	5	$6.22	$0.00	$34.45	$11.38
2012	0.45	0.00	5	$6.35	$0.00	$35.14	$11.60
2013	0.45	0.00	5	$6.48	$0.00	$35.84	$11.83
2014	0.45	0.00	5	$6.60	$0.00	$36.56	$12.07
2015	0.45	0.00	5	$6.74	$0.00	$37.29	$12.31
2016	0.45	0.00	5	$6.87	$0.00	$38.03	$12.56

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$194.65	$10.51	($184.14)	($184.14)
2008	$2.87	$10.72	$7.85	$7.48
2009	$2.96	$10.93	$7.97	$7.23
2010	$3.05	$11.15	$8.10	$7.00
2011	$3.14	$11.38	$8.24	$6.78
2012	$3.23	$11.60	$8.37	$6.56
2013	$3.33	$11.83	$8.50	$6.34
2014	$3.43	$12.07	$8.64	$6.14
2015	$3.53	$12.31	$8.78	$5.94
2016	$3.64	$12.56	$8.92	$5.75
Total	$223.83	$115.06	($108.77)	($124.92)

Footnote #1
Footnote #2
Footnote #3
Footnote #4

Appendix C
Impact of DSM Options
Residential High Efficiency Central Air Conditioners

DSM Technology Residential	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**0.90**	**0.00**	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**500**
Estimated Residential Customers	107,000	107,000	107,000
Estimated Appliance Saturation	59.00%	59.00%	59.00%
Market Eligibility	50.00%	50.00%	50.00%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	31,565	31,565	31,565
Total Demand or Energy Savings (kW or kWh)	**28,409**	**0**	**15,782,500**

Estimated Installation Cost per Unit	$325.28	
Estimated Annual Maintenance Cost per Unit	$0.07	
Measure Life	20	Years
Discount Rate	5.00%	

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)	Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	0.9	0.00	500	$5.75	$0.00	$31.83	$36.93
2008	0.9	0.00	500	$5.87	$0.00	$32.46	$37.67
2009	0.9	0.00	500	$5.98	$0.00	$33.11	$38.42
2010	0.9	0.00	500	$6.10	$0.00	$33.77	$39.19
2011	0.9	0.00	500	$6.22	$0.00	$34.45	$39.98
2012	0.9	0.00	500	$6.35	$0.00	$35.14	$40.77
2013	0.9	0.00	500	$6.48	$0.00	$35.84	$41.59
2014	0.9	0.00	500	$6.60	$0.00	$36.56	$42.42
2015	0.9	0.00	500	$6.74	$0.00	$37.29	$43.27
2016	0.9	0.00	500	$6.87	$0.00	$38.03	$24.74

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$325.28	$36.93	($288.35)	($288.35)
2008	$0.07	$37.67	$37.60	$35.81
2009	$0.07	$38.42	$38.35	$34.78
2010	$0.07	$39.19	$39.12	$33.79
2011	$0.07	$39.98	$39.91	$32.83
2012	$0.07	$40.77	$40.70	$31.89
2013	$0.07	$41.59	$41.52	$30.98
2014	$0.07	$42.42	$42.35	$30.10
2015	$0.07	$43.27	$43.20	$29.24
2016	$0.07	$24.74	$24.67	$15.90
Total	$325.91	$384.98	$59.07	($13.02)

Footnote #1
Footnote #2
Footnote #3
Footnote #4

Appendix C
Impact of DSM Options
Residential Room and Window Air Conditioner Rebates

DSM Technology Residential	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**0.138**	**0.00**	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**103**
Estimated Residential Customers	107,000	107,000	107,000
Estimated Appliance Saturation	33.00%	33.00%	33.00%
Market Eligibility	15.00%	15.00%	15.00%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	5,297	5,297	5,297
Total Demand or Energy Savings (kW or kWh)	**731**	**0**	**545,591**

Estimated Installation Cost per Unit	$92.44	
Estimated Annual Maintenance Cost per Unit	$0.11	
Measure Life	13	Years
Discount Rate	5.00%	

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)	Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	0.138	0.00	103	$5.75	$0.00	$31.83	$6.45
2008	0.138	0.00	103	$5.87	$0.00	$32.46	$6.58
2009	0.138	0.00	103	$5.98	$0.00	$33.11	$6.71
2010	0.138	0.00	103	$6.10	$0.00	$33.77	$6.85
2011	0.138	0.00	103	$6.22	$0.00	$34.45	$6.98
2012	0.138	0.00	103	$6.35	$0.00	$35.14	$7.12
2013	0.138	0.00	103	$6.48	$0.00	$35.84	$7.27
2014	0.138	0.00	103	$6.60	$0.00	$36.56	$7.41
2015	0.138	0.00	103	$6.74	$0.00	$37.29	$7.56
2016	0.138	0.00	103	$6.87	$0.00	$38.03	$7.71

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$92.44	$6.45	($85.99)	($85.99)
2008	$0.11	$6.58	$6.47	$6.16
2009	$0.11	$6.71	$6.60	$5.99
2010	$0.11	$6.85	$6.74	$5.82
2011	$0.11	$6.98	$6.87	$5.65
2012	$0.11	$7.12	$7.01	$5.49
2013	$0.11	$7.27	$7.16	$5.34
2014	$0.11	$7.41	$7.30	$5.19
2015	$0.11	$7.56	$7.45	$5.04
2016	$0.11	$7.71	$7.60	$4.90
Total	$93.43	$70.64	($22.79)	($36.40)

Footnote #1
Footnote #2
Footnote #3
Footnote #4

Appendix C
Impact of DSM Options
High Efficiency Refrigerator Rebate Program

DSM Technology Residential	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**0.082**	**0.082**	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**519**
Estimated Residential Customers	107,000	107,000	107,000
Estimated Appliance Saturation	100.00%	100.00%	100.00%
Market Eligibility	15.00%	15.00%	15.00%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	16,050	16,050	16,050
Total Demand or Energy Savings (kW or kWh)	**1,316**	**1,316**	**8,329,950**

Estimated Installation Cost per Unit	$180.37	
Estimated Annual Maintenance Cost per Unit	$0.14	
Measure Life	10	Years
Discount Rate	5.00%	

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)	Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	0.082	0.08	519	$5.75	$0.00	$31.83	$18.40
2008	0.082	0.08	519	$5.87	$0.00	$32.46	$18.77
2009	0.082	0.08	519	$5.98	$0.00	$33.11	$19.15
2010	0.082	0.08	519	$6.10	$0.00	$33.77	$19.53
2011	0.082	0.08	519	$6.22	$0.00	$34.45	$19.92
2012	0.082	0.08	519	$6.35	$0.00	$35.14	$20.32
2013	0.082	0.08	519	$6.48	$0.00	$35.84	$20.72
2014	0.082	0.08	519	$6.60	$0.00	$36.56	$21.14
2015	0.082	0.08	519	$6.74	$0.00	$37.29	$21.56
2016	0.082	0.08	519	$6.87	$0.00	$38.03	$21.99

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$180.37	$18.40	($161.97)	($161.97)
2008	$0.14	$18.77	$18.63	$17.74
2009	$0.14	$19.15	$19.01	$17.24
2010	$0.14	$19.53	$19.39	$16.75
2011	$0.14	$19.92	$19.78	$16.27
2012	$0.14	$20.32	$20.18	$15.81
2013	$0.14	$20.72	$20.58	$15.36
2014	$0.14	$21.14	$21.00	$14.92
2015	$0.14	$21.56	$21.42	$14.50
2016	$0.14	$21.99	$21.85	$14.08
Total	$181.63	$201.50	$19.87	($19.29)

Footnote #1
Footnote #2
Footnote #3
Footnote #4

Appendix C
Impact of DSM Options
Old Refrigerator Pick-up Program

DSM Technology Residential	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**0.065**	**0.065**	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**410**
Estimated Residential Customers	107,000	107,000	107,000
Estimated Appliance Saturation	100.00%	100.00%	100.00%
Market Eligibility	15.00%	15.00%	15.00%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	16,050	16,050	16,050
Total Demand or Energy Savings (kW or kWh)	**1,043**	**1,043**	**6,580,500**

Estimated Installation Cost per Unit	$143.36	
Estimated Annual Maintenance Cost per Unit	$0.11	
Measure Life	10	Years
Discount Rate	5.00%	

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)	Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	0.065	0.07	410	$5.75	$0.00	$31.83	$14.54
2008	0.065	0.07	410	$5.87	$0.00	$32.46	$14.83
2009	0.065	0.07	410	$5.98	$0.00	$33.11	$15.13
2010	0.065	0.07	410	$6.10	$0.00	$33.77	$15.43
2011	0.065	0.07	410	$6.22	$0.00	$34.45	$15.74
2012	0.065	0.07	410	$6.35	$0.00	$35.14	$16.06
2013	0.065	0.07	410	$6.48	$0.00	$35.84	$16.38
2014	0.065	0.07	410	$6.60	$0.00	$36.56	$16.71
2015	0.065	0.07	410	$6.74	$0.00	$37.29	$17.04
2016	0.065	0.07	410	$6.87	$0.00	$38.03	$17.38

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$143.36	$14.54	($128.82)	($128.82)
2008	$0.11	$14.83	$14.72	$14.02
2009	$0.11	$15.13	$15.02	$13.62
2010	$0.11	$15.43	$15.32	$13.23
2011	$0.11	$15.74	$15.63	$12.86
2012	$0.11	$16.06	$15.95	$12.50
2013	$0.11	$16.38	$16.27	$12.14
2014	$0.11	$16.71	$16.60	$11.80
2015	$0.11	$17.04	$16.93	$11.46
2016	$0.11	$17.38	$17.27	$11.13
Total	$144.35	$159.24	$14.89	($16.06)

Footnote #1
Footnote #2
Footnote #3
Footnote #4

Appendix C
Impact of DSM Options
Improved Home Loan Program for Furnace & AC Replacement

DSM Technology Residential	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**1.00**	**1.00**	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**500**
Estimated Residential Customers	107,000	107,000	107,000
Estimated Appliance Saturation	100.00%	100.00%	100.00%
Market Eligibility	5.80%	5.80%	5.80%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	6,206	6,206	6,206
Total Demand or Energy Savings (kW or kWh)	**6,206**	**6,206**	**3,103,000**

Estimated Installation Cost per Unit	$960.03	
Estimated Annual Maintenance Cost per Unit	$0.37	
Measure Life	20	Years
Discount Rate	5.00%	

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)		Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	1		1.00	500	$5.75	$0.00	$31.83	$38.91
2008	1		1.00	500	$5.87	$0.00	$32.46	$39.69
2009	1		1.00	500	$5.98	$0.00	$33.11	$40.48
2010	1		1.00	500	$6.10	$0.00	$33.77	$41.29
2011	1		1.00	500	$6.22	$0.00	$34.45	$42.12
2012	1		1.00	500	$6.35	$0.00	$35.14	$42.96
2013	1		1.00	500	$6.48	$0.00	$35.84	$43.82
2014	1		1.00	500	$6.60	$0.00	$36.56	$44.70
2015	1		1.00	500	$6.74	$0.00	$37.29	$45.59
2016	1		1.00	500	$6.87	$0.00	$38.03	$46.50

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$960.03	$38.91	($921.12)	($921.12)
2008	$0.37	$39.69	$39.32	$37.45
2009	$0.38	$40.48	$40.10	$36.37
2010	$0.39	$41.29	$40.90	$35.33
2011	$0.40	$42.12	$41.72	$34.32
2012	$0.41	$42.96	$42.55	$33.34
2013	$0.42	$43.82	$43.40	$32.39
2014	$0.43	$44.70	$44.27	$31.46
2015	$0.44	$45.59	$45.15	$30.56
2016	$0.45	$46.50	$46.05	$29.68
Total	$963.72	$426.06	($537.66)	($620.22)

Footnote #1
Footnote #2
Footnote #3
Footnote #4

Appendix C
Impact of DSM Options
Energy-Efficient New Home

DSM Technology Residential	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**0.80**	**0.80**	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**600**
Estimated Residential Customers	107,000	107,000	107,000
Estimated Appliance Saturation	3.00%	3.00%	3.00%
Market Eligibility	100.00%	100.00%	100.00%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	3,210	3,210	3,210
Total Demand or Energy Savings (kW or kWh)	**2,568**	**2,568**	**1,926,000**

Estimated Installation Cost per Unit	$762.25	
Estimated Annual Maintenance Cost per Unit	$0.72	
Measure Life	25	Years
Discount Rate	5.00%	

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)	Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	0.8	0.80	600	$5.75	$0.00	$31.83	$37.50
2008	0.8	0.80	600	$5.87	$0.00	$32.46	$38.24
2009	0.8	0.80	600	$5.98	$0.00	$33.11	$39.01
2010	0.8	0.80	600	$6.10	$0.00	$33.77	$39.79
2011	0.8	0.80	600	$6.22	$0.00	$34.45	$40.59
2012	0.8	0.80	600	$6.35	$0.00	$35.14	$41.40
2013	0.8	0.80	600	$6.48	$0.00	$35.84	$42.23
2014	0.8	0.80	600	$6.60	$0.00	$36.56	$43.07
2015	0.8	0.80	600	$6.74	$0.00	$37.29	$43.93
2016	0.8	0.80	600	$6.87	$0.00	$38.03	$44.81

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$762.25	$37.50	($724.75)	($724.75)
2008	$0.72	$38.24	$37.52	$35.73
2009	$0.74	$39.01	$38.27	$34.71
2010	$0.76	$39.79	$39.03	$33.72
2011	$0.78	$40.59	$39.81	$32.75
2012	$0.80	$41.40	$40.60	$31.81
2013	$0.82	$42.23	$41.41	$30.90
2014	$0.84	$43.07	$42.23	$30.01
2015	$0.87	$43.93	$43.06	$29.14
2016	$0.90	$44.81	$43.91	$28.30
Total	$769.48	$410.57	($358.91)	($437.66)

Footnote #1
Footnote #2
Footnote #3
Footnote #4

Appendix C
Impact of DSM Options
Energy-Efficient Existing Home

DSM Technology Residential	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**1.00**	**1.00**	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**800**
Estimated Residential Customers	107,000	107,000	107,000
Estimated Appliance Saturation	50.00%	50.00%	50.00%
Market Eligibility	8.00%	8.00%	8.00%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	4,280	4,280	4,280
Total Demand or Energy Savings (kW or kWh)	**4,280**	**4,280**	**3,424,000**

Estimated Installation Cost per Unit	$1,539.81	
Estimated Annual Maintenance Cost per Unit	$0.41	
Measure Life	20	Years
Discount Rate	5.00%	

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)	Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	1	1.00	800	$5.75	$0.00	$31.83	$48.46
2008	1	1.00	800	$5.87	$0.00	$32.46	$49.43
2009	1	1.00	800	$5.98	$0.00	$33.11	$50.42
2010	1	1.00	800	$6.10	$0.00	$33.77	$51.43
2011	1	1.00	800	$6.22	$0.00	$34.45	$52.45
2012	1	1.00	800	$6.35	$0.00	$35.14	$53.50
2013	1	1.00	800	$6.48	$0.00	$35.84	$54.57
2014	1	1.00	800	$6.60	$0.00	$36.56	$55.67
2015	1	1.00	800	$6.74	$0.00	$37.29	$56.78
2016	1	1.00	800	$6.87	$0.00	$38.03	$57.91

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$1,539.81	$48.46	($1,491.35)	($1,491.35)
2008	$0.41	$49.43	$49.02	$46.69
2009	$0.42	$50.42	$50.00	$45.35
2010	$0.43	$51.43	$51.00	$44.06
2011	$0.44	$52.45	$52.01	$42.79
2012	$0.45	$53.50	$53.05	$41.57
2013	$0.46	$54.57	$54.11	$40.38
2014	$0.47	$55.67	$55.20	$39.23
2015	$0.48	$56.78	$56.30	$38.11
2016	$0.49	$57.91	$57.42	$37.01
Total	$1,543.86	$530.62	($1,013.24)	($1,116.18)

Footnote #1
Footnote #2
Footnote #3
Footnote #4

Appendix C
Impact of DSM Options
Compact Fluorescent Lighting

DSM Technology Commercial	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**0.00**	**0.00**	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**219**
Estimated Customers	133,000	133,000	133,000
Estimated CF Lighting Saturation	100.00%	100.00%	100.00%
Market Eligibility	100.00%	100.00%	100.00%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	133,000	133,000	133,000
Total Demand or Energy Savings (kW or kWh)	**0**	**0**	**29,127,000**

Estimated Installation Cost per Unit	$5.05	
Estimated Annual Maintenance Cost per Unit	$0.02	
Measure Life	15	Years
Discount Rate	5.00%	

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)	Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	0.00	0.00	219	$5.75	$0.00	$31.83	$6.97
2008	0.00	0.00	219	$5.87	$0.00	$32.46	$7.11
2009	0.00	0.00	219	$5.98	$0.00	$33.11	$7.25
2010	0.00	0.00	219	$6.10	$0.00	$33.77	$7.40
2011	0.00	0.00	219	$6.22	$0.00	$34.45	$7.54
2012	0.00	0.00	219	$6.35	$0.00	$35.14	$7.70
2013	0.00	0.00	219	$6.48	$0.00	$35.84	$7.85
2014	0.00	0.00	219	$6.60	$0.00	$36.56	$8.01
2015	0.00	0.00	219	$6.74	$0.00	$37.29	$8.17
2016	0.00	0.00	219	$6.87	$0.00	$38.03	$8.33

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$5.05	$6.97	$1.92	$1.92
2008	$0.02	$7.11	$7.09	$6.75
2009	$0.02	$7.25	$7.23	$6.56
2010	$0.02	$7.40	$7.38	$6.38
2011	$0.02	$7.54	$7.52	$6.19
2012	$0.02	$7.70	$7.68	$6.02
2013	$0.02	$7.85	$7.83	$5.84
2014	$0.02	$8.01	$7.99	$5.68
2015	$0.02	$8.17	$8.15	$5.52
2016	$0.02	$8.33	$8.31	$5.36
Total	$5.23	$76.33	$71.10	$56.20

Footnote #1
Footnote #2
Footnote #3
Footnote #4

Appendix C
Impact of DSM Options
Commercial High-Efficiency Lighting

DSM Technology Commercial	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**4.00**	**4.00**	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**13000**
Estimated Commercial Customers	1,500	1,500	1,500
Estimated Appliance Saturation	100.00%	100.00%	100.00%
Market Eligibility	20.00%	20.00%	20.00%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	300	300	300
Total Demand or Energy Savings (kW or kWh)	**1,200**	**1,200**	**3,900,000**

Estimated Installation Cost per Unit	$3,306.32	
Estimated Annual Maintenance Cost per Unit	$14.92	
Measure Life	15	Years
Discount Rate	5.00%	

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)	Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	4.00	4.00	13000	$5.75	$0.00	$31.83	$505.73
2008	4.00	4.00	13000	$5.87	$0.00	$32.46	$515.84
2009	4.00	4.00	13000	$5.98	$0.00	$33.11	$526.16
2010	4.00	4.00	13000	$6.10	$0.00	$33.77	$536.68
2011	4.00	4.00	13000	$6.22	$0.00	$34.45	$547.41
2012	4.00	4.00	13000	$6.35	$0.00	$35.14	$558.36
2013	4.00	4.00	13000	$6.48	$0.00	$35.84	$569.53
2014	4.00	4.00	13000	$6.60	$0.00	$36.56	$580.92
2015	4.00	4.00	13000	$6.74	$0.00	$37.29	$592.54
2016	4.00	4.00	13000	$6.87	$0.00	$38.03	$604.39

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$3,306.32	$505.73	($2,800.59)	($2,800.59)
2008	$14.92	$515.84	$500.92	$477.07
2009	$15.37	$526.16	$510.79	$463.30
2010	$15.83	$536.68	$520.85	$449.93
2011	$16.30	$547.41	$531.11	$436.95
2012	$16.79	$558.36	$541.57	$424.33
2013	$17.29	$569.53	$552.24	$412.09
2014	$17.81	$580.92	$563.11	$400.19
2015	$18.34	$592.54	$574.20	$388.64
2016	$18.89	$604.39	$585.50	$377.42
Total	$3,457.86	$5,537.56	$2,079.70	$1,029.33

Footnote #1
Footnote #2
Footnote #3
Footnote #4

Appendix C
Impact of DSM Options
Commercial High-Efficiency Air Conditioners

DSM Technology Commercial	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**2.00**		
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**2500**
Estimated Commercial Customers	23,500	23,500	23,500
Estimated Appliance Saturation	100.00%	100.00%	100.00%
Market Eligibility	25.00%	25.00%	25.00%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	5,875	5,875	5,875
Total Demand or Energy Savings (kW or kWh)	**11,750**	**0**	**14,687,500**

Estimated Installation Cost per Unit	$1,215.05	
Estimated Annual Maintenance Cost per Unit	$0.33	
Measure Life	20	Years
Discount Rate	5.00%	

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)	Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Annual Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	2	0.00	2500	$5.75	$0.00	$31.83	$125.56
2008	2	0.00	2500	$5.87	$0.00	$32.46	$128.07
2009	2	0.00	2500	$5.98	$0.00	$33.11	$130.64
2010	2	0.00	2500	$6.10	$0.00	$33.77	$133.25
2011	2	0.00	2500	$6.22	$0.00	$34.45	$135.91
2012	2	0.00	2500	$6.35	$0.00	$35.14	$138.63
2013	2	0.00	2500	$6.48	$0.00	$35.84	$141.40
2014	2	0.00	2500	$6.60	$0.00	$36.56	$144.23
2015	2	0.00	2500	$6.74	$0.00	$37.29	$147.12
2016	2	0.00	2500	$6.87	$0.00	$38.03	$150.06

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$1,215.05	$125.56	($1,089.49)	($1,089.49)
2008	$0.33	$128.07	$127.74	$121.66
2009	$0.34	$130.64	$130.30	$118.19
2010	$0.35	$133.25	$132.90	$114.80
2011	$0.36	$135.91	$135.55	$111.52
2012	$0.37	$138.63	$138.26	$108.33
2013	$0.38	$141.40	$141.02	$105.23
2014	$0.39	$144.23	$143.84	$102.22
2015	$0.40	$147.12	$146.72	$99.31
2016	$0.41	$150.06	$149.65	$96.47
Total	$1,218.38	$1,374.87	$156.49	($111.77)

Footnote #1
Footnote #2
Footnote #3
Footnote #4

Appendix C
Impact of DSM Options
Commercial HVAC Efficiency Improvement Program

DSM Technology Commercial	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**5.00**	**5.00**	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**4380**
Estimated Commercial Customers	1,500	1,500	1,500
Estimated Appliance Saturation	100.00%	100.00%	100.00%
Market Eligibility	33.00%	33.00%	33.00%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	495	495	495
Total Demand or Energy Savings (kW or kWh)	**2,475**	**2,475**	**2,168,100**

Estimated Installation Cost per Unit $2,213.61
Estimated Annual Maintenance Cost per Unit $4.68
Measure Life 20 Years

Discount Rate 5.00%

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)	Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Annual Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	5	5	4380	$5.75	$0.00	$31.83	$254.39
2008	5	5	4380	$5.87	$0.00	$32.46	$259.48
2009	5	5	4380	$5.98	$0.00	$33.11	$264.67
2010	5	5	4380	$6.10	$0.00	$33.77	$269.96
2011	5	5	4380	$6.22	$0.00	$34.45	$275.36
2012	5	5	4380	$6.35	$0.00	$35.14	$280.87
2013	5	5	4380	$6.48	$0.00	$35.84	$286.49
2014	5	5	4380	$6.60	$0.00	$36.56	$292.22
2015	5	5	4380	$6.74	$0.00	$37.29	$298.06
2016	5	5	4380	$6.87	$0.00	$38.03	$304.02

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$2,213.61	$254.39	($1,959.22)	($1,959.22)
2008	$4.68	$259.48	$254.80	$242.67
2009	$4.82	$264.67	$259.85	$235.69
2010	$4.96	$269.96	$265.00	$228.92
2011	$5.11	$275.36	$270.25	$222.34
2012	$5.26	$280.87	$275.61	$215.95
2013	$5.42	$286.49	$281.07	$209.74
2014	$5.58	$292.22	$286.64	$203.71
2015	$5.75	$298.06	$292.31	$197.85
2016	$5.92	$304.02	$298.10	$192.16
Total	$2,261.11	$2,785.52	$524.41	($10.21)

Footnote #1
Footnote #2
Footnote #3
Footnote #4

Appendix C
Impact of DSM Options
Large Customer Customized Rebate Program

DSM Technology Commercial	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**5.00**	**5.00**	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**8750**
Estimated Commercial Customers	1,500	1,500	1,500
Estimated Appliance Saturation	100.00%	100.00%	100.00%
Market Eligibility	5.00%	5.00%	5.00%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	75	75	75
Total Demand or Energy Savings (kW or kWh)	**375**	**375**	**656,250**

Estimated Installation Cost per Unit	$3,587.65	
Estimated Annual Maintenance Cost per Unit	$46.37	
Measure Life	15	Years
Discount Rate	5.00%	

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)	Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Annual Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	5	5	8750	$5.75	$0.00	$31.83	$393.47
2008	5	5	8750	$5.87	$0.00	$32.46	$401.34
2009	5	5	8750	$5.98	$0.00	$33.11	$409.36
2010	5	5	8750	$6.10	$0.00	$33.77	$417.55
2011	5	5	8750	$6.22	$0.00	$34.45	$425.90
2012	5	5	8750	$6.35	$0.00	$35.14	$434.42
2013	5	5	8750	$6.48	$0.00	$35.84	$443.11
2014	5	5	8750	$6.60	$0.00	$36.56	$451.97
2015	5	5	8750	$6.74	$0.00	$37.29	$461.01
2016	5	5	8750	$6.87	$0.00	$38.03	$470.23

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$3,587.65	$393.47	($3,194.18)	($3,194.18)
2008	$46.37	$401.34	$354.97	$338.07
2009	$47.76	$409.36	$361.60	$327.98
2010	$49.19	$417.55	$368.36	$318.20
2011	$50.67	$425.90	$375.23	$308.70
2012	$52.19	$434.42	$382.23	$299.49
2013	$53.76	$443.11	$389.35	$290.54
2014	$55.37	$451.97	$396.60	$281.86
2015	$57.03	$461.01	$403.98	$273.43
2016	$58.74	$470.23	$411.49	$265.25
Total	$4,058.73	$4,308.36	$249.63	($490.66)

Footnote #1
Footnote #2
Footnote #3
Footnote #4

Appendix C
Impact of DSM Options
Interruptible Rates

DSM Technology Commercial	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**75.00**	**75.00**	
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**1500**
Estimated Commercial Customers	1,500	1,500	1,500
Estimated Appliance Saturation	100.00%	100.00%	100.00%
Market Eligibility	10.00%	10.00%	10.00%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	150	150	150
Total Demand or Energy Savings (kW or kWh)	**11,250**	**11,250**	**225,000**

Estimated Installation Cost per Unit	$1,332.19	
Estimated Annual Maintenance Cost per Unit	$447.73	
Measure Life	25	Years
Discount Rate	5.00%	

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)	Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Annual Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	75	75	1500	$5.75	$0.00	$31.83	$1,772.74
2008	75	75	1500	$5.87	$0.00	$32.46	$1,808.19
2009	75	75	1500	$5.98	$0.00	$33.11	$1,844.36
2010	75	75	1500	$6.10	$0.00	$33.77	$1,881.24
2011	75	75	1500	$6.22	$0.00	$34.45	$1,918.87
2012	75	75	1500	$6.35	$0.00	$35.14	$1,957.25
2013	75	75	1500	$6.48	$0.00	$35.84	$1,996.39
2014	75	75	1500	$6.60	$0.00	$36.56	$2,036.32
2015	75	75	1500	$6.74	$0.00	$37.29	$2,077.04
2016	75	75	1500	$6.87	$0.00	$38.03	$2,118.59

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$1,332.19	$1,772.74	$440.55	$440.55
2008	$447.73	$1,808.19	$1,360.46	$1,295.68
2009	$461.16	$1,844.36	$1,383.20	$1,254.60
2010	$474.99	$1,881.24	$1,406.25	$1,214.77
2011	$489.24	$1,918.87	$1,429.63	$1,176.16
2012	$503.92	$1,957.25	$1,453.33	$1,138.72
2013	$519.04	$1,996.39	$1,477.35	$1,102.42
2014	$534.61	$2,036.32	$1,501.71	$1,067.24
2015	$550.65	$2,077.04	$1,526.39	$1,033.12
2016	$567.17	$2,118.59	$1,551.42	$1,000.06
Total	$5,880.70	$19,410.99	$13,530.29	$10,723.32

Footnote #1
Footnote #2
Footnote #3
Footnote #4

Appendix C
Impact of DSM Options
Residential Tree Planting Program

DSM Technology Residential	Summer Demand	Winter Demand	Annual Energy
Rated Load (kW per Unit)			
Coincident Factor (%)			
Contribution to Peak kW			
Demand Savings (%)			
Controllable Load (kW per unit)	**0.25**		
Annual Energy Usage			
Energy Savings (%)			
Energy Savings (kWh per unit)			**111**
Estimated Residential Customers	107,000	107,000	107,000
Estimated Appliance Saturation	5.80%	5.80%	5.80%
Market Eligibility	85.00%	85.00%	85.00%
Feasibility	100.00%	100.00%	100.00%
Estimated Controllable Units	5,275	5,275	5,275
Total Demand or Energy Savings (kW or kWh)	**1319**	**0**	**585525**

Estimated Installation Cost per Unit	$170.55	
Estimated Annual Maintenance Cost per Unit	$0.11	
Measure Life	30	Years
Discount Rate	5.00%	

Avoided Cost	Summer Capacity Savings (kW/unit)	Winter Capacity Savings (kW/unit)	Annual Energy Savings (kWh/unit)	Summer Capacity Charge ($/kW-mon.)	Winter Capacity Charge ($/kW-mon.)	Annual Energy Charge ($/MWh)	Power Cost Savings ($/unit)
2007	0.25	0.00	111	$5.75	$0.00	$31.83	$9.28
2008	0.25	0.00	111	$5.87	$0.00	$32.46	$9.47
2009	0.25	0.00	111	$5.98	$0.00	$33.11	$9.66
2010	0.25	0.00	111	$6.10	$0.00	$33.77	$9.85
2011	0.25	0.00	111	$6.22	$0.00	$34.45	$10.05
2012	0.25	0.00	111	$6.35	$0.00	$35.14	$10.25
2013	0.25	0.00	111	$6.48	$0.00	$35.84	$10.45
2014	0.25	0.00	111	$6.60	$0.00	$36.56	$10.66
2015	0.25	0.00	111	$6.74	$0.00	$37.29	$10.88
2016	0.25	0.00	111	$6.87	$0.00	$38.03	$11.09

Annual Cash Flows	Program Costs ($/per Unit)	Power Cost Savings ($/per Unit)	Annual Savings/ (Costs) ($/per Unit)	Present Value ($/per Unit)
2007	$170.55	$9.28	($161.27)	($161.27)
2008	$0.11	$9.47	$9.36	$8.91
2009	$0.11	$9.66	$9.55	$8.66
2010	$0.11	$9.85	$9.74	$8.41
2011	$0.11	$10.05	$9.94	$8.18
2012	$0.11	$10.25	$10.14	$7.94
2013	$0.11	$10.45	$10.34	$7.72
2014	$0.11	$10.66	$10.55	$7.50
2015	$0.11	$10.88	$10.77	$7.29
2016	$0.11	$11.09	$10.98	$7.08
Total	$171.54	$101.64	($69.90)	($89.58)

Footnote #1
Footnote #2
Footnote #3
Footnote #4