



ASSESSMENT OF DEMAND RESPONSE AND ENERGY EFFICIENCY POTENTIAL

***Volume 2 Eastern Interconnection Analysis
Final***

**Report #1314
Prepared for Midwest ISO**

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EXECUTIVE SUMMARY

The Midwest ISO staff models future transmission capacity needs. As part of this effort, they need 20-year load forecasts that account for demand response (DR) and energy efficiency (EE) activities in the Midwest ISO region and for the Eastern Interconnection. In the past, Midwest ISO staff assumed a reduction in sales and peak of 1% per year to approximate savings from DR and EE programs. In light of all the DR and EE activity taking place across the nation, they initiated this study to develop better and defensible estimates of EE and DR for their forecast.

This primary objective of the study is to develop estimates of DR and EE savings for the Midwest ISO area and the Eastern Connection regions according to the taxonomy used to describe resources in the EGEAS model, which the Midwest ISO currently uses for transmission planning studies. Estimates for the Midwest ISO area are presented in Volume 1 of this report. Volume 2 describes the Eastern Interconnection less the Midwest ISO area.

ANALYSIS APPROACH

To estimate savings from DR and EE programs in the Eastern Interconnection, we used a variety of publicly-available sources of information, as well as the results of the analysis for the Midwest ISO region¹. A primary source for this study is A National Assessment of Demand Response Potential; Staff Report, Federal Energy Regulatory Commission, June 2009 (FERC Study).

The first step was to develop a forecast of system peak demand and annual electricity use for 2010 through 2030 for the ten Eastern Interconnection regions. We started with EIA Form 861 to capture the number of customers and electricity sales for 2008 (the most recent data available) at the state or entity level. The forecast was derived by applying the population growth forecast from the FERC Study. The peak demand forecast was derived by taking the per customer peak estimate by state from the FERC Study and multiplying it by the population. The energy growth forecast for each state was taken from the FERC Study and applied to the 2008 energy estimates.

The second step was to develop projections of DR savings. For this task, the FERC Study provided estimates for the participation rates and load reduction impact associated with DR programs. The utility programs were then grouped so that they could be analyzed in a format consistent with the Midwest ISO's planning model (EGEAS).

The third step was to develop projections of EE savings. The analysis approach applied program participation rates, savings per participant, and program budget per kWh saved that were developed for the Midwest ISO region to the baseline of the Eastern Interconnection.

Chapter 2 presents additional information about the analysis approach.

¹ A detailed account of the analysis for the Midwest ISO region is included in Volume 1 of this report. The Midwest ISO analysis used utility forecast and program information to develop the savings estimates by program type. Collecting utility-provided data on the load forecast and program details were beyond the scope of this project for the Eastern Interconnection analysis.

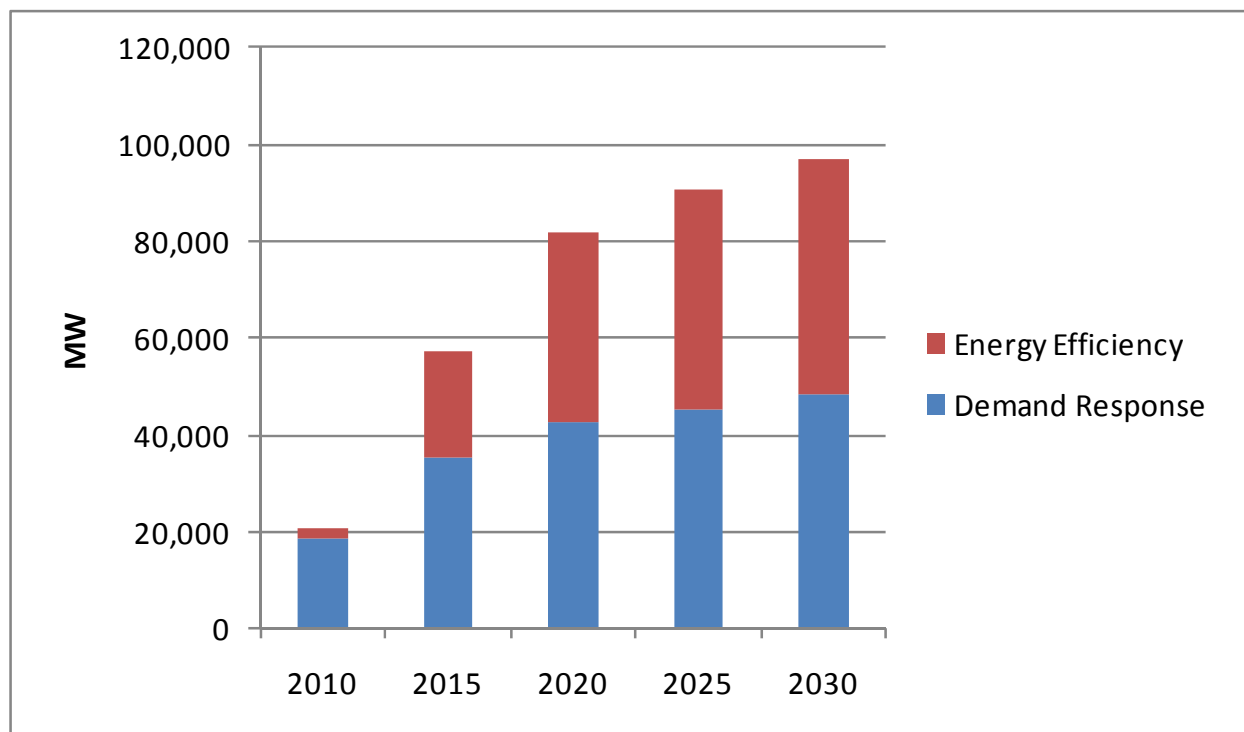
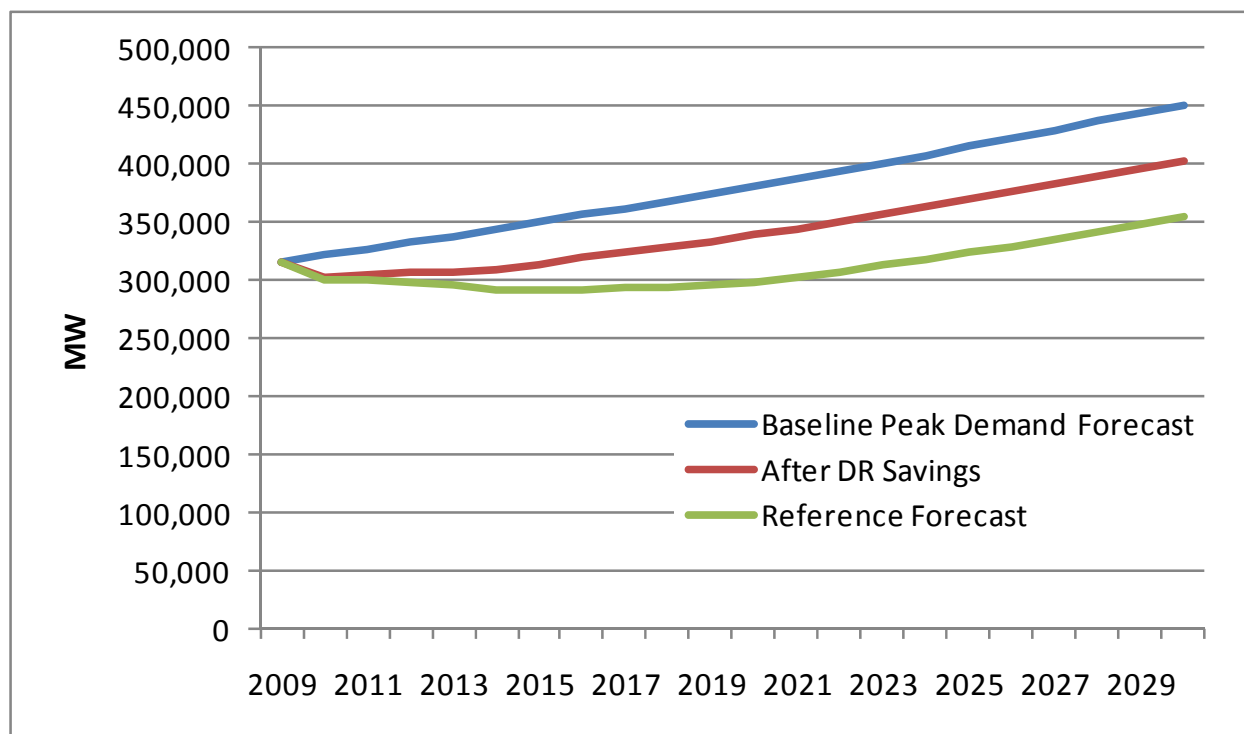
RESULTS

The baseline peak demand forecast, a forecast without future energy-efficiency and demand response programs, increases from 322 GW in 2010 to 452 GW in 2030. This is an increase of 40% and corresponds to an average annual growth rate of 1.7%. Table ES-1 and Figure ES-1 present the baseline forecast as well as peak demand savings from energy-efficiency and demand response programs. Figure ES-2 presents the baseline peak demand forecast, the forecast after savings from DR programs are applied and the reference forecast, which includes savings from DR and EE.

- In 2010, the savings are approximately 20.5 GW, or 6.4% of the baseline forecast.
- By 2020, the savings reach 96.8 GW, or 21.4% of the baseline forecast.
- Between 2020 and 2030, the savings continue to increase, but at the same rate as growth in the baseline forecast.
- By 2030, the savings offset 27% of the growth in peak demand.
- In 2010, demand response programs contribute about 90% of the savings. By 2020, the contribution from EE and DR programs is roughly equal and this continues to the end of the forecast.

Table ES-1 Summary of Eastern Interconnection Peak Demand Forecast and Program Savings 2010-2030

	2010	2015	2020	2025	2030
Demand Response Savings (MW)	18,584	35,517	42,399	45,357	48,564
Energy Efficiency Savings (MW)	1,953	21,936	39,630	45,567	48,200
Total Savings (MW)	20,537	57,452	82,029	90,924	96,764
Baseline Peak Demand Forecast (MW)	321,693	350,215	381,101	414,824	451,667
Total Savings as % of Baseline	6.4%	16.4%	21.5%	21.9%	21.4%
Reference Peak Demand Forecast (after savings from EE and DR are applied)	301,156	292,763	299,072	323,900	354,903

Figure ES-1 Eastern Interconnection Peak Demand Savings 2010-2030 (MW)**Figure ES-2 Eastern Interconnection Peak Demand Forecast 2009-2030 (MW)**

Energy-efficiency and demand response programs also produce savings in annual electricity use. While the energy savings from DR are very small compared to EE savings, they have been estimated for this study.

In 2010, the cumulative energy savings from EE and DR programs in the Eastern Interconnection are 10,992 GWh. This represents 0.6% of the baseline electricity forecast.

- Energy efficiency accounts for 9,948 GWh, which is 0.6% of the baseline energy forecast.
- Demand response accounts for 1,044 GWh, which is a negligible amount of the baseline energy forecast.

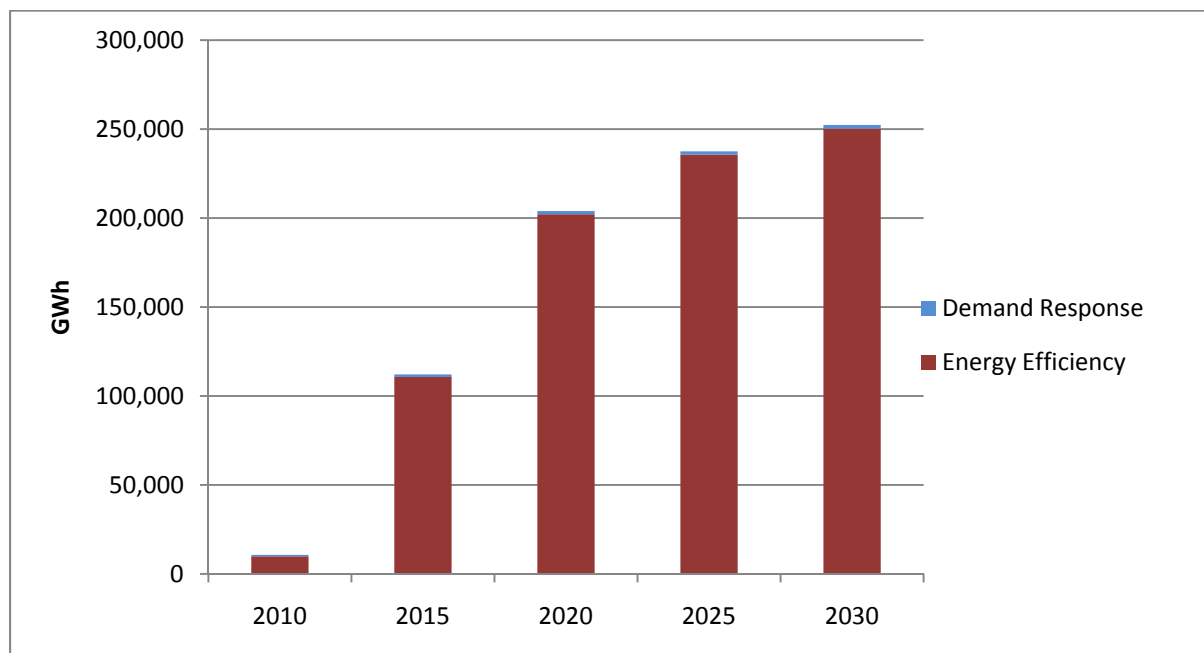
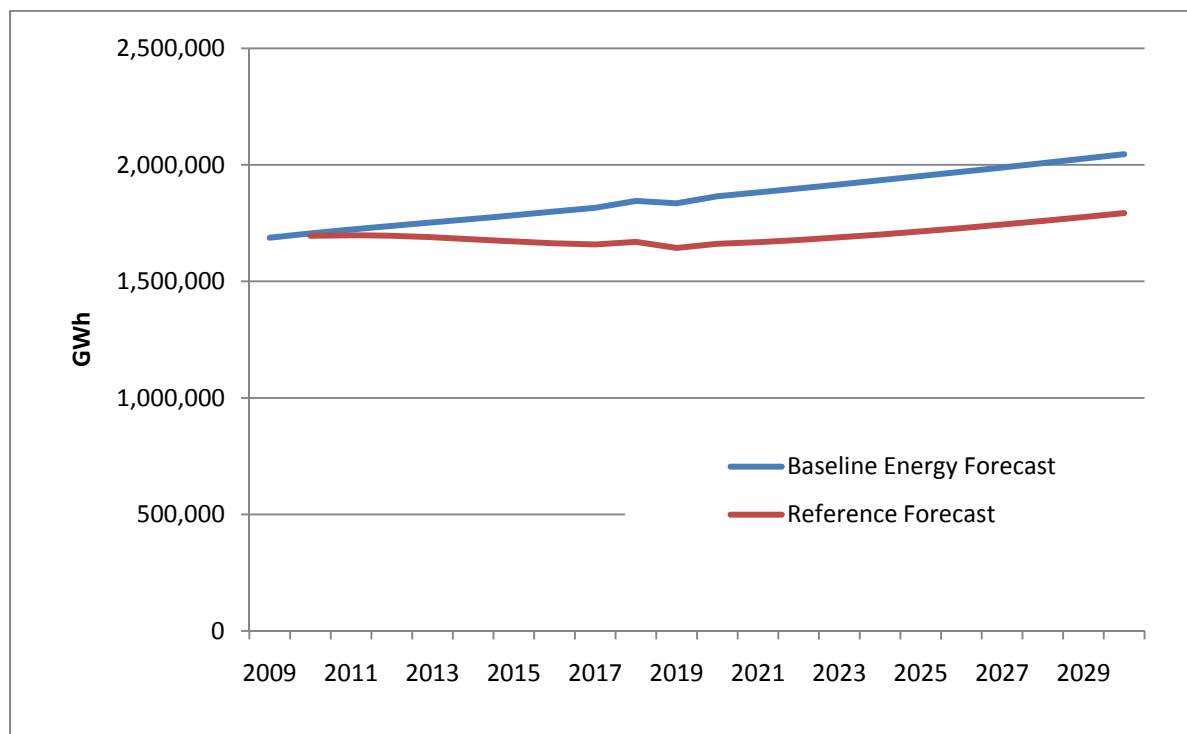
By 2030, the cumulative energy savings from EE and DR programs increases to over 253,600 GWh. This represents over 12% of the total energy baseline forecast.

- Energy efficiency accounts for 250,238 GWh, 12.2% of the total energy baseline.
- Demand response accounts for only 3,427 GWh, a negligible amount.
- By 2030, the cumulative savings offset 75% of the growth in annual electricity use.

Table ES-2 and Figure ES-3 present the annual electricity forecast and energy savings from EE and DR programs for selected years in the forecast. Figure ES-4 presents the baseline electricity use forecast together with the resulting forecasts after accounting for savings from EE and DR programs.

Table ES-2 Summary of Eastern Interconnection Energy Savings 2010-2030 (GWh)

	2010	2015	2020	2025	2030
Energy Efficiency Savings (GWh)	9,948	110,754	202,161	235,603	250,238
Demand Response Savings (GWh)	1,044	2,008	2,718	3,047	3,427
Total Savings (GWh)	10,992	112,762	204,879	238,650	253,665
Baseline Electricity Forecast (GWh)	1,706,012	1,783,693	1,865,241	1,951,393	2,045,265
Total Savings as % of Baseline	0.6%	6.3%	11.0%	12.2%	12.4%
Reference Energy Forecast (after savings from EE and DR are applied)	1,695,020	1,670,931	1,660,362	1,712,743	1,791,600

Figure ES-3 Eastern Interconnection Energy Savings 2010-2030 (GWh)**Figure ES-4 Eastern Interconnection Energy Savings 2010-2030 (GWh)**

Demand Response

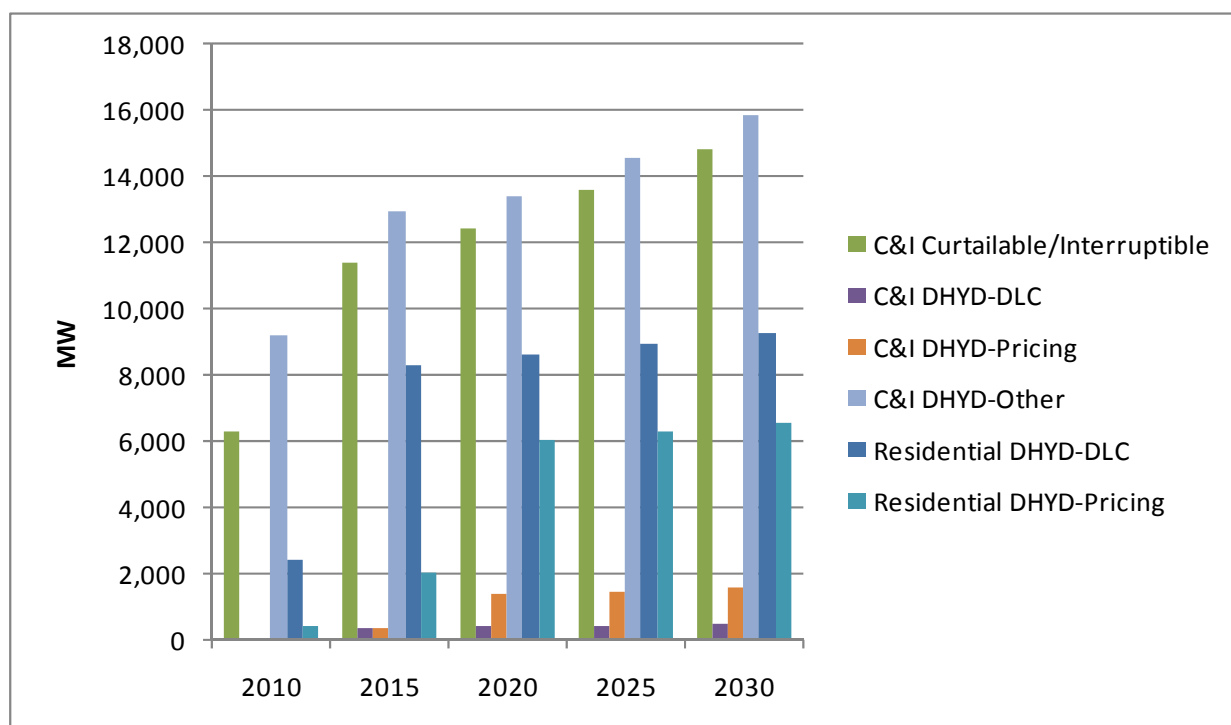
The demand response analysis for the Eastern Interconnection includes six program types:

- **Commercial and industrial (C&I) curtailable/interruptible tariffs.** Curtailable programs are those in which a customer commits to curtailing a certain amount of load whenever an event is called in exchange for lower energy price. Interruptible programs are programs in which a customer agrees to be interrupted in exchange for a fixed reduction in the monthly demand billing rate. If a customer does not reduce their load per their commitment, the utility may levy a penalty.
- **C&I direct load control (DLC).** These programs are where the C&I customer agrees to allow the utility to directly control equipment such as an air conditioner or hot water heater during events in exchange for a payment of some type (a flat fee per year or season and/or a per-event payment). A controlling device such as a switch or programmable thermostat is required
- **C&I dynamic pricing.** Dynamic pricing programs are structured so that customers have an incentive to reduce their usage during times of high energy demand or high wholesale energy prices. Under a critical peak pricing program, the customer pays a higher electricity rate during critical peak periods and pays a lower rate during off-peak periods. Often times, a critical peak pricing rate is combined with a time-of-use rate. Under a peak-time rebate program, the customer receives an incentive for reducing load during critical peak periods, and there is no penalty if the customer chooses not to participate.
- **C&I Other DR.** Other DR programs, available primarily to Medium and Large commercial and industrial customers, include programs such as capacity bidding, demand bidding, and other aggregator offerings, whether operated by an ISO, RTO, or a utility in an area without an ISO or RTO. This category also includes demand response being bid into capacity markets. Some of these programs are primarily price-triggered while others are triggered based on reliability conditions.
- **Residential DLC.** These programs are where the residential customer agrees to allow the utility to directly control equipment such as an air conditioner or hot water heater during events in exchange for a payment of some type (a flat fee per year or season and/or a per-event payment). A controlling device such as a switch or programmable thermostat is required.
- **Residential dynamic pricing.** Dynamic pricing programs are structured so that customers have an incentive to reduce their usage during times of high energy demand or high wholesale energy prices. Under a critical peak pricing program, the customer pays a higher electricity rate during critical peak periods and pays a lower rate during off-peak periods. Often times, a critical peak pricing rate is combined with a time-of-use rate. Under a peak-time rebate program, the customer receives an incentive for reducing load during critical peak periods, and there is no penalty if the customer chooses not to participate.

Table ES-3 and Figure ES-5 present DR savings by program type. In 2010, demand response programs account for 18,584 MW, which is 5.8% of the total peak baseline forecast. The majority of the savings come from C&I Other programs, which account for over half of the total impacts in 2010. In 2030, demand response programs account for 48,564 MW, which is 10.8% of the total peak baseline forecast. By 2030, the mix of savings changes somewhat to reflect the increase in Curtailable/Interruptible programs and a mild upswing in dynamic pricing.

Table ES-3 Demand Response Peak Demand Savings by Program Type (MW)

Program	2010	2015	2020	2025	2030
C&I Curtailable/Interruptible	6,315	11,435	12,459	13,579	14,806
C&I DHYD-DLC	74	395	422	450	481
C&I DHYD-Pricing	67	377	1,391	1,487	1,589
C&I DHYD-Other	9,234	12,956	13,425	14,575	15,830
Total C&I	15,689	25,164	27,698	30,091	32,706
Residential DHYD-DLC	2,447	8,311	8,626	8,954	9,298
Residential DHYD-Pricing	448	2,041	6,075	6,312	6,560
Total Residential	2,895	10,353	14,701	15,266	15,858
Total DR EI	18,584	35,517	42,399	45,357	48,564

Figure ES-5 Demand Response Peak Demand Impacts by Program Type (MW)

Summary of Demand Response by Region

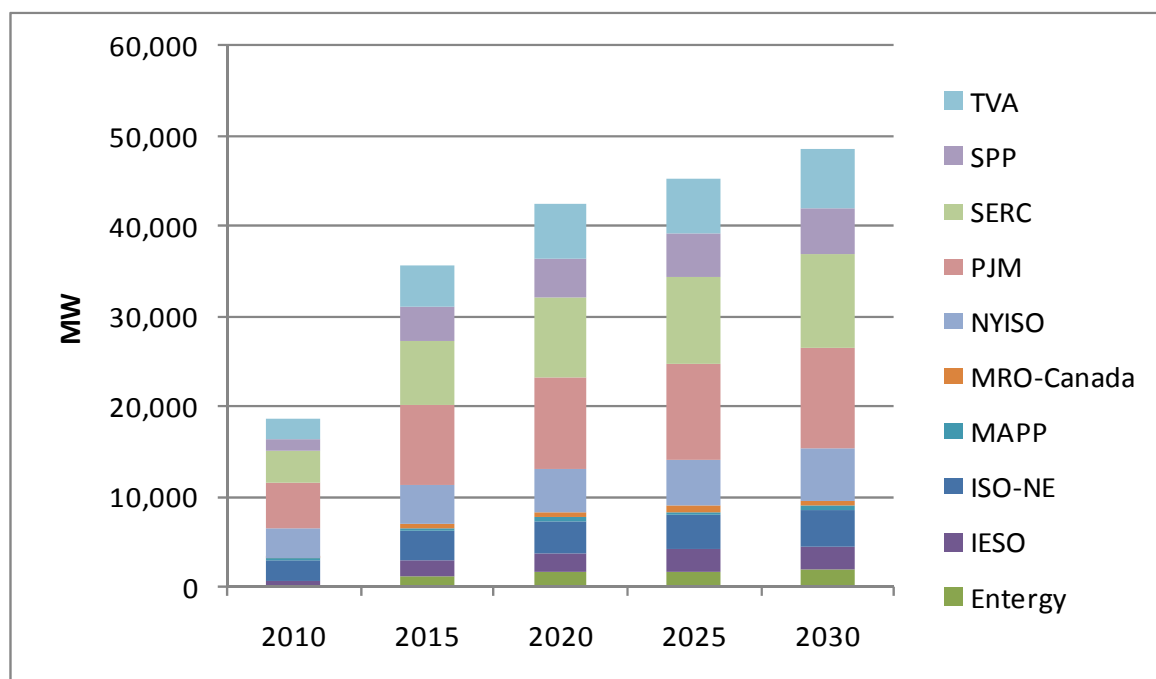
The regions vary considerably, reflecting the magnitude of their peak load and the differences in the current status of DR programs. Table ES-4 and Figure ES-6 present the results by region.

- In 2010, the PJM region had the highest impact from demand response with 4,972 MW, which is 6.7% of the regional peak baseline forecast. The MRO-Canada region has the lowest amount of savings with 78 MW, which is 1.3% of the regional peak baseline forecast. The NYISO region has the highest impact as a percentage of regional peak baseline forecast with 3,196 MW, which is 11.2% of the regional peak baseline forecast.
- In 2030, the PJM region again has the highest peak savings with 11,252 MW, which is 11.8% of the regional peak baseline forecast. The MAPP region has the lowest demand savings with 500 MW, or 11.0% of the regional peak baseline forecast. The ISO-NE and NYISO regions

lead the Eastern Interconnection regions for providing the largest impact as a percentage of regional peak baseline forecast with 13.9%.

Table ES-4 DR Peak Demand Savings by Region (MW)

	2010	2015	2020	2025	2030
Entergy					
DR Savings (MW)	302	1,292	1,696	1,814	1,941
Baseline Peak Demand Forecast (MW)	19,181	21,009	23,011	25,204	27,606
Savings as % of Baseline	1.6%	6.2%	7.4%	7.2%	7.0%
IESO					
DR Savings (MW)	372	1,716	2,078	2,338	2,631
Baseline Peak Demand Forecast (MW)	19,019	21,582	24,497	27,815	31,592
Savings as % of Baseline	2.0%	7.9%	8.5%	8.4%	8.3%
ISO-NE					
DR Savings (MW)	2,332	3,207	3,541	3,753	3,979
Baseline Peak Demand Forecast (MW)	21,611	23,171	24,853	26,669	28,628
Savings as % of Baseline	10.8%	13.8%	14.2%	14.1%	13.9%
MAPP					
DR Savings (MW)	249	397	452	475	500
Baseline Peak Demand Forecast (MW)	3,610	3,884	4,109	4,326	4,557
Savings as % of Baseline	6.9%	10.2%	11.0%	11.0%	11.0%
MRO-Canada					
DR Savings (MW)	78	412	516	541	565
Baseline Peak Demand Forecast (MW)	6,168	6,591	6,953	7,351	7,743
Savings as % of Baseline	1.3%	6.3%	7.4%	7.4%	7.3%
NYISO					
DR Savings (MW)	3,196	4,253	4,851	5,238	5,659
Baseline Peak Demand Forecast (MW)	28,517	31,193	34,120	37,322	40,824
Savings as % of Baseline	11.2%	13.6%	14.2%	14.0%	13.9%
PJM					
DR Savings (MW)	4,972	8,868	10,136	10,677	11,252
Baseline Peak Demand Forecast (MW)	74,144	79,005	84,146	89,617	95,442
Savings as % of Baseline	6.7%	11.2%	12.0%	11.9%	11.8%
SERC					
DR Savings (MW)	3,566	7,242	8,754	9,482	10,275
Baseline Peak Demand Forecast (MW)	61,276	67,277	73,867	81,102	89,047
Savings as % of Baseline	5.8%	10.8%	11.9%	11.7%	11.5%
SPP					
DR Savings (MW)	1,331	3,653	4,489	4,785	5,106
Baseline Peak Demand Forecast (MW)	37,204	40,615	44,282	48,267	52,620
Savings as % of Baseline	3.6%	9.0%	10.1%	9.9%	9.7%
TVA					
DR Savings (MW)	2,185	4,475	5,884	6,255	6,656
Baseline Peak Demand Forecast (MW)	50,964	55,888	61,263	67,151	73,608
Savings as % of Baseline	4.3%	8.0%	9.6%	9.3%	9.0%

Figure ES-6 DR Peak Demand Impacts by Region (MW)

Energy Efficiency

The analysis of energy efficiency for the Eastern Interconnection is based on results from the Midwest ISO analysis that is included in Volume 1. For the Midwest ISO analysis, we collected program data from utilities within the Midwest ISO region and assigned them to the following program type categories:

Residential

- Appliance incentives/rebates
- Appliance recycling
- Lighting initiatives
- Low income programs
- Multifamily programs
- New construction programs
- Whole home audit programs
- All other residential programs

Commercial and Industrial

- Lighting programs
- Prescriptive rebates
- Custom incentives
- New construction programs
- Retrocommissioning programs
- All other C&I programs

We further distinguished the utility programs as “low cost,” with cost less than \$1,000 per kW of peak demand savings and “high cost,” with cost greater than or equal to \$1,000 per kW of peak demand savings. The differentiation by cost is necessary for the EGEAS modeling. Assumptions about participation, growth and program impacts were made at the detailed program level and carried throughout the analysis.

Performing the energy-efficiency analysis for the Eastern Interconnection using the exact same approach as we used for the Midwest ISO was beyond the scope of this project as it would have involved contacting all the utilities in the Eastern Interconnection and analyzing their data. However, we leveraged the results of the Midwest ISO analysis by mapping each of the Eastern Interconnection regions to a representative Midwest ISO region. We made some modifications to account for differences in weather and/or regulatory climate so the mapping was done at a

state/province level². Table ES-5 shows how the Eastern Interconnection regions were mapped to the Midwest ISO regions:

Table ES-5 Mapping of Eastern Interconnection Region to Midwest ISO Region

Eastern Interconnection State/Province	Included ISO/RTO Region(s)	Mapped Midwest ISO Region
AL	SERC, TVA	East (Modified)
AR	Entergy, SPP	East
CT	ISO-NE	West (Modified)
DC	PJM	Central
DE	PJM	Central
GA	SERC	East (Modified)
IL	PJM	Central
IN	PJM	Central
KS	SPP	East
KY	PJM, TVA	East
LA	Entergy, SPP	East (Modified)
MA	ISO-NE	West (Modified)
Manitoba, Canada	MRO-Canada	East
MD	PJM	Central
ME	ISO-NE	West (Modified)
MI	PJM	Central
MO	SPP, TVA	Central
MS	Entergy, SERC, TVA	East (Modified)
NC	SERC, TVA	Central
ND	MAPP	East
NE	SPP	East
NH	ISO-NE	West (Modified)
NJ	PJM	Central
NM	SPP	Central (Modified)
NY	NYISO	West (Modified)
OH	PJM	Central
OK	SPP	Central
Ontario, Canada	IESO	West (Modified)
PA	PJM	Central
RI	ISO-NE	West (Modified)
SC	SERC	East (Modified)
SD	MAPP	East
Saskatchewan, Canada	MRO-Canada	East
TN	Entergy, TVA	East
TX	Entergy, SPP	Central (Modified)
VA	PJM	Central
VT	ISO-NE	West (Modified)
WV	PJM	East

Table ES-6 and Figure ES-7 present the cumulative savings from EE programs for selected forecast years in terms of the EGEAS blocks. Throughout the forecast period, more than three-fourths of the savings come from the low-cost programs.

- In 2010, energy efficiency programs account for 9,948 GWh, which is 0.6% of the total energy baseline forecast. The majority of the savings come from the commercial and

² Chapter 2 provides details on the analysis approach.

industrial sector programs, accounting for almost two-thirds of the total energy impacts in 2010.

- In 2030, energy efficiency programs account for 250,238 GWh, which is 12.2% of the total energy baseline forecast. By 2030, most of the energy savings (69%) still come from the commercial and industrial sector.

Table ES-6 Cumulative Energy Efficiency Savings by Program Type (GWh)

EGEAS Block	2010	2015	2020	2025	2030
Residential Low Cost	3,040	30,889	54,030	57,241	58,584
Residential High Cost	712	8,809	14,997	16,939	17,910
Total Residential	3,752	39,698	69,027	74,180	76,494
C&I Low Cost	4,640	55,398	105,521	128,355	137,989
C&I High Cost	1,556	15,658	27,613	33,068	35,755
Total C&I	6,196	71,056	133,134	161,423	173,744
Total EE for EI	9,948	110,754	202,161	235,603	250,238

Figure ES-7 Cumulative Energy Efficiency Savings by Program Type (GWh)

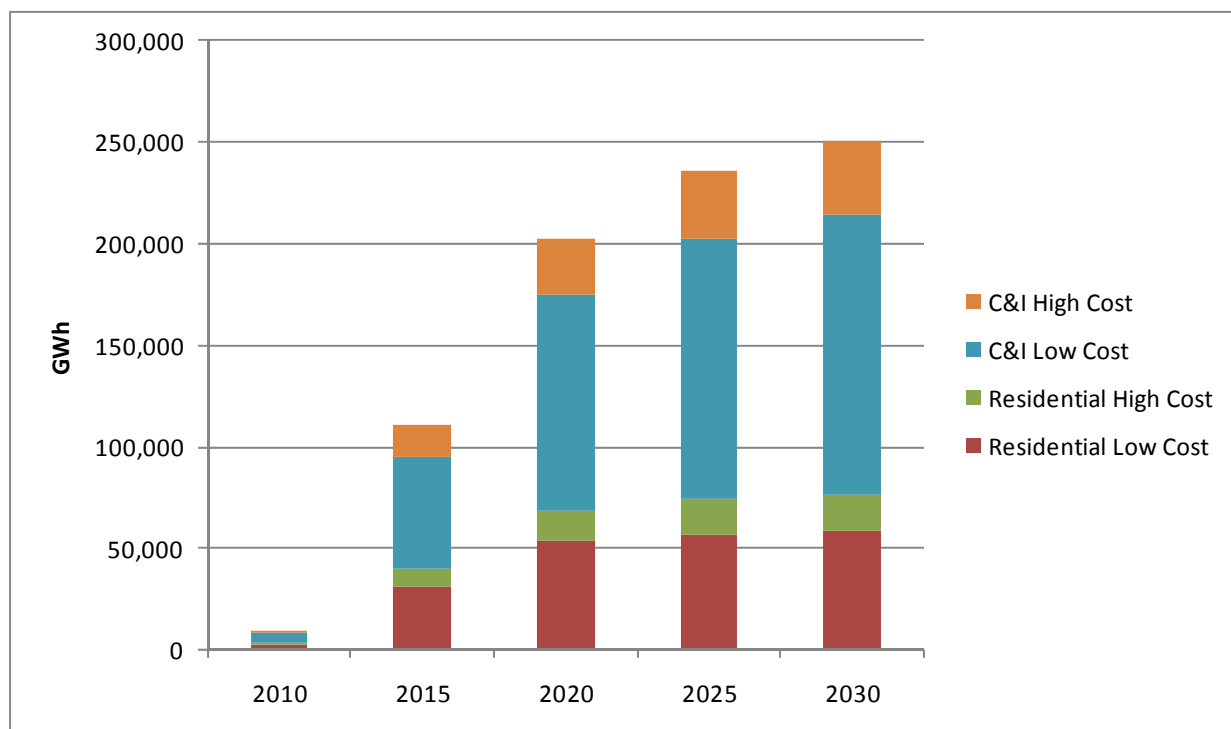


Table ES-7 through Table ES-10 present results by block and program type. Among the residential low-cost programs shown in Table ES-7:

- Appliance incentives/rebate programs provide the largest savings throughout the forecast period.
- Lighting initiatives are strong through 2015, prior to the effect of the lighting standards in the Energy Information and Security Act (EISA) which are fully in effect by 2014.
- The highest growth in savings is in multi-family programs.

Table ES-7 Cumulative EE Savings by Residential Low-Cost Program Type (GWh)

Detailed Program Type	2010	2015	2020	2025	2030
Appliance incentives/rebates	1,844	17,214	30,705	30,705	30,705
Appliance recycling	102	1,341	2,379	3,015	3,404
Lighting initiatives	569	2,947	3,997	4,004	4,004
Low income programs	31	520	813	885	903
Multifamily programs	272	5,891	10,276	11,349	11,614
New construction programs	35	267	458	576	648
Whole home audit programs	180	2,622	5,241	6,517	7,105
All other residential programs	7	87	161	190	200
Total for Residential Low-Cost	3,040	30,889	54,030	57,241	58,584

Among the residential high-cost programs shown in Table ES-8:

- Appliance incentives/rebate programs provide the largest savings throughout most of the forecast period.
- Appliance recycling and low-income programs show the strongest growth and by 2030 their cumulative savings exceed appliance incentives/rebates.

Table ES-8 Cumulative EE Savings by Residential High Cost Program Type (GWh)

Detailed Program Type	2010	2015	2020	2025	2030
Appliance incentives/rebates	330	2,516	4,266	4,266	4,266
Appliance recycling	99	2,048	3,782	4,845	5,496
Lighting initiatives	47	191	198	198	198
Low income programs	144	2,884	4,559	4,972	5,073
Multifamily programs	29	309	509	558	570
New construction programs	22	213	379	481	544
Whole home audit programs	34	602	1,223	1,525	1,665
All other residential programs	6	47	81	94	98
Total Projected Energy Reduction	712	8,809	14,997	16,939	17,910

Among the C&I low cost programs shown in Table ES-9:

- Prescriptive rebates account for about half the total savings in 2010 and about 35% of the savings in 2030.
- Lighting and retrocommissioning programs show the highest growth.

Table ES-9 Cumulative EE Savings by C&I Low Cost Program Type (GWh)

Detailed Program Type	2010	2015	2020	2025	2030
Lighting programs	774	10,683	25,440	33,280	36,017
Prescriptive rebates	2,389	23,381	41,516	47,862	50,084
Custom incentives	921	14,148	25,086	30,223	32,637
New construction programs	186	1,450	3,040	4,462	5,648
Retrocommissioning programs	197	3,880	6,376	7,003	7,160
All other C&I programs	172	1,856	4,063	5,525	6,442
Total Projected Energy Reduction	4,640	55,398	105,521	128,355	137,989

Among the C&I high cost programs shown in Table ES-10:

- Prescriptive rebates account for almost half the total savings in 2010 and about 40% of the savings in 2030.
- New construction and custom incentives programs show the highest growth.

Table ES-10 Cumulative EE Savings by C&I High Cost Program Type (GWh)

Detailed Program Type	2010	2015	2020	2025	2030
Lighting programs	51	394	835	1,073	1,157
Prescriptive rebates	750	6,532	11,302	12,977	13,565
Custom incentives	259	4,418	7,865	9,502	10,278
New construction programs	44	532	1,299	1,976	2,533
Retrocommissioning programs	222	1,938	2,964	3,226	3,292
All other C&I programs	231	1,844	3,347	4,315	4,930
Total Projected Energy Reduction	1,556	15,658	27,613	33,068	35,755

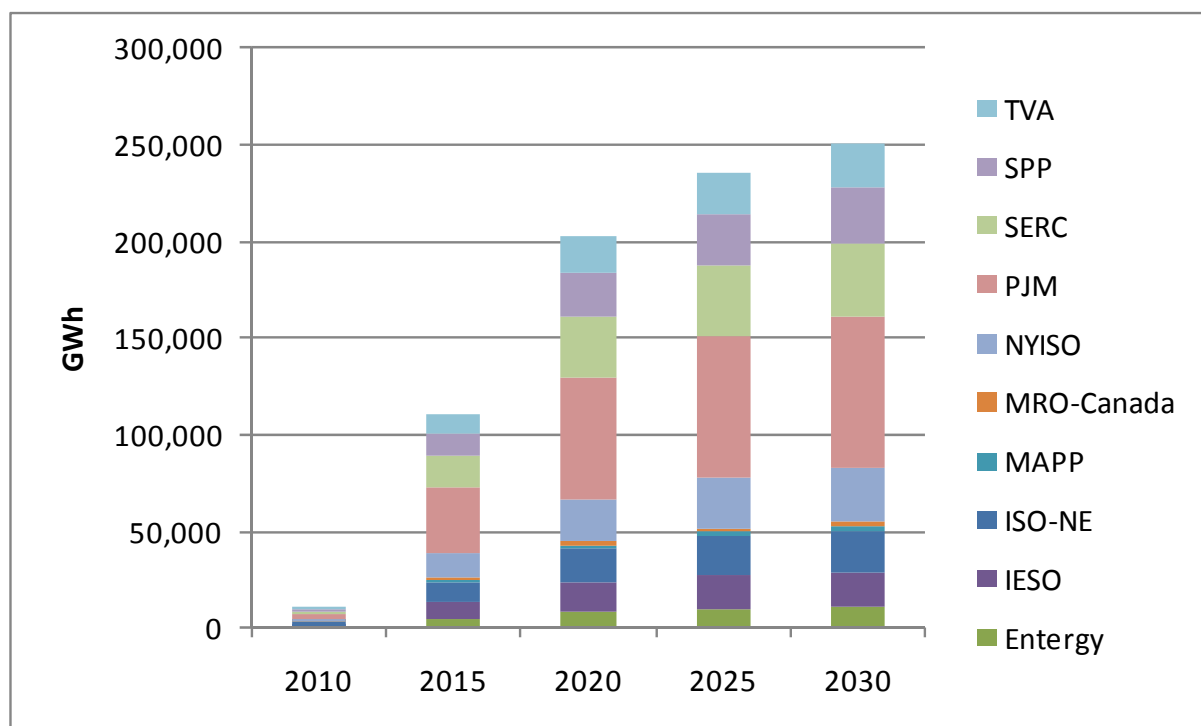
Summary of Energy Efficiency for Eastern Interconnection by Region

The regions vary considerably, reflecting the magnitude of their baseline energy and the differences in the current status of EE programs. Table ES-11 and Figure ES-8 show results by region.

- In 2010, the PJM region had the highest impact from energy efficiency with 2,567 GWh, which is 0.5% of the regional energy baseline forecast. The MAPP region has the lowest amount of savings with 49 GWh, which is 0.5% of the regional energy baseline forecast. The ISO-NE and NYISO regions have the largest impact compared to its regional baseline forecast with 1.2%.
- By 2030, the PJM region again has the highest impact from energy efficiency with 77,746 GWh, or 14.6% of the regional energy baseline forecast. The MAPP region contributes the least cumulative energy savings in 2030 with 2,073 GWh, however, this accounts for 15.6% of the regional energy baseline forecast. The ISO-NE region contributes the most in relation to its regional baseline energy forecast with 15.8%.

Table ES-11 EE Energy Savings by Region (GWh)

	2010	2015	2020	2025	2030
Entergy					
EE Savings (GWh)	280	4,436	8,553	9,971	10,543
Baseline Sales Forecast (GWh)	102,576	107,687	113,073	118,752	124,739
Savings as % of Baseline	0.3%	4.1%	7.6%	8.4%	8.5%
IESO					
EE Savings (GWh)	1,183	8,555	14,615	17,054	18,301
Baseline Sales Forecast (GWh)	135,821	140,570	145,831	151,631	158,002
Savings as % of Baseline	0.9%	6.1%	10.0%	11.2%	11.6%
ISO-NE					
EE Savings (GWh)	1,511	10,630	17,765	20,506	21,829
Baseline Sales Forecast (GWh)	123,827	127,200	130,757	134,506	138,457
Savings as % of Baseline	1.2%	8.4%	13.6%	15.2%	15.8%
MAPP					
EE Savings (GWh)	49	840	1,653	1,956	2,073
Baseline Sales Forecast (GWh)	9,783	10,706	11,545	12,415	13,307
Savings as % of Baseline	0.5%	7.8%	14.3%	15.8%	15.6%
MRO-Canada					
EE Savings (GWh)	67	1,097	2,114	2,447	2,574
Baseline Sales Forecast (GWh)	16,781	18,691	20,916	23,513	26,549
Savings as % of Baseline	0.4%	5.9%	10.1%	10.4%	9.7%
NYISO					
EE Savings (GWh)	1,807	12,970	22,030	25,732	27,590
Baseline Sales Forecast (GWh)	145,177	155,802	167,213	179,469	192,634
Savings as % of Baseline	1.2%	8.3%	13.2%	14.3%	14.3%
PJM					
EE Savings (GWh)	2,567	34,305	62,939	73,352	77,746
Baseline Sales Forecast (GWh)	467,594	483,603	499,186	515,029	533,921
Savings as % of Baseline	0.5%	7.1%	12.6%	14.2%	14.6%
SERC					
EE Savings (GWh)	1,061	16,276	31,213	36,552	38,777
Baseline Sales Forecast (GWh)	316,180	333,940	352,773	372,747	393,934
Savings as % of Baseline	0.3%	4.9%	8.8%	9.8%	9.8%
SPP					
EE Savings (GWh)	821	11,871	22,426	26,382	28,035
Baseline Sales Forecast (GWh)	184,858	193,026	201,855	211,122	220,854
Savings as % of Baseline	0.4%	6.1%	11.1%	12.5%	12.7%
TVA					
EE Savings (GWh)	602	9,775	18,853	21,651	22,771
Baseline Sales Forecast (GWh)	203,413	212,468	222,092	232,209	242,870
Savings as % of Baseline	0.3%	4.6%	8.5%	9.3%	9.4%

Figure ES-8 Energy Impacts from EE by Region (GWh), 2010 -2030

SCENARIO ANALYSIS

In addition to developing a reference forecast, we also performed scenario analysis. We used four scenarios that the Midwest ISO has developed as part of its Cost Allocation and Regional Planning (CARP) and Planning Advisory Committee (PAC) activities. Midwest ISO staff provided the verbal descriptions of each scenario from the Midwest ISO Transmission Expansion Plan 2010 (MTEP 10)³, as well as the spreadsheet of values assigned to each of the uncertainty variables⁴. Using these values, Midwest ISO staff also developed an electricity price forecast for each scenario⁵. We describe the four scenarios briefly below:

1. **S2: CARP Federal RPS Future (S2 RPS).** This scenario aligns with Midwest ISO's S2: CARP Federal RPS Future. This scenario requires that 20% of the energy consumption in the Eastern Interconnect come from wind by 2025. To model this, wind generation will begin to be forced into the models starting in 2012, accounting for the two-year lead time assumed for generation. Capacity factors for existing wind generators are taken from the NREL dataset while future wind units vary regionally from 35%-45%. Solar is modeled with a 10% annual capacity factor. Hydro and biomass are modeled with 50% annual capacity factors. State mandates are held true to the Business as Usual Future and any additional renewable energy is met with wind to satisfy the 20% renewable energy requirement. All wind is sited onshore. Midwest ISO assumes that electricity prices increase 23% from \$8.52/MWh in 2010 to \$10.45/MWh in 2025 in this scenario.
2. **S10: PAC Carbon Future – Carbon Cap with Nuclear (S10 Carbon Cap).** This scenario aligns with the Midwest ISO PAC's S10: PAC Carbon Future – Carbon Cap and Trade with Nuclear. This scenario embodies a declining cap on future CO₂ emissions. The carbon cap is modeled after the Waxman-Markey bill, which has an 83% reduction of CO₂ emissions from a 2005 baseline by the year 2050. That target is achieved through a linear reduction from 2010 to 2050 with mid-point goals of 3% reduction in 2012, 17%

³ Appendix F-3 of Midwest ISO Transmission Expansion Plan 2010: Future Scenarios Rate Impact Methodology (File: MTEP10_Appendix_F3_Rate_Impacts_rev4_draft_08262010)

⁴ MTEP 10 Futures 3-18-10.xls

⁵ Price Forecasts_MISO Scenarios_Rev1.xls provided by Wah Sing Ng, Ng Planning

reduction in 2020 and 42% reduction in 2030. This future deploys uneconomic coal retirements, oldest and highest heat-rate coal units are retired first, and also IGCC with sequestration and CC with sequestration technologies do not mature fast enough to become an option within the study period. Midwest ISO assumes that electricity prices increase 30% from \$8.52/MWh in 2010 to \$11.08/MWh in 2025 in this scenario. Midwest ISO also assumes that the demand growth rate decreases from .75% in the reference case to .3% under this scenario. Midwest ISO assumes that the energy growth rate also decreases from 1% in the reference case to .3%.

3. **S1: CARP Business as Usual with High Growth Rate for Demand and Energy (S1 High Growth).** This scenario is considered the status quo future, except with a quick recovery from the economic downturn in demand and energy projections. This future models the power system as it exists today with reference case values and trends, with the exception of demand and energy growth rates. These growth rates are based on recent historical data and assume that existing standards for resource adequacy, renewable mandates, and environmental legislation will remain unchanged. Renewable Portfolio Standard (RPS) requirements vary by state, and have many potential resources that can apply. RPS requirements will be met with the percent breakdown defined for each state from the CARP negotiators. Midwest ISO assumes that electricity prices only increase 6% from \$8.52/MWh in 2010 to \$9.02/MWh in 2025 in this scenario. Midwest ISO also assumes that the demand growth rate increases from .75% in the reference case to 1.6% under this scenario. Midwest ISO assumes that the energy growth rate also increases – from 1% in the reference case to 2.19%.
4. **S4: CARP Federal RPS + Carbon Cap + Smart Grid + Electric Cars (S4 Ultra Green).** This final scenario aligns with the Midwest ISO's S4: CARP Federal RPS, Carbon Cap and Trade, Smart Grid and Electric Cars. This scenario includes several elements of the previous three scenarios. It includes a federal RPS, a carbon cap and trade, smart grid and electric vehicles. The RPS is modeled the same way as in the S2 RPS scenario and the carbon cap legislation is modeled the same way as in S10 Carbon Cap. The effect of the smart grid is modeled within the demand growth rate. It is assumed that an increased penetration of smart grid will lower the overall growth of demand. The effect of the electric vehicles is modeled within the energy growth rate. Electric vehicles are assumed to increase off-peak energy usage and as such increase the overall energy growth rate. This scenario also causes a change to the load shape. In this scenario, Midwest ISO assumes that electricity prices increase 53% from \$8.52/MWh in 2010 to \$13.07/MWh in 2025. The changes in demand and energy growth rates are the same as under S10 Carbon Cap, which assumes that the demand growth rate decreases from .75% in the reference case to .3% and that the energy growth rate decreases from 1% in the reference case to .3%.

Using this information as a starting point, we developed a set of modeling assumptions for each scenario. Chapter 4 presents the detailed modeling assumptions and the results. We provide the summary results below.

Scenario Results for Peak Demand

Table ES-12 shows the effect the changes to the key assumptions have on the peak demand savings from EE and DR programs for each of the scenarios throughout the Eastern Interconnect. The S4 Ultra Green scenario achieves the most peak demand savings due to the effect of RPS, carbon cap legislation, smart grid and extremely high electricity prices. Table ES-13 shows the effect the changes to the key assumptions have on the peak demand savings from EE programs only and Table ES-13 shows the effect from DR programs only.

Table ES-12 Peak Demand Savings from EE and DR Programs by Scenario (MW)

	2010	2015	2020	2025	2030
Reference Case	20,537	57,452	82,029	90,924	96,764
S2 RPS	28,084	50,169	59,199	63,891	68,477
S10 Carbon Cap	18,285	38,055	50,412	52,619	55,127
S1 High Growth	17,613	37,253	47,797	51,300	55,120
S4 Ultra Green	37,323	91,656	124,580	130,611	135,451

Table ES-13 Peak Demand Savings from EE Programs Only by Scenario (MW)

	2010	2015	2020	2025	2030
Reference Case	1,953	21,936	39,630	45,567	48,200
S2 RPS	2,064	23,878	43,807	50,715	53,868
S10 Carbon Cap	2,102	24,457	45,052	52,252	55,551
S1 High Growth	1,948	23,161	43,326	50,568	53,858
S4 Ultra Green	2,102	25,141	47,170	55,160	58,876

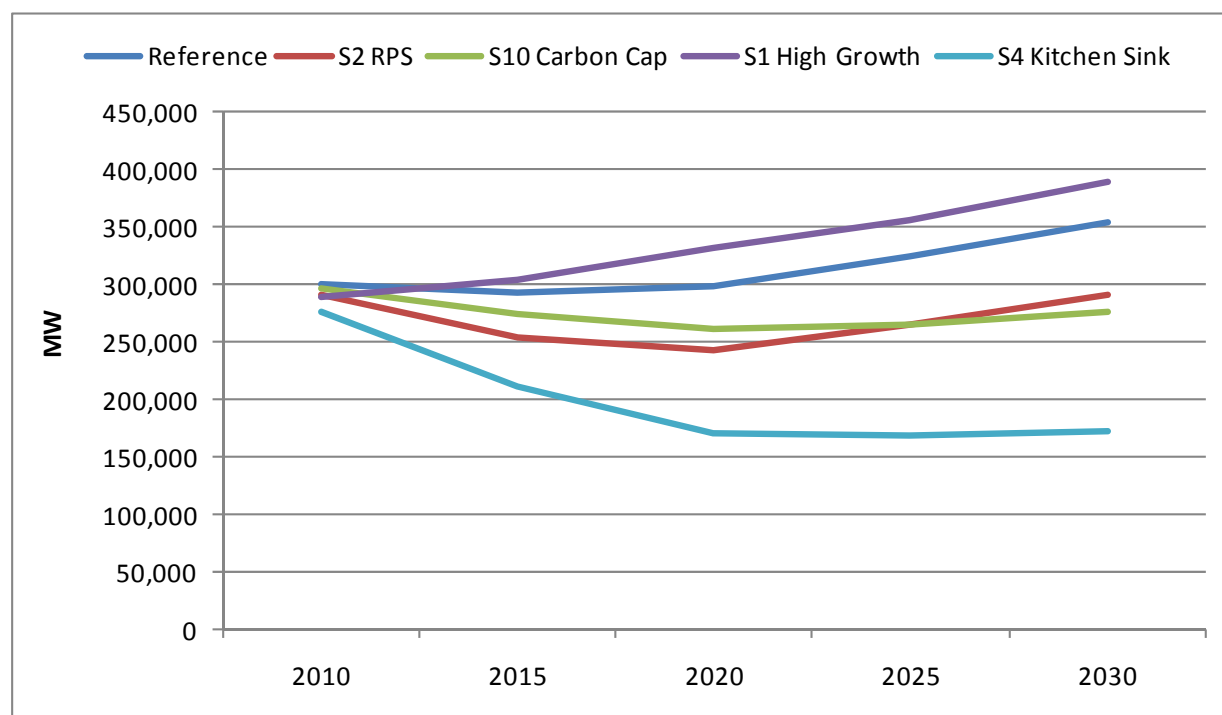
Table ES-14 Peak Demand Savings from DR Programs Only by Scenario (MW)

	2010	2015	2020	2025	2030
Reference Case	18,584	35,517	42,399	45,357	48,564
S2 RPS	28,084	50,169	59,199	63,891	68,477
S10 Carbon Cap	18,285	38,055	50,412	52,619	55,127
S1 High Growth	17,613	37,253	47,797	51,300	55,120
S4 Ultra Green	37,323	91,656	124,580	130,611	135,451

Table ES-15 and Figure ES-9 show the peak demand forecast for each scenario after the demand savings from EE and DR programs are applied. With the exception of S1 High Growth, the scenarios result in peak demand forecasts that are at or below the 2010 peak demand.

Table ES-15 Peak Demand Forecasts after EE and DR Program Savings by Scenario (MW)

	2010	2015	2020	2025	2030	% Increase (2010-30)	Average Annual Growth (%)
Reference	301,156	292,763	299,072	323,900	354,903	17.8%	0.8%
S2 RPS	290,904	254,619	242,954	265,995	292,208	0.4%	0.0%
S10 Carbon Cap	297,548	274,050	261,256	265,603	276,026	-7.2%	-0.4%
S1 High Growth	289,681	304,495	331,612	356,561	388,704	34.2%	1.5%
S4 Ultra Green	276,548	211,887	170,450	169,904	172,029	-37.8%	-2.4%

Figure ES-9 Forecasts of Peak Demand after EE and DR Program Savings

Scenario Results for Energy

Table ES-16 shows the effect the changes to the key assumptions have on the energy savings from EE programs for each of the scenarios. The S4 Ultra Green scenario achieves the most energy savings due to the impact of RPS, carbon cap legislation, smart grid and extremely high electricity prices.

Table ES-16 Energy Savings from EE Programs by Scenario (GWh)

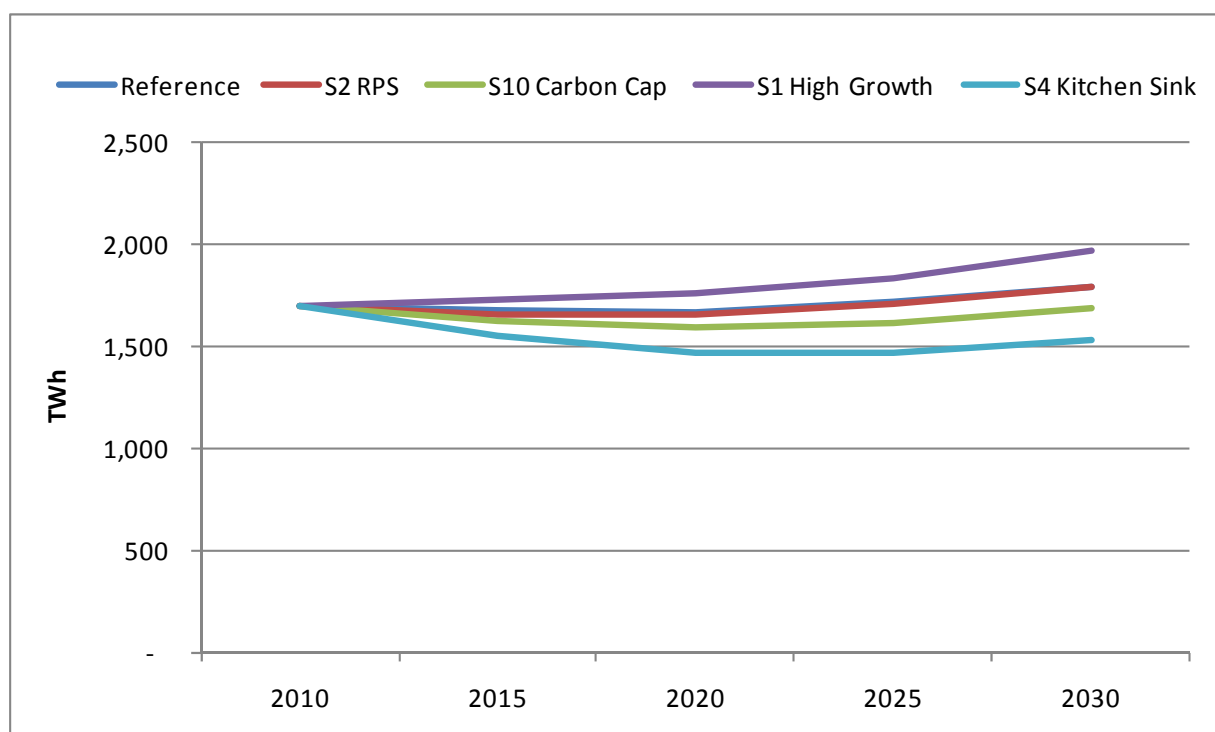
Baseline Demand	2010	2015	2020	2025	2030
Reference	9,948	110,754	202,161	235,603	250,238
S2 RPS	10,422	120,097	222,686	261,462	278,973
S10 Carbon Cap	10,620	123,066	229,183	269,665	288,009
S1 High Growth	9,816	116,670	221,138	261,902	280,217
S4 Ultra Green	10,620	126,556	240,235	285,278	306,000

Table ES 17 and Figure ES-10 show the energy forecast after the savings from EE programs are applied. Please note that the Reference forecast and the S2 RPS forecasts are nearly the same. The S10 Carbon Cap and S4 Ultra Green scenarios result in declining electricity use for the first ten years of the forecast and then a slight ramping up.

Table ES 17 Energy Forecasts by Scenario (GWh)

	2010	2015	2020	2025	2030	% Increase (2010-30)	Average Annual Growth (%)
Reference	1,696,064	1,672,939	1,663,080	1,715,790	1,795,027	5.8%	0.3%
S2 RPS	1,695,589	1,654,070	1,652,462	1,708,234	1,789,218	5.5%	0.3%
S10 Carbon Cap	1,695,392	1,627,225	1,593,132	1,618,857	1,684,350	-0.7%	0.0%
S1 High Growth	1,696,196	1,733,496	1,755,495	1,838,481	1,964,172	15.8%	0.7%
S4 Ultra Green	1,695,392	1,554,142	1,469,839	1,471,666	1,529,215	-9.8%	-0.5%

Figure ES-10 Forecasts of Annual Energy Use after EE Program Savings



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INTRODUCTION

1.1 RESEARCH OBJECTIVES

The primary objective of this study is to help the Midwest ISO enhance their modeling of future transmission capacity by providing a 20-year load forecast that accounts for demand response (DR) and energy efficiency (EE) for the Midwest ISO region and for the Eastern Interconnection. In the past, the Midwest ISO assumed a reduction in sales and peak of 1% per year to approximate savings from DR and EE programs. In light of all the DR and EE activity taking place across the nation, Midwest ISO initiated this study to develop better and defensible estimates of EE and DR for their forecast.

The primary objective of the study is to develop estimates of DR and EE savings for the Eastern Connection regions according to the taxonomy used to describe resources in the EGEAS model, which the Midwest ISO currently uses for transmission planning studies.

1.2 ANALYSIS FRAMEWORK

To estimate savings from DR and EE programs in the Eastern Interconnection, we used a variety of publicly-available sources of information, as well as the results of the analysis for the Midwest ISO region⁶. A primary source for this study is *A National Assessment of Demand Response Potential*; Staff Report, Federal Energy Regulatory Commission, June 2009 (FERC Study).

The first analysis task was to develop a forecast of system peak demand and annual electricity use for 2010 through 2030 for the ten Eastern Interconnection regions. We started with EIA Form 861 to capture the number of customers and electricity sales for 2008 (the most recent data available) at the state or entity level. The forecast was derived by applying the population growth forecast from the FERC Study. The peak demand forecast was derived by taking the per customer peak estimate by state from the FERC Study and multiplying it by the population. The energy growth forecast for each state was taken from the FERC Study and applied to the 2008 energy estimates.

The second analysis task was to develop projections of DR savings. For this task, the FERC Study provided estimates for the participation rates and load reduction impact associated with DR programs. The utility programs were then grouped so that they could be analyzed in a format consistent with the Midwest ISO's planning model (EGEAS).

The third analysis task was to develop projections of EE savings. The analysis approach applied program participation rates, savings per participant, and program budget per kWh saved that were developed for the Midwest ISO region to the baseline of the Eastern Interconnection.

Finally, we compared the savings estimates to the baseline forecasts. We present the results of the analysis in Chapter 3.

⁶ A detailed account of the analysis for the Midwest ISO region is included in Volume 1 of this report. The Midwest ISO analysis used utility forecast and program information to develop the savings estimates by program type. Collecting utility-provided data on the load forecast and program details were beyond the scope of this project for the Eastern Interconnection analysis.

1.3 REPORT ORGANIZATION

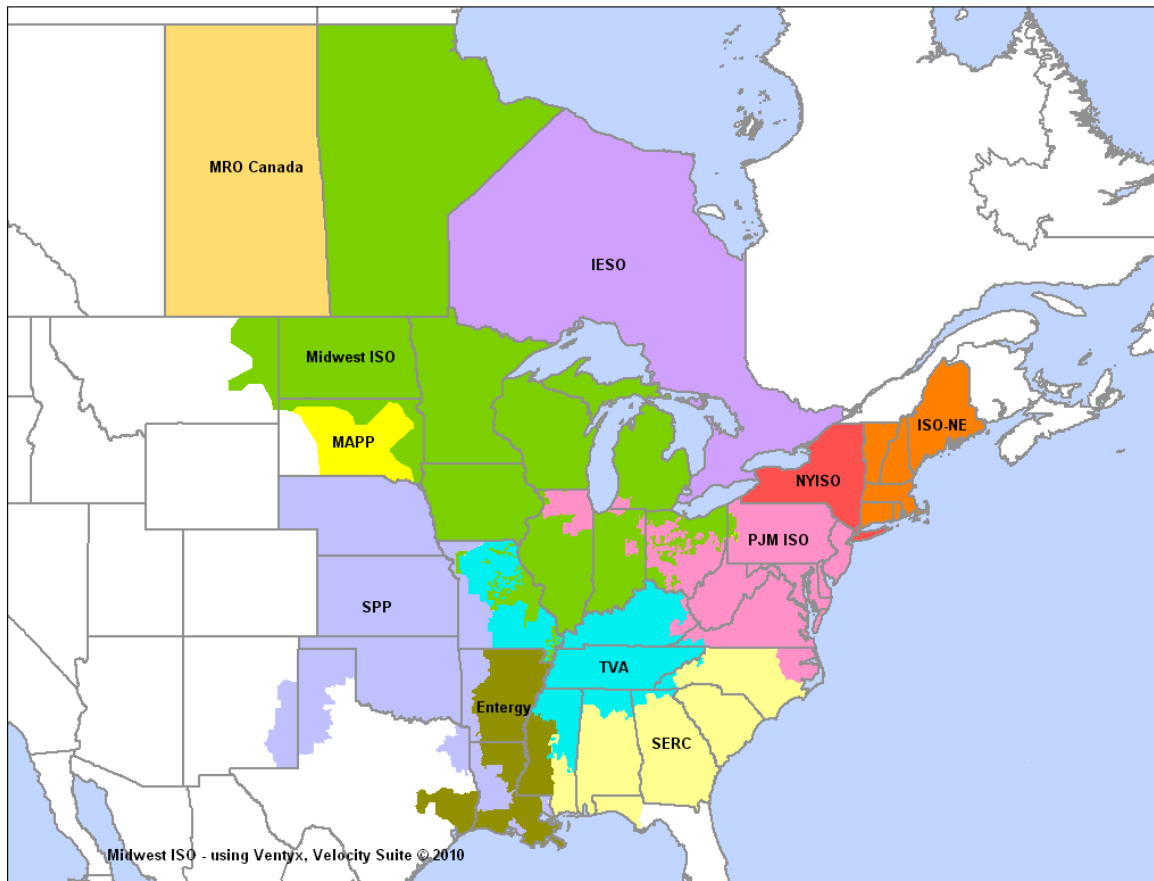
The report is organized into two volumes. The first volume focuses on the Midwest ISO analysis. This second volume focuses only on the Eastern Interconnection regions. It is organized as follows:

Chapter 2 describes the analysis approach for developing the baseline load forecast, estimating demand response and energy efficiency impacts for the regions in the Eastern Interconnection. *Chapter 3* presents the results of the Eastern Interconnection analysis. *Chapter 4* describes the analysis approach and results for the scenario analysis.

ANALYSIS APPROACH

The Eastern Interconnection covers an extensive area: from central Canada east to the coast (excluding Quebec), south to Florida and westward to the Rockies (excluding most of Texas). Figure 2-1 illustrates the geographic area of the Eastern Interconnection.

Figure 2-1 *Map of Eastern Interconnection*



The Eastern Interconnection consists of the following ten planning regions.⁷⁻

1. Entergy
2. IESO
3. ISO- New England
4. MAPP (non-Midwest ISO portion)
5. MRO Canada
6. NYISO

⁷ The Midwest ISO region DR potential estimation is a part of the Eastern Interconnection overall potential. However, the Midwest ISO DR potential discussion is excluded from this volume as it has already been discussed separately in detail in volume 1.

7. PJM
8. SERC
9. SPP
10. TVA

This chapter describes the approach we used to develop DR and EE estimates for the Eastern Interconnection. The first step was to identify the entities included in the Eastern Interconnection. Midwest ISO staff provided a preliminary list of entities which we supplemented with other sources of information. They also provided a mapping of each entity to the appropriate ISO/RTO region. In turn, we mapped each of the entities to the states in which they operate. Some of the entities are generation and transmission (G&T) companies with a number of members. These companies were expanded to include all the retail entities, which primarily included municipal and co-operative utilities. At the conclusion of this process, there are 440 entities in the Eastern Interconnection for which we developed baseline data. Unlike the analysis for the Midwest ISO, which relied extensively on utility data, the EI analysis relied exclusively on secondary data sources as described below.

One important aspect is that we developed each of the data elements at the entity or state level. This retains the differences in characteristics across entities falling within the same planning area, which are quite substantial in some instances. Finally, we aggregated the entity-level and state-level data to develop DR and EE potential estimates for each of the ten planning areas in the Eastern Interconnection.

2.1 BASELINE FORECAST

The baseline forecast includes forecasts of the number of customers, peak demand, annual electricity use and macroeconomic parameters.

2.1.1 Customer Forecast

The first step is to develop an estimate of the number of customers in a recent base year. The primary data source we used to develop these estimates is EIA Form-861.⁸ The most recent year for which data are available is 2008. In addition, we used the database developed for FERC's National Assessment of Demand Response⁹ (the FERC Study). This database is described in Appendix D of the FERC Study report.

- Form 861 reports the number of residential and C&I customers, along with electricity sales for a large number of retail entities serving end-use customers. Form 861 provides data separately for commercial and industrial customers, so we summed them to arrive at C&I population numbers. We used Form 861 data for all entities except those in New York State and the ISO-New England states (Maine, Vermont, New Hampshire, Massachusetts, Connecticut and Rhode Island). For these states, we used the FERC Study database.
- The FERC Study database provides data for each of the 50 states and four rate classes: residential, small C&I, medium C&I and large C&I. We combined the three C&I rate classes to give a weighted average for the C&I sector as a whole in each state.

The next step was to develop customer forecasts for 2009 to 2030. We used the customer growth rates from the FERC Study to develop the forecasts. The database underlying the FERC Study (described in Appendix D of the FERC report) provides data on growth rates by state and the four rate classes. The state-level growth rates were applied to all entities that belonged to a particular state. For entities belonging to states that were covered by the utility survey for the Midwest ISO area, customer population growth rates were based on the survey data.

For the ISO-New England states, New York State under NYISO, and the two Canadian provinces of Ontario and Saskatchewan, we used a slightly different approach. For the ISO-NE states and

⁸Data source available at <http://www.eia.doe.gov/cneaf/electricity/page/eia861.html>

⁹ Include full citation

New York, we obtained customer data for 2008 and forecasts at the state level directly from the FERC study database. For the two Canadian provinces, we used residential population data from Natural Resources Canada's Office of Energy Efficiency Database.¹⁰ However, the remaining estimates for Canada were developed based on best possible approximations from U.S. states.¹¹

2.1.2 Peak Demand Forecast

We developed peak demand estimates by rate class at the state level using the FERC Study. This consists of peak demand for the base year, as well as forecasts through 2030. For the C&I customers, we combined data for small, medium and large C&I customers from the FERC Study.

For the two Canadian provinces, we based our estimates on information for U.S. states with similar characteristics.¹²

2.1.3 Energy Sales Forecast

Similar to the customer forecast, we used EIA Form-861 and the FERC Study to develop the energy sales forecast. Form-861 provides data for the base year. We combined data for commercial and industrial customers to arrive at C&I energy sales. We used the energy sales forecasts from the FERC study and applied these to the baseline sales values.

For the two Canadian provinces, we obtained historical residential, commercial, and industrial energy consumption data from Office of Energy Efficiency Database.¹³ We used historical sales data to develop forecasts for the two provinces.

2.1.4 Macroeconomic Parameters

The assumptions for the discount rate and the inflation rates are the same as for the Midwest ISO area; the discount rate is assumed to be 8% and the inflation rate is assumed to be 3%. Both these rates are held constant over the time period of the study.

2.2 DEMAND RESPONSE ANALYSIS

The DR program analysis requires assumptions about the types of DR programs, as well customer participation, unit load reduction impacts, and program costs for each of the programs. We describe these elements in this section.

2.2.1 Overview of DR Programs

For the Eastern Interconnection we looked at four DR options:

- DHYD- Direct Load Control (DLC) for residential and C&I customers
- DTHR- Interruptible/Curtailable Option for C&I customers only
- DHYD- Dynamic Pricing for both residential and C&I customers
- DTHR- 'Other DR' Option for C&I customers only

These are the same options we considered in Midwest ISO analysis, with the addition of the DTHR "Other DR" option for C&I customers. Based on the FERC Study¹⁴, the 'Other DR' category

¹⁰Please refer to http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/comprehensive_tables/index.cfm?attr=0.

¹¹Please note that the estimates for the Canadian provinces are based on limitations of time and resources available for the present study. Further data refinements will be required to come up with more accurate estimates for the Canadian provinces. The residential customer population size for Ontario was very close to the customer population for the state of Pennsylvania (PA). Based on that similarity, we applied the customer population growth rates for PA to Ontario (ONT) to come up with the forecast numbers. Similarly, the residential customer population size for Saskatchewan (SK) was very close to the customer population for the state of Indiana (IN). So the growth rate for IN was applied to SK to come up with population forecasts for residential customers. The C&I customer population data was not readily available for the Canadian provinces. For ONT, the ratio of C&I to residential customers for PA was applied to come up with C&I customer estimates for the study time period. For SK, a similar ratio for IN was applied to come up with C&I population estimates based on the residential data.

¹²For ONT, we assumed the peak load to be an average of the estimates for the New England states, based on geographical proximity and similar weather characteristics. The New England states include Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. On a similar basis, for SK, we assumed the peak load to be the same as that for Montana based on geographical proximity and likely similar weather characteristics.

¹³Please refer to http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/comprehensive_tables/index.cfm?attr=0

includes programs primarily available to medium and large commercial and industrial customers in the form of capacity bidding, demand bidding, and other aggregator offerings, whether operated by an ISO, RTO, or a utility in an area without an ISO or RTO. This category also includes demand response bid into capacity markets. Some of these programs are primarily price-triggered while others are triggered based on reliability conditions.

2.2.2 Key Modeling Assumptions

The FERC Study provides a comprehensive source of information for the key modeling assumptions for the four program scenarios¹⁵ evaluated in the study. For the analysis of the Eastern Interconnection, we base our estimates on the assumptions for the 'Expanded Business-As-Usual (EBAU)' scenario as described below.

2.2.2.1 Central Air Conditioning (CAC) Saturation

CAC saturations are used to define the potential number of participants for direct load control programs. The FERC Study contains CAC saturation by rate class by state and we used this information to develop saturations for the residential and C&I sectors. We applied the information for each state to all entities belonging to a particular state. For the two Canadian provinces, we used best possible approximations based on data for U.S. states.¹⁶

2.2.2.2 Customer Participation Rates

It is possible for the same customers to participate in more than one DR program. To prevent double counting, we assume an order to the programs. Residential customers have two DR program options and we assume that customers are first offered the choice to participate in DLC programs. Those who do not participate in DLC programs are eligible to participate in Dynamic Pricing programs.

C&I customers have four DR program choices: DLC, Interruptible/Curtailable, Dynamic Pricing, and Other DR programs. For these customers, we assume that they are first offered the choice to participate in DLC programs. Those who do not participate in DLC are eligible for interruptible/curtailable contracts. If they do not sign up for these contracts, they are eligible for participation in dynamic pricing programs. The remaining population is eligible to participate in "Other DR" programs.¹⁷

Regarding the ramp-up for participation in DR programs, the FERC Study assumed that maximum participation levels are reached in five years, over the 2009-2014 time horizon. We followed the same assumption in this study. Therefore for all DR programs, participation levels (in terms of % of the eligible population) reach a maximum in 2014 and remain constant thereafter.

For DLC programs, the eligible customers are those with central air conditioning (CAC). Participation rates in DLC programs for both residential and C&I customers are consistent with EBAU scenario assumptions in the FERC Study. For Interruptible/Curtailable and Other DR programs, we define participation rates as a percentage of eligible load, instead of the number of customers and the assumptions are consistent with the EBAU scenario in the FERC Study.

For dynamic pricing programs, the participation rates reflect a combination of data from the FERC Study and the assumptions related to dynamic pricing potential we developed for the

14 Source: National Assessment of Demand Response Potential; Staff Report, Federal Energy Regulatory Commission, June 2009.

15 For a detailed description of the scenarios, please refer to the FERC report- (National Assessment of Demand Response Potential; Staff Report, Federal Energy Regulatory Commission, June 2009).

The Business-as-Usual scenario, considers the amount of demand response that would take place if existing and currently planned demand response programs continued unchanged over the next ten years. Such programs include interruptible rates and curtailable loads for Medium and Large commercial and industrial customers, as well as direct load control of large electrical appliances and equipment, such as central air conditioning, of Residential and Small commercial and industrial consumers. The Expanded Business-as-Usual scenario is the Business-as-Usual scenario with the following additions: 1) the current mix of demand response programs is expanded to all states, with higher levels of participation ("best practices" participation levels); 2) partial deployment of advanced metering infrastructure; and 3) the availability of dynamic pricing to customers, with a small number of customers choosing dynamic pricing.

16 Similar to the approach used for peak load estimation- for ONT, we assumed the CAC saturation value to be the same as the average for the New England states. For SK, we assumed the CAC saturation to be the same as that for Montana.

17 The participation order or hierarchy for this analysis is similar to what was followed for the Midwest ISO region.

Midwest ISO (see Volume 1). We assume 20% of residential customers and 10% of C&I customers participate in dynamic pricing by 2020.

Residential customers with CAC are eligible to participate with enabling technology such as programmable communicating thermostat (PCT), but only a fraction of the eligible customers accept enabling technology and participate in pricing programs. For the remaining customers with CAC who do not accept enabling technology, a fraction still participates in dynamic pricing. Finally, customers without CAC can also participate in dynamic pricing programs. As a result, we developed three separate participation rates for pricing programs for each sub-group of residential customers:

1. Customers with CAC who accept enabling technology
2. Customers with CAC who do not accept enabling technology
3. Non-CAC customers

As mentioned above for DLC programs, the FERC Study provides ramp rates for participation in dynamic pricing programs.

For C&I customers, we isolate two groups: customers with and without enabling technology. The percentage of customers accepting enabling technology is similar to what has been assumed for the Midwest ISO area.¹⁸

2.2.2.3 Unit Impacts

Unit load reduction impacts are the amount of savings that occur when customers participate in each program. For all the programs, the FERC Study provides estimates for the unit impacts.

- For DLC programs, we define unit load reduction impacts in terms of kW reduction per customer. In addition, there are energy savings associated with the assumption of eight events per season, with an average duration of 4-hours.
- For Interruptible/Curtailable programs, we represent load reduction impact as a percentage of enrolled load.
- For pricing programs, we developed separate load reduction estimates for customers with and without enabling technology, which are applied to the participants with and without enabling technology to arrive at aggregate load reduction impacts.
- For Other DR programs, the load reduction impact is the same approach as was used for the Interruptible/Curtailable programs.

For the two Canadian provinces, load reduction approximations are based on data from U.S. states.¹⁹

2.2.2.4 DR Program Costs

We used the per kW cost estimates from the Midwest ISO area and adjusted those costs relative to the gross domestic product (GDP) per capita by state to estimate costs associated with DR programs for the Eastern Interconnection area. The indexing of the costs to the per capita GDP provided us with a reasonable variation in costs across different states and regions.

2.3 ENERGY EFFICIENCY ANALYSIS

For the EE program analysis, we defined the set of EE programs and developed estimates of customer participation rates, impacts per participant, and EE program costs for each program.

¹⁸ For assessing the pricing potential in the Midwest ISO area, the percentage of residential customers accepting enabling technology was assumed to grow from 40% in 2010 to 75% in 2020 and remain steady thereafter. For C&I customers, the corresponding acceptance rate grew from 20% in 2010 to 50% in 2020.

¹⁹ Similar to the approach followed for CAC saturation and peak load estimation, the per unit impact for ONT is assumed to be the average of the values for the New England states, while for SK we use the same estimate as that for Montana.

2.3.1 Overview of EE Programs

We conducted the EE potential assessment for four program blocks (in the same manner as the analysis for the Midwest ISO regions) for each of the ten planning areas:

- DNDT – Residential Low-Cost Programs
- DNDT - C&I Low-Cost Programs
- DNDT – Residential High-Cost Programs
- DNDT – C&I High-Cost Programs

2.3.2 EE Analysis Approach

Our approach centers on the application of program participation rates, savings per participant, and program budget per kWh saved developed for the Midwest ISO EE savings potential analysis to the Eastern Interconnection. In order to apply the Midwest ISO data elements to the Eastern Interconnection, it is first necessary to establish a mapping of the Eastern Interconnection regions to an appropriate and representative Midwest ISO region (West, Central, and East). Table 2-1 shows the mapping. For each state/province within the Eastern Interconnection, we identified one of the three Midwest ISO regions as the representative region. We based our selection on the following program implementation characteristics of the three Midwest ISO regions:

- **Midwest ISO West:** This region has the most experience in energy-efficiency program implementation and achieving program impacts since energy efficiency programs have been established and in place for a number of years.
- **Midwest ISO Central:** This region is relatively new to energy-efficiency program implementation, but utilities in this region are planning and/or are mandated to aggressively pursue energy efficiency in the future.
- **Midwest ISO East:** Utilities in this region generally do not have significant experience with energy efficiency program implementation and/or are not required to achieve specific energy-efficiency goals.

For example, we mapped states such as Nebraska and Kansas to the Midwest ISO East region because utilities in these states are not currently mandated by state legislation to meet specific energy-efficiency goals and generally do not have significant experience in implementing energy-efficiency programs.

We performed this mapping of the Eastern Interconnection at the state/province-level because many of the ten Eastern Interconnection planning areas (ISO/RTO regions) cover multiple states/provinces. The implication of this mapping is that we will utilize data from the mapped Midwest ISO region to develop the EE savings for the customers in each Eastern Interconnection state/province. For example, we will use the Midwest ISO East region data to develop the EE potential for customers in West Virginia, and we will use the Midwest ISO Central region data for customers located in Maryland.

We also created modified Midwest ISO regions called “Central (Modified)” and “East (Modified)” to capture climate and other regional differences in the southern-most states. Similarly, we created a “West (Modified)” region to capture climate and other regional differences in the New England region.

Table 2-1 Mapping of Eastern Interconnection to Midwest ISO Region

Eastern Interconnection State/Province	Included ISO/RTO Region(s)	Mapped Midwest ISO Region
AL	SERC, TVA	East (Modified)
AR	Entergy, SPP	East
CT	ISO-NE	West (Modified)
DC	PJM	Central
DE	PJM	Central
GA	SERC	East (Modified)
IL	PJM	Central
IN	PJM	Central
KS	SPP	East
KY	PJM, TVA	East
LA	Entergy, SPP	East (Modified)
MA	ISO-NE	West (Modified)
Manitoba, Canada	MRO-Canada	East
MD	PJM	Central
ME	ISO-NE	West (Modified)
MI	PJM	Central
MO	SPP, TVA	Central
MS	Entergy, SERC, TVA	East (Modified)
NC	SERC, TVA	Central
ND	MAPP	East
NE	SPP	East
NH	ISO-NE	West (Modified)
NJ	PJM	Central
NM	SPP	Central (Modified)
NY	NYISO	West (Modified)
OH	PJM	Central
OK	SPP	Central
Ontario, Canada	IESO	West (Modified)
PA	PJM	Central
RI	ISO-NE	West (Modified)
SC	SERC	East (Modified)
SD	MAPP	East
Saskatchewan, Canada	MRO-Canada	East
TN	Entergy, TVA	East
TX	Entergy, SPP	Central (Modified)
VA	PJM	Central
VT	ISO-NE	West (Modified)
WV	PJM	East

To create these proxy regions, we started with all of the characteristics of the Midwest ISO Central, East, and West regions and made an adjustment to the kWh savings per participant parameters. Table 2-2 shows the factors we used to make this adjustment. These adjustment factors were developed by using savings per participant data for the Midwest, Northeast, and South census regions obtained from the EPRI National Potential Study.

Table 2-2 Development of Adjustment Factors for Proxy Regions

Census Region	Electricity Consumption in 2030 (TWh)	% RAP of Load in 2030	RAP in 2030 (TWh)	Number of Customer Accounts	kWh savings per account	Adjustment Factor
Midwest Census Region						
Residential	320	6.80%	22	32,143,265	677	1.00
Commercial	410	7.70%	52	5,126,129	10,056	1.00
Industrial	270	7.40%				
Northeast Census Region [used to adjust “West (Modified)”]						
Residential	190	9.20%	17	24,284,295	720	1.06
Commercial	300	8.70%	33	3,932,625	8,491	0.84
Industrial	90	8.10%				
South Census Region [used to adjust “Central (Modified)” and “East (Modified)”]						
Residential	900	7.00%	63	62,433,858	1,009	1.49
Commercial	900	9.20%	119	10,041,615	11,831	1.18
Industrial	500	7.20%				

2.3.2.1 Key Modeling Assumptions

Once each of the ten planning areas within the Eastern Interconnection were divided into specific states/provinces and mapped to an appropriate Midwest ISO region, the next step is to calculate the energy savings due to EE programs. In order to do this, we need the following data:

1. Number of customers in each year of the forecast: these are part of the baseline forecast described above.
2. Program participation rates: We used the rates from the appropriate Midwest ISO region as mapped to the specific Eastern Interconnection state/province.
3. kWh savings per participant: We used the values from the appropriate Midwest ISO region.

Note that the participation rates and kWh savings per participant vary by program type and block (e.g. Residential Low-Cost, Residential High-Cost, etc.). The number of participants in each program type is computed by multiplying the number of customers by the program participation rates. The energy savings due to EE programs can then be computed by multiplying the number of participants by the kWh savings per participant.

To calculate the demand savings, we multiply the energy savings by the appropriate kW savings per MWh savings ratio from the mapped Midwest ISO region.

To calculate program costs, we multiply the energy savings by the appropriate budget per MWh savings ratio from the mapped Midwest ISO region.

RESULTS FOR EASTERN INTERCONNECTION

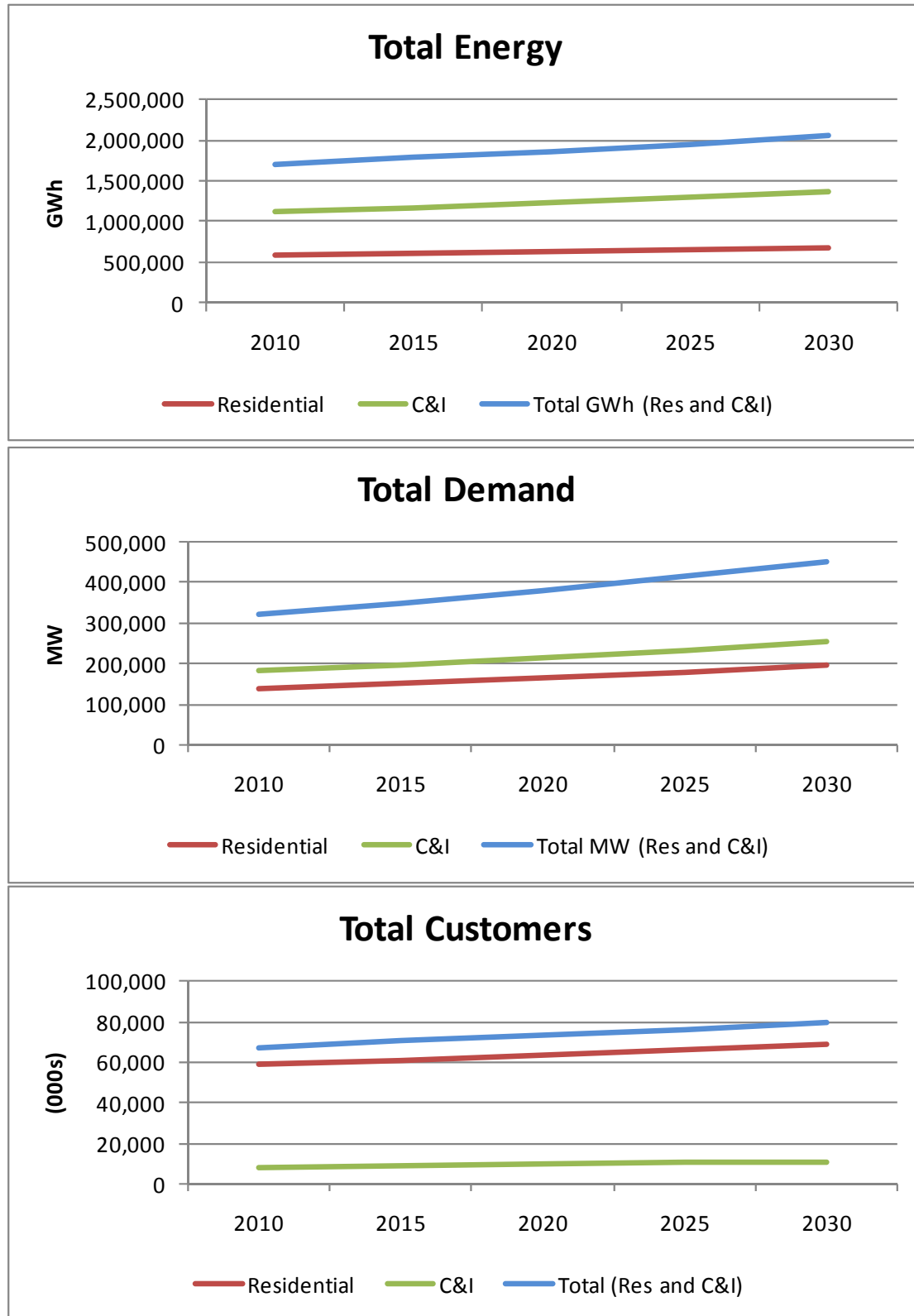
3.1 BASELINE FORECAST FOR EASTERN INTERCONNECTION

The baseline load forecast was developed for each of the ten regions within the Eastern Interconnection as described in Chapter 2. Table 3-1 and Figure 3-1, on the following pages, present the aggregated baseline forecast for the entire Eastern Connection (excluding the Midwest ISO regions). Over the 20-year horizon, electricity sales increase from 1,573 TWh in 2010 to 1,884 TWh in 2030, an increase of 20%. This implies an average annual growth rate of 0.9%. Peak demand increases by almost 40%, from 279 GW in 2010 to 389 GW in 2030. Both sales and peak demand outpace customer growth, which has an average annual growth rate of 0.8%.

The rest of this section show the results for each region in the Eastern Interconnection.

Table 3-1 Total Eastern Interconnection Baseline Forecast

Sales (GWh)	2010	2015	2020	2025	2030	% Increase (2010-30)	Average Annual Growth (%)
Residential	593,966	613,759	635,601	659,495	685,738	15%	0.7%
C&I	1,112,046	1,169,934	1,229,640	1,291,898	1,359,527	22%	1.0%
Total GWh (Res, C&I)	1,706,012	1,783,693	1,865,241	1,951,393	2,045,265	20%	0.9%
Peak Demand (MW)	2010	2015	2020	2025	2030	% Growth (2010-30)	Average Annual Growth (%)
Residential	139,623	152,129	165,721	180,540	196,703	41%	1.7%
C&I	182,071	198,086	215,380	234,284	254,964	40%	1.7%
Total MW (Res, C&I)	321,693	350,215	381,101	414,824	451,667	40%	1.7%
Customers (000)	2010	2015	2020	2025	2030	% Growth (2010-30)	Average Annual Growth (%)
Residential	58,999	61,267	63,624	66,091	68,675	16%	0.8%
C&I	8,521	9,090	9,697	10,349	11,051	30%	1.3%
Total (Res, C&I)	67,520	70,357	73,321	76,440	79,726	18%	0.8%

Figure 3-1 *Total Eastern Interconnection Aggregated Baseline Forecast by Customer Class*

3.1.1.1 Entergy

Table 3-2 and Figure 3-2 show the baseline forecast of energy, demand, and customers for Entergy. Over the 20-year horizon, electricity sales increase from 102.6 TWh in 2010 to 124.7 TWh in 2030, an increase of 22%. This implies an average annual growth rate of 1.0%. Peak demand increases by 44%, from 19.2 GW in 2010 to 27.6 GW in 2030. Customer growth increases by 21%, an average annual growth rate of 1.0%. Overall, the Entergy region grows slightly faster than the overall average for the Eastern Interconnection.

Table 3-2 Baseline Forecast for Entergy

Sales (GWh)	2010	2015	2020	2025	2030	% Increase (2010-30)	Average Annual Growth (%)
Residential	33,588	34,980	36,435	37,959	39,553	18%	0.8%
C&I	68,988	72,707	76,638	80,793	85,186	23%	1.1%
Total GWh (Res, C&I)	102,576	107,687	113,073	118,752	124,739	22%	1.0%
Peak Demand (MW)	2010	2015	2020	2025	2030	% Growth (2010-30)	Average Annual Growth (%)
Residential	8,317	9,107	9,971	10,917	11,953	44%	1.8%
C&I	10,864	11,902	13,040	14,287	15,653	44%	1.8%
Total MW (Res, C&I)	19,181	21,009	23,011	25,204	27,606	44%	1.8%
Customers (000)	2010	2015	2020	2025	2030	% Growth (2010-30)	Average Annual Growth (%)
Residential	2,342,650	2,441,947	2,547,853	2,660,878	2,781,574	19%	0.9%
C&I	398,337	428,816	461,672	497,093	535,283	34%	1.5%
Total (Res, C&I)	2,740,987	2,870,763	3,009,525	3,157,972	3,316,857	21%	1.0%

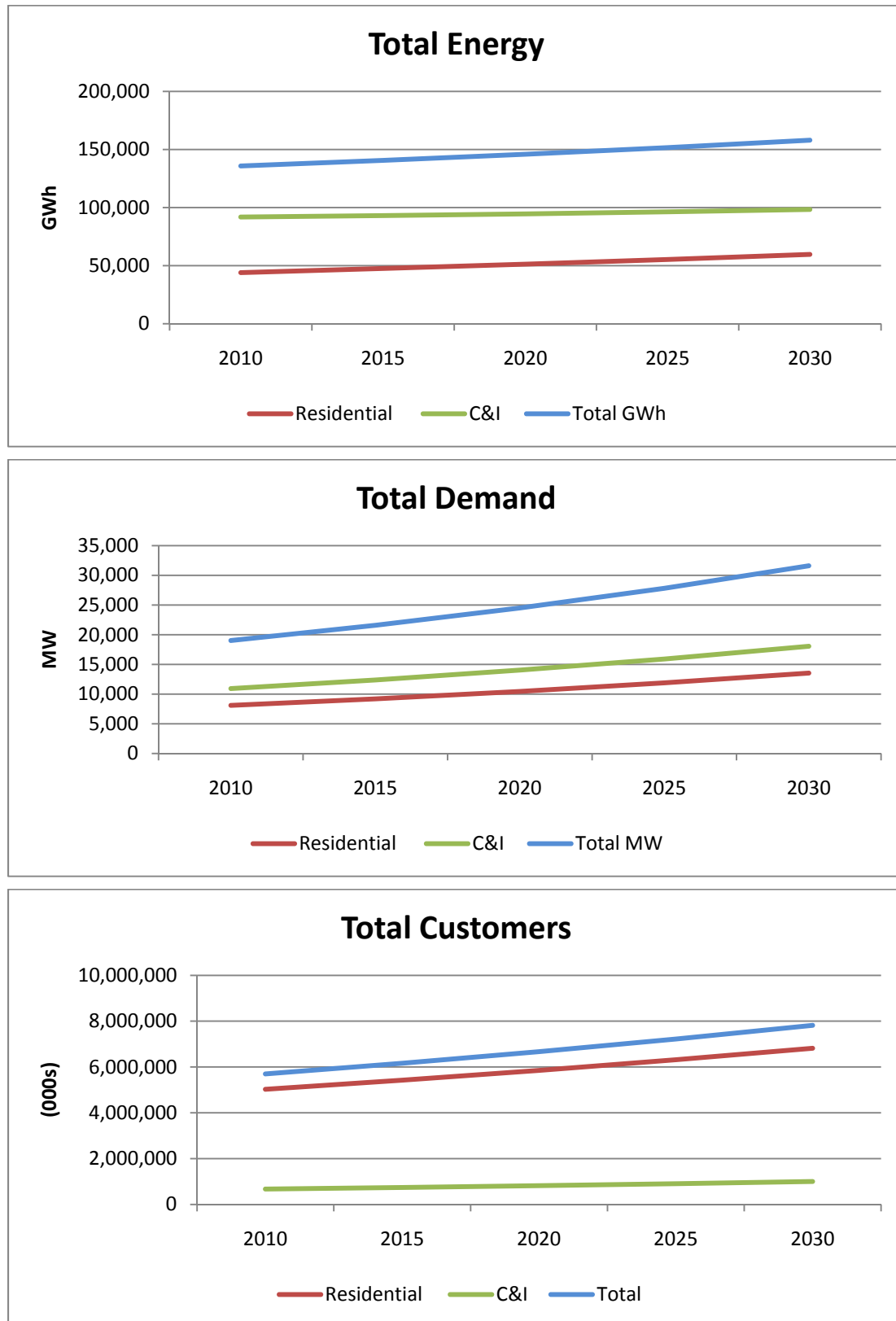
Figure 3-2 Baseline Forecast by Customer Class for Entergy

3.1.1.2 IESO

Table 3-3 and Figure 3-3 show the baseline forecast of energy, demand, and customers for IESO. Over the 20-year horizon, electricity sales increase from 135.8 TWh in 2010 to 158 TWh in 2030, an increase of 16%. This implies an average annual growth rate of 0.8%. Peak demand increases by 66%, from 19 GW in 2010 to 32 GW in 2030. Customer growth increases by 37%, an average annual growth rate of 1.6%. Overall, the IESO region grows faster than the overall average for the Eastern Interconnection.

Table 3-3 Baseline Forecast for IESO

Sales (GWh)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	44,022	47,505	51,263	55,319	59,695	36%	1.5%
C&I	91,798	93,065	94,568	96,313	98,307	7%	0.3%
Total GWh	135,821	140,570	145,831	151,631	158,002	16%	0.8%
Peak Demand (MW)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	8,096	9,201	10,461	11,897	13,537	67%	2.6%
C&I	10,923	12,381	14,037	15,918	18,056	65%	2.5%
Total MW	19,019	21,582	24,497	27,815	31,592	66%	2.5%
Customers	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	5,026,736	5,424,403	5,853,529	6,316,604	6,816,313	36%	1.5%
C&I	670,137	740,595	818,461	904,514	999,614	49%	2.0%
Total	5,696,873	6,164,998	6,671,990	7,221,118	7,815,927	37%	1.6%

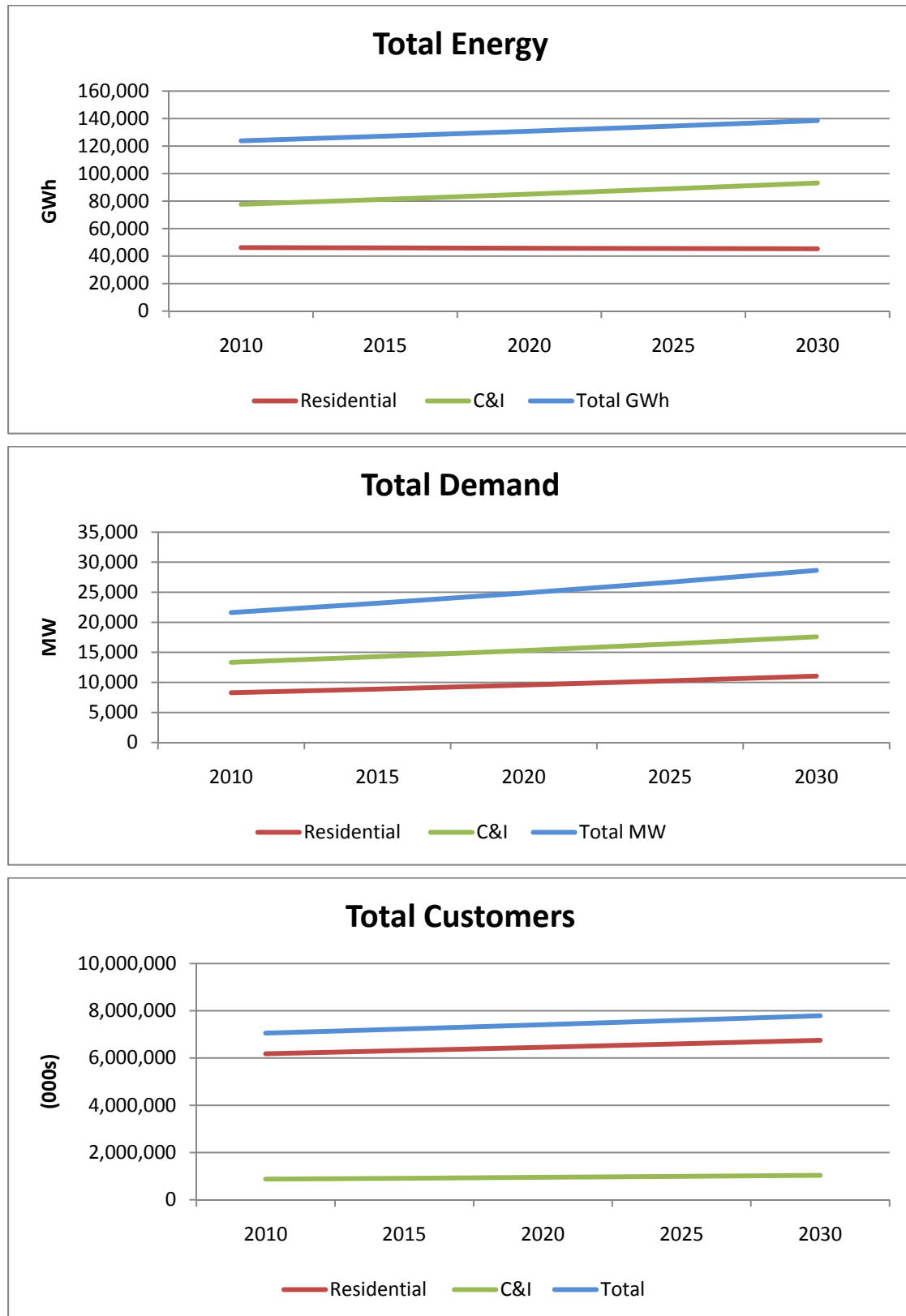
Figure 3-3 Baseline Forecast by Customer Class for IESO

3.1.1.3 ISO-NE

Table 3-4 and Figure 3-4 show the baseline forecast of energy, demand, and customers for ISO-NE. Over the 20-year horizon, electricity sales increase from 123.8 TWh in 2010 to 138.5 TWh in 2030, an increase of 12%. This implies an average annual growth rate of 0.6%. Peak demand increases by 32%, from 21.6 GW in 2010 to 28.6 GW in 2030. Customer growth increases by 10%, an average annual growth rate of 0.5%. Overall, the ISO-NE region grows slower than the overall average for the Eastern Interconnection.

Table 3-4 Baseline Forecast for ISO-NE

Sales (GWh)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	46,191	45,956	45,736	45,530	45,341	-2%	-0.1%
C&I	77,636	81,244	85,021	88,976	93,116	20%	0.9%
Total GWh	123,827	127,200	130,757	134,506	138,457	12%	0.6%
Peak Demand (MW)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	8,277	8,891	9,555	10,274	11,051	34%	1.4%
C&I	13,334	14,280	15,298	16,395	17,577	32%	1.4%
Total MW	21,611	23,171	24,853	26,669	28,628	32%	1.4%
Customers	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	6,179,306	6,316,277	6,456,782	6,600,935	6,748,851	9%	0.4%
C&I	874,282	912,458	952,398	994,189	1,037,926	19%	0.9%
Total	7,053,589	7,228,735	7,409,180	7,595,124	7,786,778	10%	0.5%

Figure 3-4 Baseline Forecast by Customer Class for ISO-NE

3.1.1.4 MAPP

Table 3-5 and Figure 3-5 show the baseline forecast of energy, demand, and customers for MAPP. Over the 20-year horizon, electricity sales increase from 9,783 MWh in 2010 to 13,307 MWh in 2030, an increase of 36%. This implies an average annual growth rate of 1.5%. Peak demand increases by 26%, from 3,601 MW in 2010 to 4,557 MW in 2030. Customer growth increases by 22%, an average annual growth rate of 1.0%. Overall, the MAPP region grows faster than the overall average for the Eastern Interconnection for sales and customers, but the peak demand is slower.

Table 3-5 Baseline Forecast for MAPP

Sales (GWh)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	4,375	4,767	5,158	5,554	5,937	36%	1.5%
C&I	5,409	5,939	6,387	6,861	7,369	36%	1.5%
Total GWh	9,783	10,706	11,545	12,415	13,307	36%	1.5%
Peak Demand (MW)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	851	909	967	1,024	1,082	27%	1.2%
C&I	2,760	2,975	3,142	3,302	3,476	26%	1.2%
Total MW	3,610	3,884	4,109	4,326	4,557	26%	1.2%
Customers	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	407,121	427,849	448,984	469,220	489,103	20%	0.9%
C&I	104,927	113,516	121,501	129,706	138,097	32%	1.4%
Total	512,048	541,364	570,485	598,925	627,199	22%	1.0%

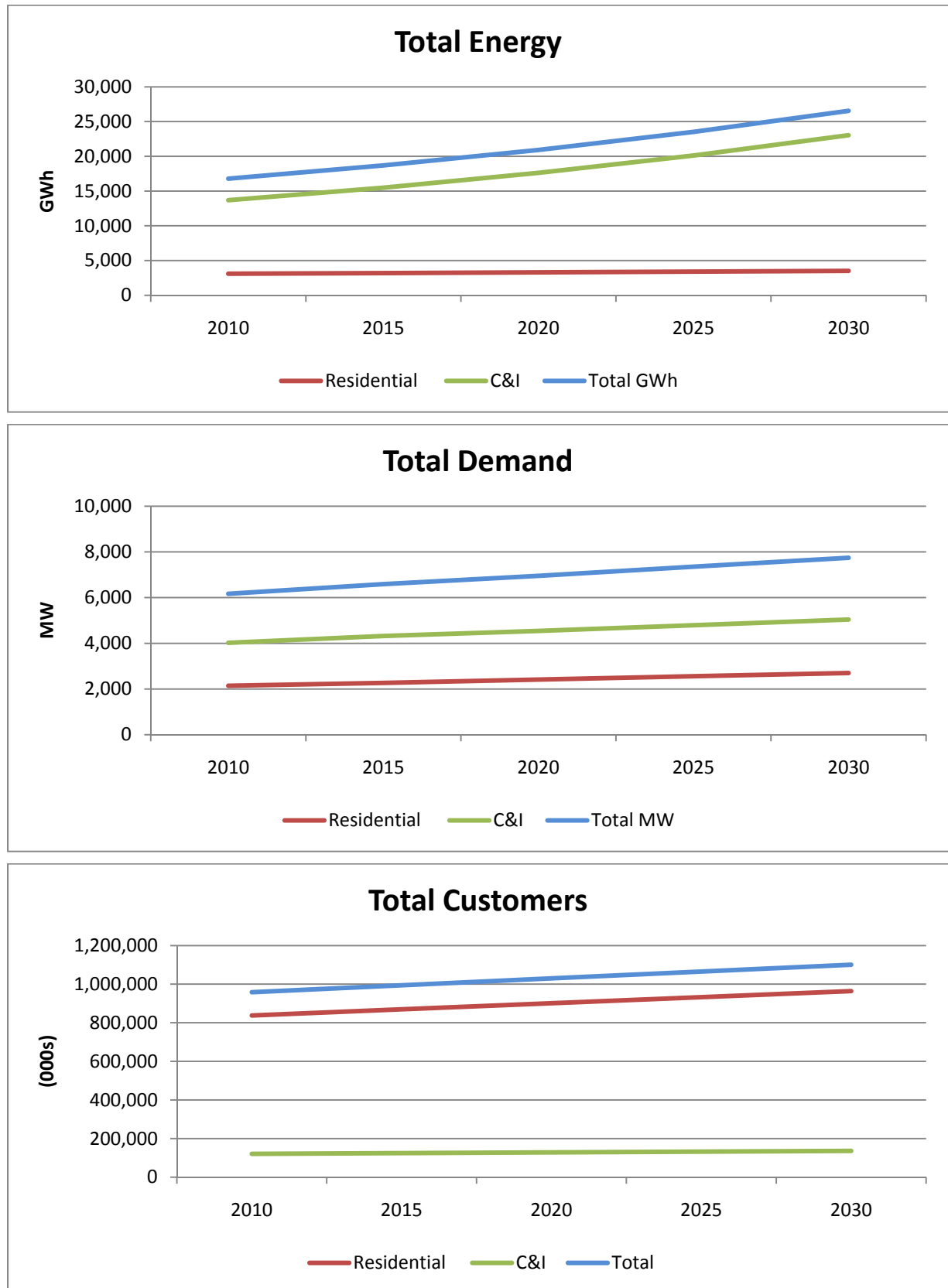
Figure 3-5 **Baseline Forecast by Customer Class for MAPP**

3.1.1.5 MRO-Canada

Table 3-6 and Figure 3-6 show the baseline forecast of energy, demand, and customers for MRO-Canada. Over the 20-year horizon, electricity sales increase from 16,781 MWh in 2010 to 26,549 MWh in 2030, an increase of 58%. This implies an average annual growth rate of 2.3%. Peak demand increases by 26%, from 6,168 MW in 2010 to 7,743 MW in 2030. Customer growth increases by 15%, an average annual growth rate of 0.7%. Overall, the MRO-Canada region grows slower than the overall average for the Eastern Interconnection, except in terms of sales.

Table 3-6 Baseline Forecast for MRO-Canada

Sales (GWh)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	3,103	3,200	3,301	3,405	3,512	13%	0.6%
C&I	13,678	15,491	17,615	20,108	23,036	68%	2.6%
Total GWh	16,781	18,691	20,916	23,513	26,549	58%	2.3%
Peak Demand (MW)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	2,145	2,269	2,412	2,558	2,700	26%	1.2%
C&I	4,023	4,322	4,541	4,793	5,043	25%	1.1%
Total MW	6,168	6,591	6,953	7,351	7,743	26%	1.1%
Customers	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	837,505	869,630	901,427	932,900	964,109	15%	0.7%
C&I	120,830	124,611	128,443	132,387	136,343	13%	0.6%
Total	958,335	994,241	1,029,871	1,065,287	1,100,452	15%	0.7%

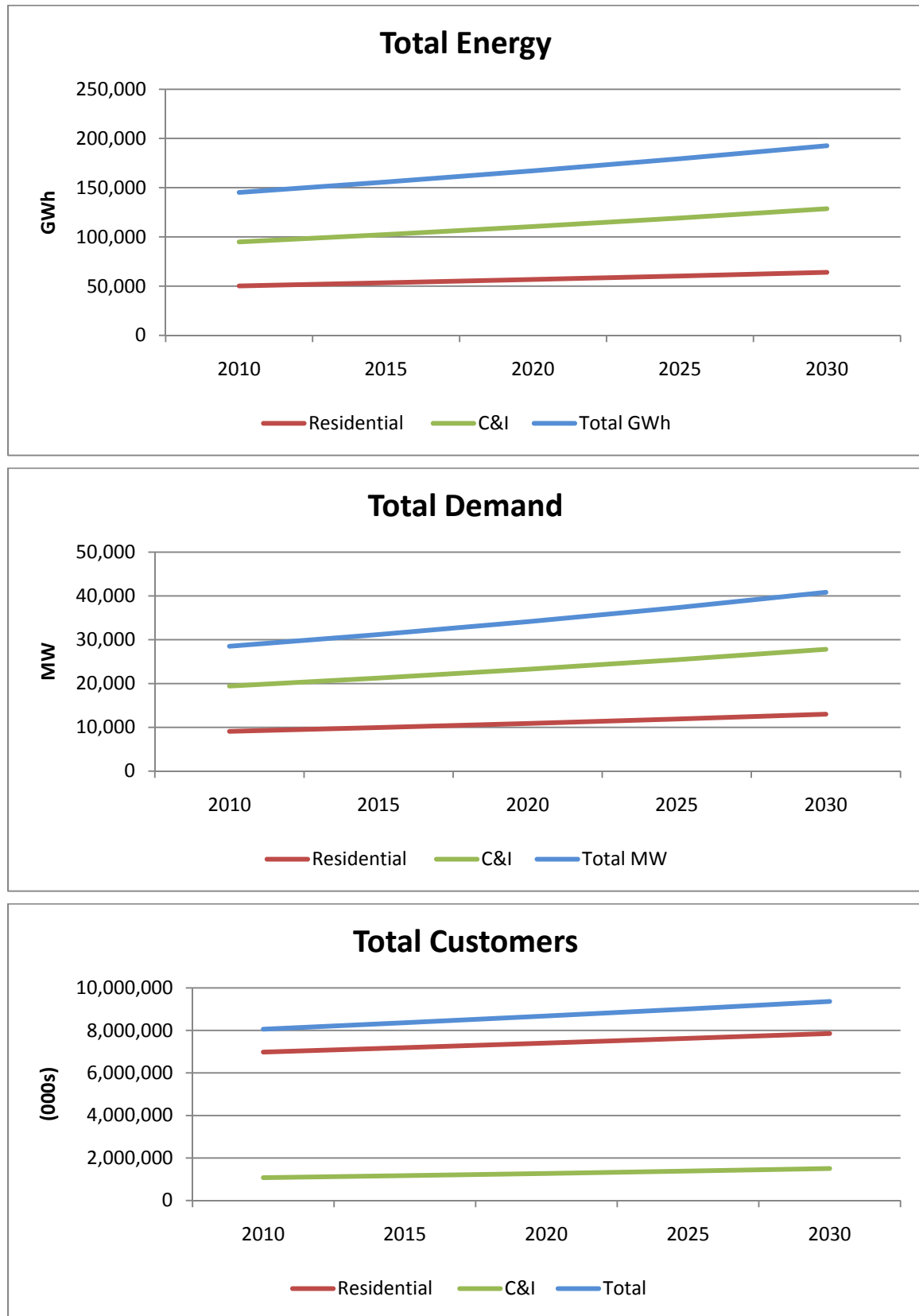
Figure 3-6 **Baseline Forecast by Customer Class for MRO-Canada**

3.1.1.6 NYISO

Table 3-7 and Figure 3-7 show the baseline forecast of energy, demand, and customers for NYISO. Over the 20-year horizon, electricity sales increase from 145 GWh in 2010 to 193 GWh in 2030, an increase of 33%. This implies an average annual growth rate of 1.4%. Peak demand increases by 43%, from 28.5 GW in 2010 to 40.8 GW in 2030. Customer growth increases by 16%, an average annual growth rate of 0.8%. Overall, the NYISO region grows faster than the overall average for the Eastern Interconnection.

Table 3-7 Baseline Forecast for NYISO

Sales (GWh)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	50,239	53,383	56,723	60,273	64,044	27%	1.2%
C&I	94,938	102,419	110,490	119,197	128,589	35%	1.5%
Total GWh	145,177	155,802	167,213	179,469	192,634	33%	1.4%
Peak Demand (MW)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	9,087	9,940	10,873	11,893	13,009	43%	1.8%
C&I	19,430	21,253	23,247	25,429	27,815	43%	1.8%
Total MW	28,517	31,193	34,120	37,322	40,824	43%	1.8%
Customers	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	6,978,829	7,187,448	7,402,303	7,623,581	7,851,474	13%	0.6%
C&I	1,076,575	1,171,248	1,274,247	1,386,304	1,508,215	40%	1.7%
Total	8,055,404	8,358,696	8,676,551	9,009,885	9,359,689	16%	0.8%

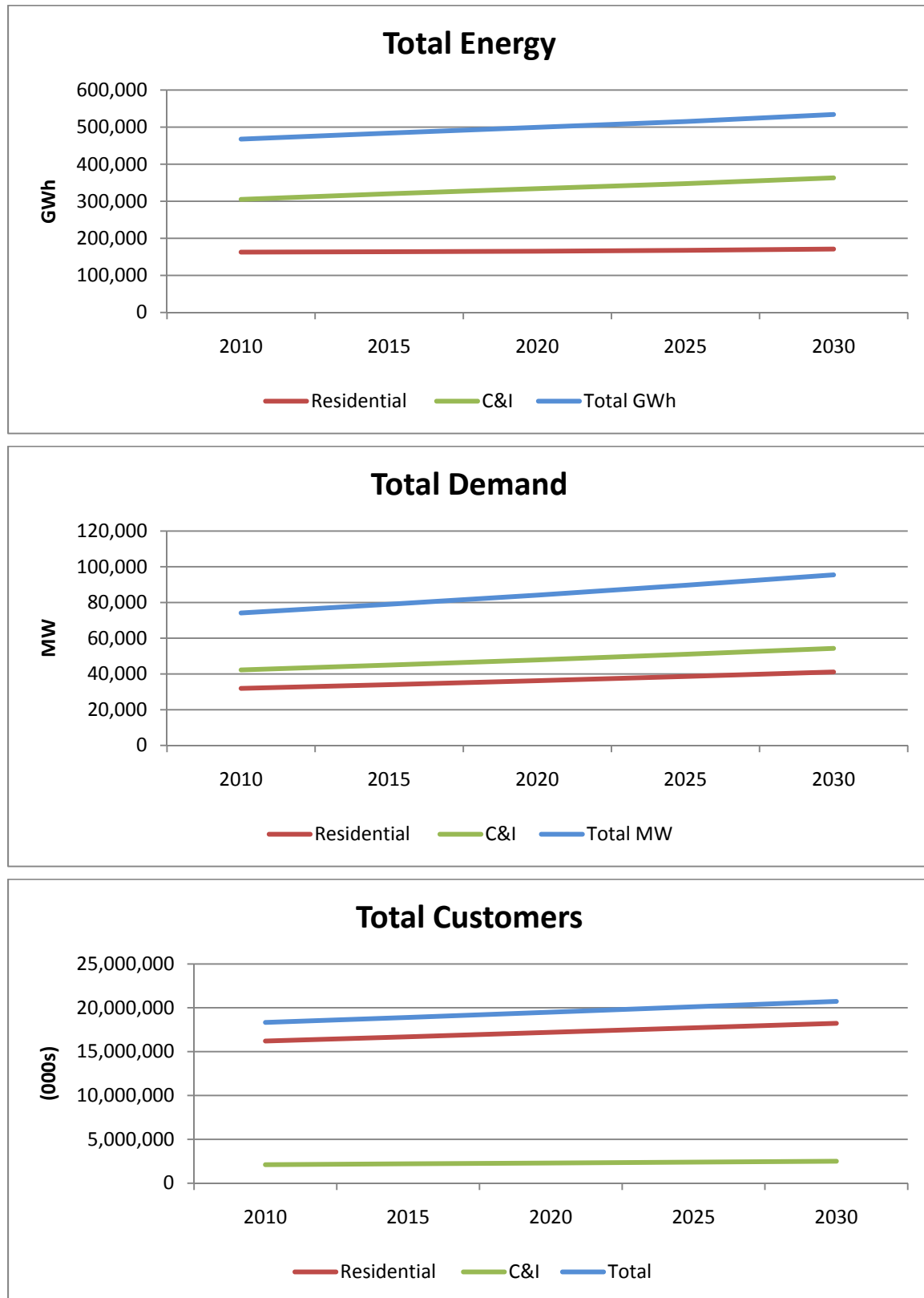
Figure 3-7 Baseline Forecast by Customer Class for NYISO

3.1.1.7 PJM

Table 3-8 and Figure 3-8 show the baseline forecast of energy, demand, and customers for PJM. Over the 20-year horizon, electricity sales increase from 468 GWh in 2010 to 534 GWh in 2030, an increase of 14%. This implies an average annual growth rate of 0.7%. Peak demand increases by 29%, from 74.1 GW in 2010 to 95.4 GW in 2030. Customer growth increases by 13%, an average annual growth rate of 0.6%. Overall, the PJM region grows slower than the overall average for the Eastern Interconnection.

Table 3-8 Baseline Forecast for PJM

Sales (GWh)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	162,694	163,573	165,059	167,426	170,908	5%	0.2%
C&I	304,901	320,030	334,127	347,603	363,013	19%	0.9%
Total GWh	467,594	483,603	499,186	515,029	533,921	14%	0.7%
Peak Demand (MW)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	31,899	34,013	36,250	38,607	41,085	29%	1.3%
C&I	42,245	44,992	47,896	51,010	54,357	29%	1.3%
Total MW	74,144	79,005	84,146	89,617	95,442	29%	1.3%
Customers	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	16,208,347	16,698,454	17,200,120	17,711,619	18,232,382	12%	0.6%
C&I	2,117,123	2,207,620	2,300,981	2,399,193	2,502,824	18%	0.8%
Total	18,325,470	18,906,074	19,501,100	20,110,812	20,735,206	13%	0.6%

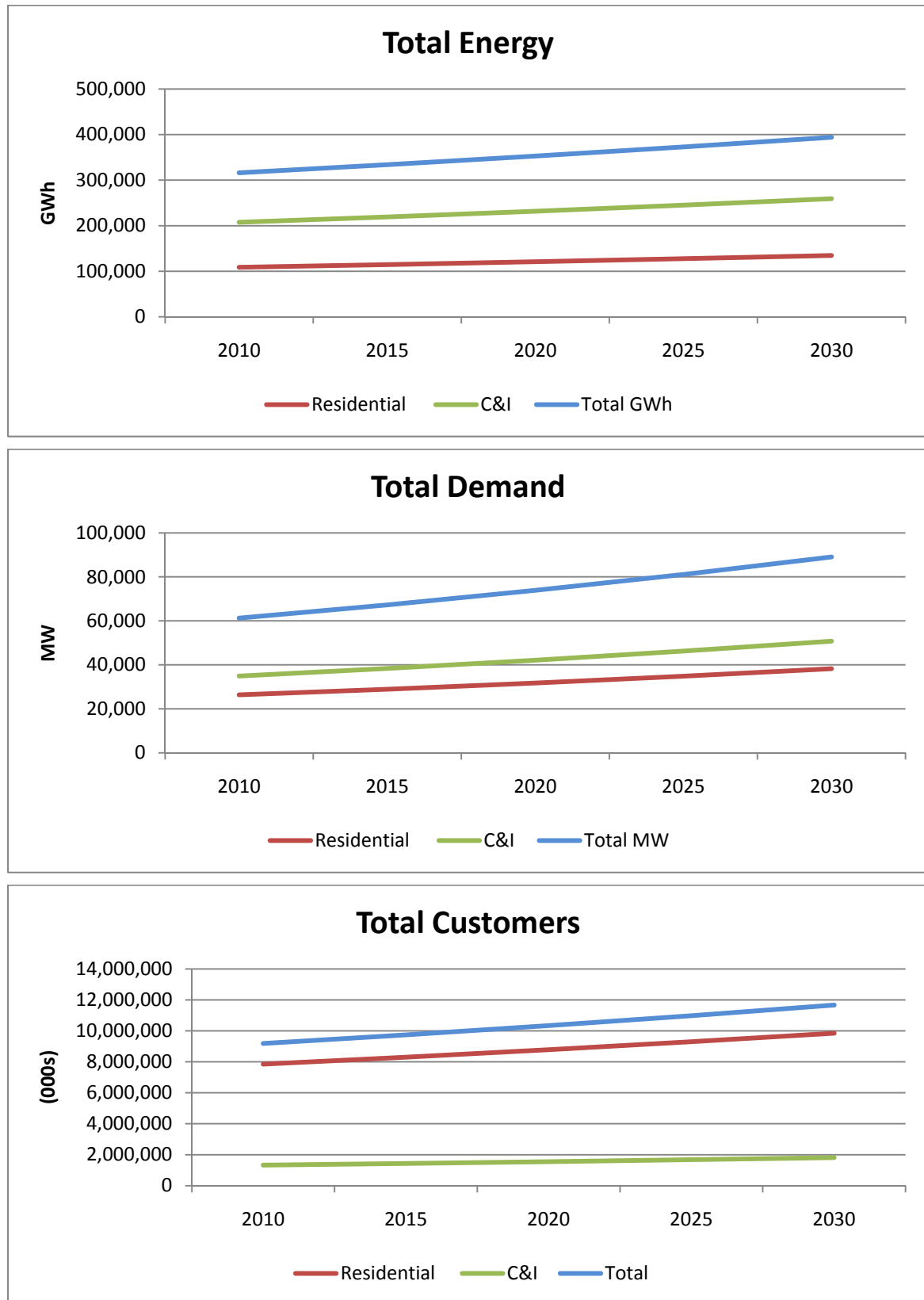
Figure 3-8 **Baseline Forecast by Customer Class for PJM**

3.1.1.8 SERC

Table 3-9 and Figure 3-9 show the baseline forecast of energy, demand, and customers for SERC. Over the 20-year horizon, electricity sales increase from 316 GWh in 2010 to 394 GWh in 2030, an increase of 25%. This implies an average annual growth rate of 1.1%. Peak demand increases by 45%, from 61.3 GW in 2010 to 89 GW in 2030. Customer growth increases by 27%, an average annual growth rate of 1.2%. Overall, the SERC region grows slightly faster than the overall average for the Eastern Interconnection.

Table 3-9 Baseline Forecast for SERC

Sales (GWh)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	108,771	114,691	120,953	127,577	134,584	24%	1.1%
C&I	207,409	219,249	231,820	245,170	259,350	25%	1.1%
Total GWh	316,180	333,940	352,773	372,747	393,934	25%	1.1%
Peak Demand (MW)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	26,358	28,932	31,758	34,859	38,264	45%	1.9%
C&I	34,917	38,345	42,109	46,243	50,783	45%	1.9%
Total MW	61,276	67,277	73,867	81,102	89,047	45%	1.9%
Customers	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	7,848,830	8,299,929	8,781,949	9,297,164	9,848,019	25%	1.1%
C&I	1,331,801	1,438,668	1,554,228	1,679,194	1,814,340	36%	1.5%
Total	9,180,631	9,738,597	10,336,177	10,976,357	11,662,359	27%	1.2%

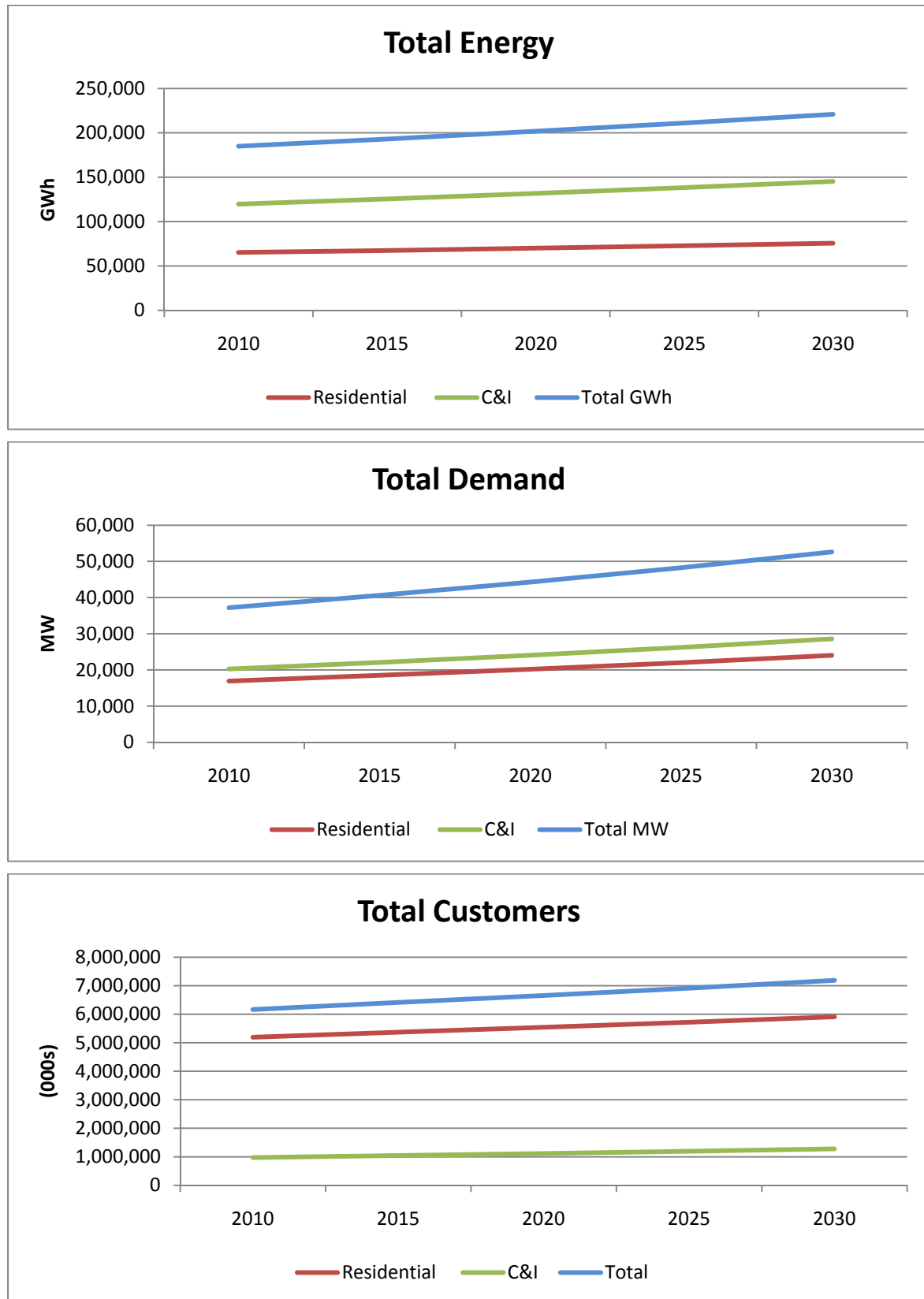
Figure 3-9 Baseline Forecast by Customer Class for SERC

3.1.1.9 SPP

Table 3-10 and Figure 3-10 show the baseline forecast of energy, demand, and customers for SPP. Over the 20-year horizon, electricity sales increase from 185 GWh in 2010 to 221 GWh in 2030, an increase of 19%. This implies an average annual growth rate of 0.9%. Peak demand increases by 41%, from 37.2 GW in 2010 to 52.6 GW in 2030. Customer growth increases by 17%, an average annual growth rate of 0.8%. Overall, the SPP region grows at the same rate as the overall average for the Eastern Interconnection.

Table 3-10 Baseline Forecast for SPP

Sales (GWh)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	65,215	67,464	70,066	72,782	75,621	16%	0.7%
C&I	119,643	125,562	131,789	138,340	145,233	21%	1.0%
Total GWh	184,858	193,026	201,855	211,122	220,854	19%	0.9%
Peak Demand (MW)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	16,929	18,515	20,196	22,026	24,022	42%	1.7%
C&I	20,275	22,100	24,086	26,241	28,597	41%	1.7%
Total MW	37,204	40,615	44,282	48,267	52,620	41%	1.7%
Customers	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	5,190,626	5,367,701	5,540,223	5,720,271	5,909,293	14%	0.6%
C&I	975,152	1,043,429	1,116,382	1,194,167	1,277,845	31%	1.4%
Total	6,165,778	6,411,130	6,656,605	6,914,439	7,187,138	17%	0.8%

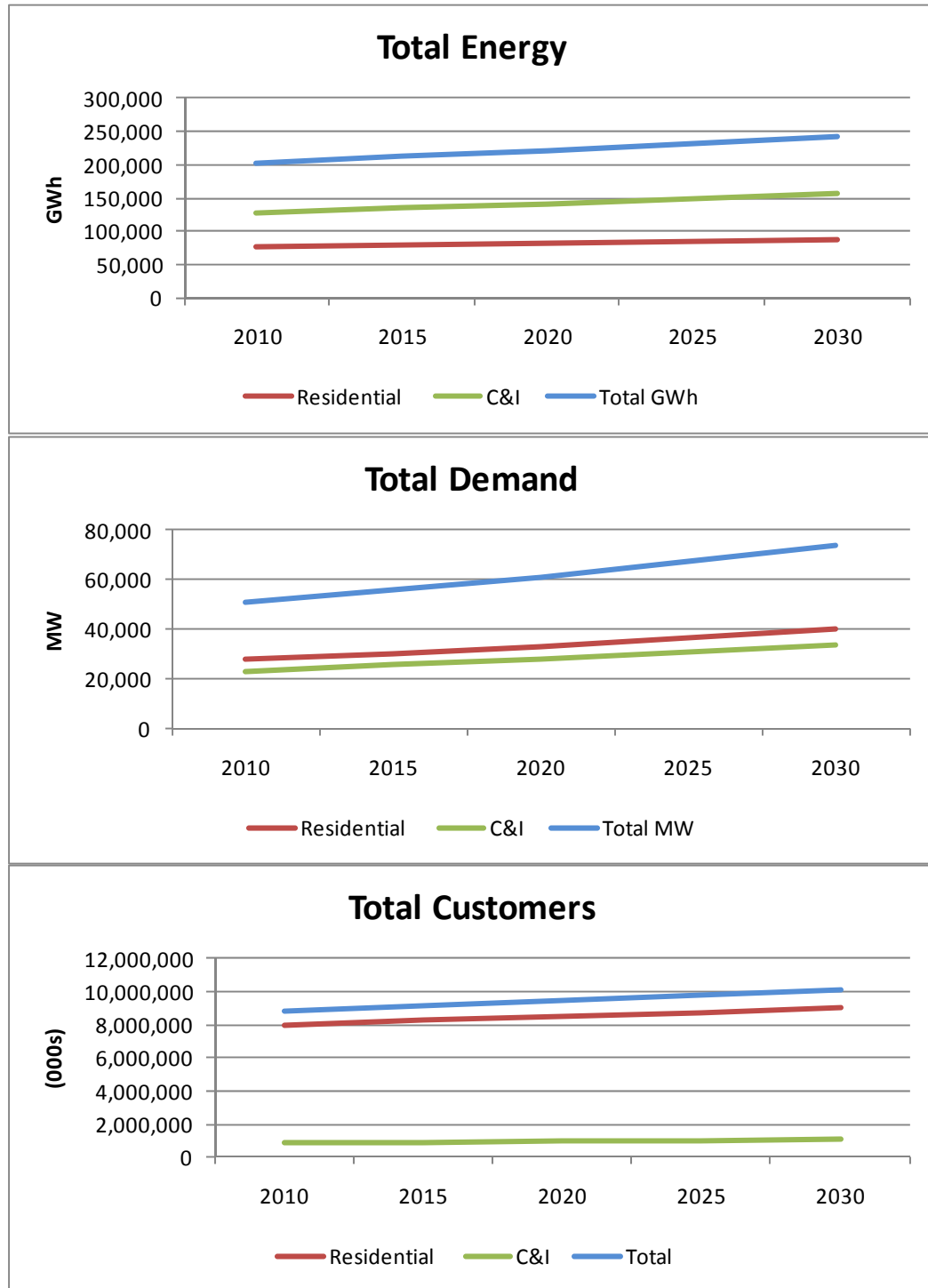
Figure 3-10 Baseline Forecast by Customer Class for SPP

3.1.1.10 TVA

Table 3-11 and Figure 3-11 show the baseline forecast of energy, demand, and customers for TVA. Over the 20-year horizon, electricity sales increase from 203 GWh in 2010 to 243 GWh in 2030, an increase of 19%. This implies an average annual growth rate of 0.9%. Peak demand increases by 44%, from 50,964 MW in 2010 to 73,608 MW in 2030. Customer growth increases by 15%, an average annual growth rate of 0.7%. Overall, the TVA region growth is about average for the Eastern Interconnection.

Table 3-11 Baseline Forecast for TVA

Sales (GWh)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	75,767	78,240	80,906	83,670	86,541	14%	0.7%
C&I	127,646	134,228	141,186	148,538	156,329	22%	1.0%
Total GWh	203,413	212,468	222,092	232,209	242,870	19%	0.9%
Peak Demand (MW)	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	27,664	30,353	33,278	36,485	40,000	45%	1.8%
C&I	23,300	25,536	27,985	30,666	33,608	44%	1.8%
Total MW	50,964	55,888	61,263	67,151	73,608	44%	1.8%
Customers	2010	2015	2020	2025	2030	% Growth (2010-2030)	Average Annual Growth (%)
Residential	7,978,915	8,233,282	8,490,872	8,757,416	9,033,722	13%	0.6%
C&I	852,276	908,627	968,652	1,032,537	1,100,760	29%	1.3%
Total	8,831,191	9,141,909	9,459,524	9,789,953	10,134,482	15%	0.7%

Figure 3-11 Baseline Forecast by Customer Class for TVA

3.2 DEMAND RESPONSE FOR EASTERN INTERCONNECTION

This section presents the results of the demand response analysis for the Eastern Interconnection. These results are exclusive of the demand response potential in the Midwest ISO region, which are discussed in Volume 1.

3.2.1 Summary of Demand Response Results for Eastern Interconnection

Table 3-12 shows the peak-demand savings from demand response programs within the Eastern Interconnection. Savings from demand response are projected to be over 48,500 MW (11% of baseline peak demand) by 2030. In absolute terms, the PJM planning area accounts for the largest amount of savings in 2030, followed by SERC. In terms of percentage of baseline peak demand, ISO-NE and NYISO are estimated to each save almost 14% due to demand response programs.

Table 3-12 Demand Response Savings Potential

RTO/ISO	Demand Savings (MW)					Percentage of Baseline				
	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
Entergy	302	1,292	1,696	1,814	1,941	1.6%	6.2%	7.4%	7.2%	7.0%
IESO	372	1,716	2,078	2,338	2,631	2.0%	7.9%	8.5%	8.4%	8.3%
ISO-NE	2,332	3,207	3,541	3,753	3,979	10.8%	13.8%	14.2%	14.1%	13.9%
MAPP	249	397	452	475	500	6.9%	10.2%	11.0%	11.0%	11.0%
MRO-Canada	78	412	516	541	565	1.3%	6.3%	7.4%	7.4%	7.3%
NYISO	3,196	4,253	4,851	5,238	5,659	11.2%	13.6%	14.2%	14.0%	13.9%
PJM	4,972	8,868	10,136	10,677	11,252	6.7%	11.2%	12.0%	11.9%	11.8%
SERC	3,566	7,242	8,754	9,482	10,275	5.8%	10.8%	11.9%	11.7%	11.5%
SPP	1,331	3,653	4,489	4,785	5,106	3.6%	9.0%	10.1%	9.9%	9.7%
TVA	2,185	4,475	5,884	6,255	6,656	4.3%	8.0%	9.6%	9.3%	9.0%
Total DR	18,584	35,517	42,399	45,357	48,564	5.8%	10.1%	11.1%	10.9%	10.8%

Table ES-13 and Figure 3-12 present the demand-response potential by program type and customer class for the Eastern Interconnection. The C&I class accounts for the largest savings, starting at 15.7 GW in 2010 and increasing to over 32.7 GW in 2030. Within the C&I class, the largest programs are Curtailable/Interruptible and Other. Within the residential sector, direct load control (DLC) programs account for more than half the savings throughout the forecast period.

Table 3-13 Demand Response Potential by Program (MW)

Program	2010	2015	2020	2025	2030
C&I Curtailable/Interruptible	6,315	11,435	12,459	13,579	14,806
C&I DHYD-DLC	74	395	422	450	481
C&I DHYD-Pricing	67	377	1,391	1,487	1,589
C&I DHYD-Other	9,234	12,956	13,425	14,575	15,830
Total C&I	15,689	25,164	27,698	30,091	32,706
Residential DHYD-DLC	2,447	8,311	8,626	8,954	9,298
Residential DHYD-Pricing	448	2,041	6,075	6,312	6,560
Total Residential	2,895	10,353	14,701	15,266	15,858
Total DR EI	18,584	35,517	42,399	45,357	48,564

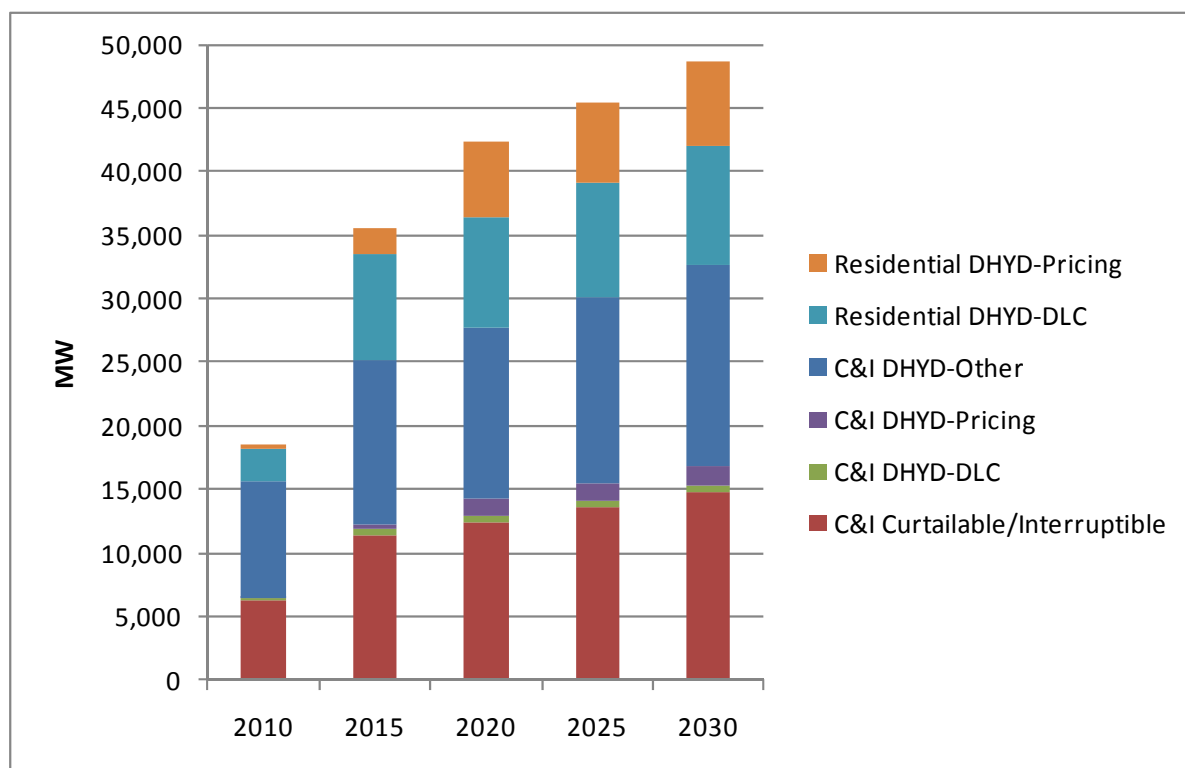
Figure 3-12 Demand Response Potential by Program (MW)

Table 3-14 shows the estimate of the budget, in nominal dollars, required to implement the demand response programs and achieve the incremental savings. During the 2010-2030 timeframe, the annual program budget requirements ramp up during the first half of the period and then level off during the latter portion. The ramping up corresponds to the expected increase in demand response program implementation and activities during the next several years. The demand response program spending will start to decline as more customers participate and the market for participation in these programs approaches saturation limits.

Table 3-14 Demand Response Program Budgets (\$ millions)

Program	2010	2015	2020	2025	2030
C&I Curtailable/Interruptible	\$540	\$963	\$1,179	\$1,484	\$1,868
C&I DHYD-DLC	\$5	\$33	\$41	\$51	\$63
C&I DHYD-Pricing	\$4	\$27	\$112	\$139	\$172
C&I DHYD-Other	\$379	\$576	\$691	\$869	\$1,092
Total C&I	\$929	\$1,600	\$2,024	\$2,543	\$3,197
Residential DHYD-DLC	\$388	\$1,417	\$1,705	\$2,053	\$2,472
Residential DHYD-Pricing	\$33	\$184	\$593	\$714	\$861
Total RES	\$421	\$1,601	\$2,298	\$2,767	\$3,333
Total Budget EI	\$1,350	\$3,201	\$4,322	\$5,310	\$6,530

Table 3-15 shows the average cost per kW saved for the demand response programs. The values are increasing over time since the early adopters are captured in the early portion of the forecast horizon. In addition, most utilities will have their AMI system installed by 2015, allowing utilities to more easily offer demand response programs to their customers.

Table 3-15 Demand Response – Average Cost per kW Saved

Program	2010	2015	2020	2025	2030
C&I Curtailable/Interruptible	\$114	\$103	\$115	\$133	\$154
C&I DHYD-DLC	\$78	\$90	\$105	\$121	\$141
C&I DHYD-Pricing	\$66	\$78	\$90	\$105	\$121
C&I DHYD-Other	\$41	\$46	\$53	\$61	\$71
Weighted Average C&I	\$66	\$70	\$81	\$94	\$109
Residential DHYD-DLC	\$179	\$203	\$235	\$273	\$316
Residential DHYD-Pricing	\$90	\$106	\$121	\$140	\$163
Weighted Average Res	\$166	\$184	\$189	\$219	\$254
Weighted Average Cost EI	\$82	\$102	\$117	\$134	\$154

3.2.2 Demand Response Results by Eastern Interconnection RTO/ISO Planning Area

The following sections present results for each RTO/ISO planning area. Note that the dollar amounts shown are nominal dollars throughout the report.

3.2.2.1 Entergy

Figure 3-13 and Table 3-16 present the demand-response potential by program type and customer class for Entergy. Savings from the C&I class are slightly larger than the residential sector. Within the C&I class, the largest programs are Curtailable/Interruptible and Other. Dynamic pricing and DLC account for a small amount of savings. Within the residential sector, direct load control (DLC) programs account for more than half the savings throughout the forecast period. Dynamic pricing also makes a significant contribution to residential savings.

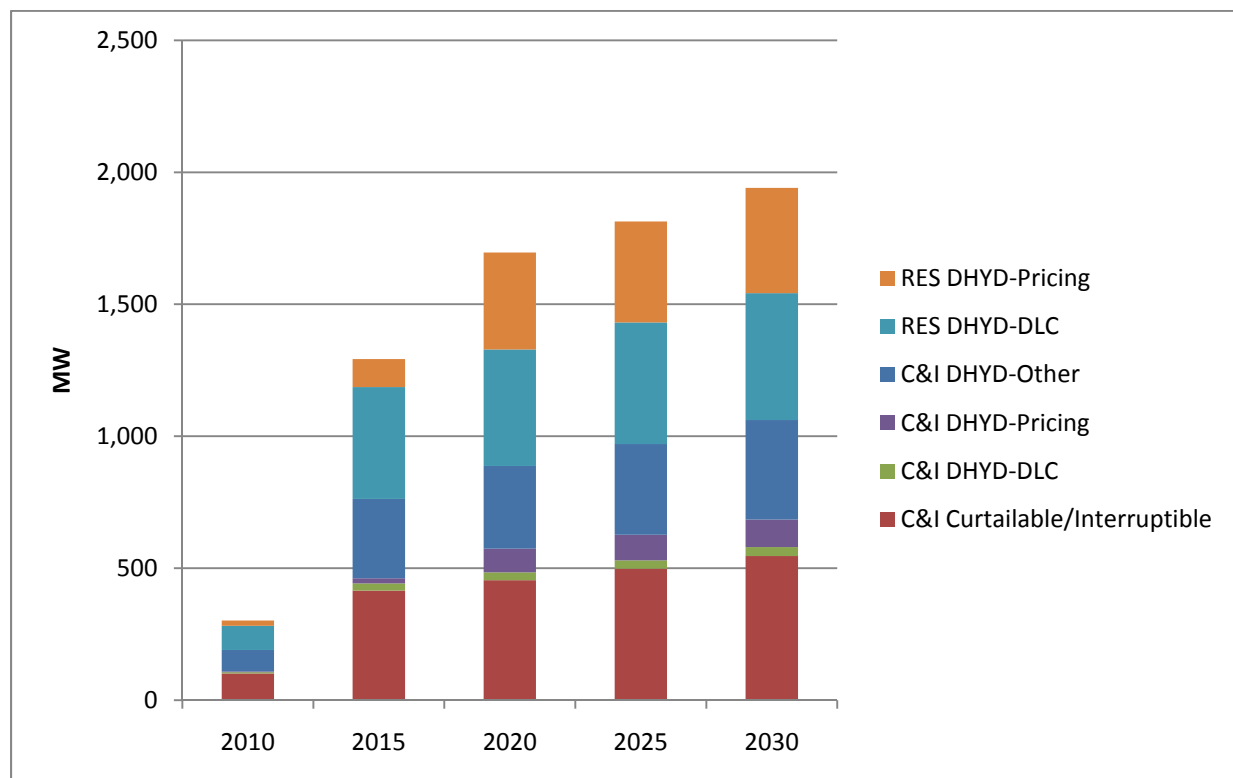
Figure 3-13 Demand Response Potential by Program for Entergy (MW)

Table 3-16 Entergy – Demand Savings by Program Type (MW)

Program	2010	2015	2020	2025	2030
C&I Curtailable/Interruptible	101	415	455	498	546
C&I DHYD-DLC	5	27	29	32	34
C&I DHYD-Pricing	3	20	90	97	104
C&I DHYD-Other	81	301	313	344	377
Total C&I	190	762	887	970	1,061
ES DHYD-DLC	92	424	442	461	481
RES DHYD-Pricing	20	106	367	383	399
Total RES	112	530	809	843	880
Total DR Entergy	302	1,292	1,696	1,814	1,941

Table 3-17 shows the estimate of budget, in nominal dollars, required to implement the demand response program in order to achieve the savings. Table 3-18 shows the average cost in nominal dollars for capturing the incremental impact from the demand response program. As participation in the programs reaches saturation, the average cost per kW saved increases.

Table 3-17 Entergy – Program Budget Requirement (\$ millions)

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$3,112	\$15,125	\$19,210	\$24,400	\$30,991
C&I DHYD-DLC	\$328	\$2,053	\$2,567	\$3,209	\$4,013
C&I DHYD-Pricing	\$171	\$1,336	\$6,955	\$8,689	\$10,855
C&I DTHR-Other	\$2,633	\$11,014	\$13,316	\$16,935	\$21,536
Total C&I	\$6,244	\$29,527	\$42,049	\$53,233	\$67,395
RES DHYD-DLC	\$13,960	\$75,318	\$90,943	\$109,912	\$132,963
RES DHYD-Pricing	\$1,651	\$9,885	\$38,871	\$46,914	\$56,673
Total Residential	\$15,611	\$85,202	\$129,814	\$156,826	\$189,636
Total DR Entergy	\$21,855	\$114,729	\$171,863	\$210,059	\$257,031

Table 3-18 Entergy – Average Cost per kW Saved

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$31	\$36	\$42	\$49	\$57
C&I DHYD-DLC	\$65	\$76	\$88	\$102	\$118
C&I DHYD-Pricing	\$61	\$68	\$77	\$90	\$104
C&I DTHR-Other	\$32	\$37	\$43	\$49	\$57
Total C&I (weighted average)	\$189	\$217	\$250	\$290	\$336
RES DHYD-DLC	\$152	\$178	\$206	\$239	\$277
RES DHYD-Pricing	\$82	\$93	\$106	\$123	\$142
Total Residential (weighted average)	\$235	\$271	\$312	\$361	\$419
Total DR Entergy (weighted average)	\$424	\$488	\$562	\$651	\$754

3.2.2.2 IESO

Figure 3-14 and Table 3-19 present the demand-response potential by program type and customer class for IESO. Savings from the C&I class are larger than the residential sector. Within the C&I class, the largest programs are Curtailable/Interruptible and Other. Dynamic pricing and DLC account for a very small amount of savings. Within the residential sector, direct load control (DLC) programs account for the majority of savings throughout the forecast period. Dynamic pricing makes a significant contribution to residential savings starting in 2020 once the programs are up and running.

Figure 3-14 Demand Response Potential by Program for IESO (MW)

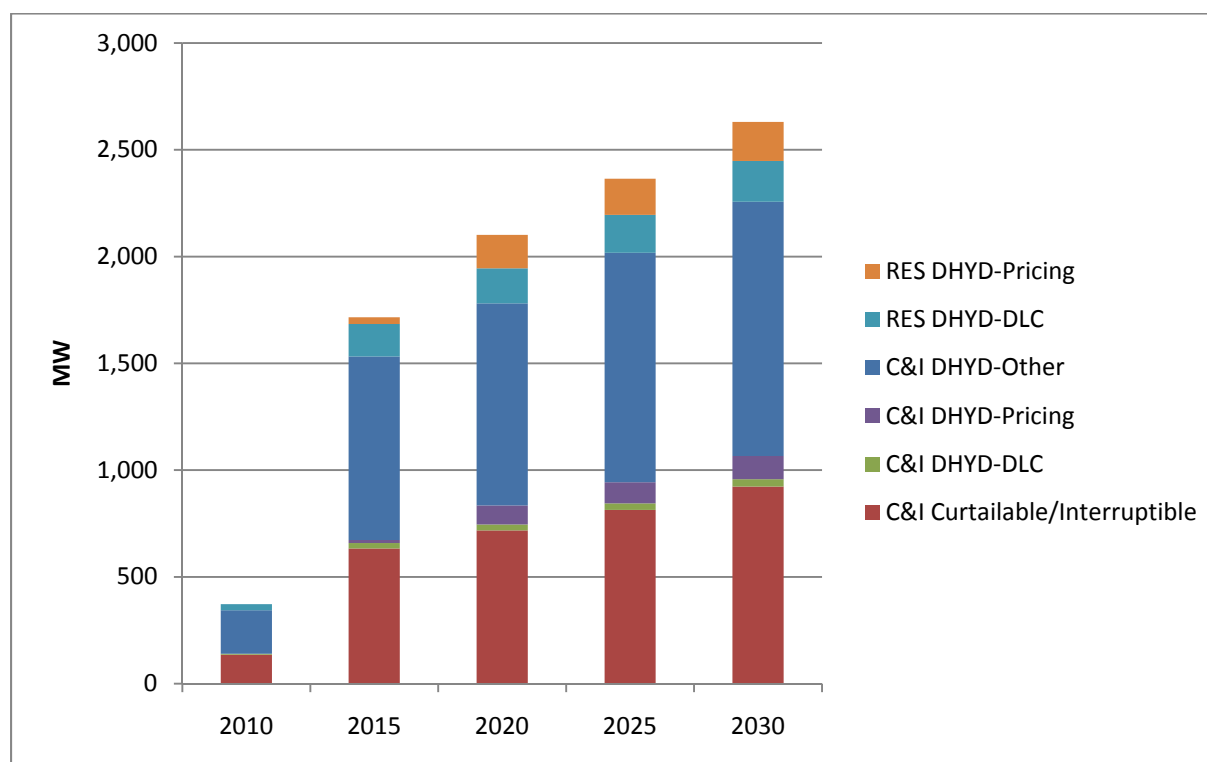


Table 3-19 IESO –Demand Savings by Program Type (MW)

Program	2010	2015	2020	2025	2030
C&I Curtailable/Interruptible	136	633	718	814	923
C&I DHYD-DLC	5	25	28	31	34
C&I DHYD-Pricing	0	14	89	98	109
C&I DHYD-Other	204	860	922	1,048	1,191
Total C&I	344	1,532	1,757	1,991	2,257
RES DHYD-DLC	28	152	164	177	191
RES DHYD-Pricing	0	31	157	169	183
Total RES	28	184	321	347	374
Total DR IESO	372	1,716	2,078	2,338	2,631

Table 3-20 shows the estimate of budget, in nominal dollars, required to implement the demand response program in order to achieve the savings.

Table 3-21 shows the average cost in nominal dollars for capturing the incremental impact from the demand response program. As participation in the programs reaches saturation, the average cost per kW saved increases.

Table 3-20 IESO – Program Budget Requirement (\$ millions)

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$5,313	\$28,723	\$37,751	\$49,629	\$65,261
C&I DHYD-DLC	\$366	\$2,347	\$3,007	\$3,852	\$4,935
C&I DHYD-Pricing	\$0	\$1,194	\$8,630	\$11,056	\$14,164
C&I DTHR-Other	\$7,973	\$39,004	\$48,509	\$63,891	\$84,170
Total C&I	\$13,653	\$71,267	\$97,895	\$128,427	\$168,530
RES DHYD-DLC	\$5,349	\$33,459	\$41,857	\$52,362	\$65,505
RES DHYD-Pricing	\$0	\$3,542	\$20,644	\$25,825	\$32,306
Total Residential	\$5,349	\$37,002	\$62,501	\$78,187	\$97,811
Total DR IESO	\$19,002	\$108,268	\$160,396	\$206,615	\$266,341

Table 3-21 IESO – Average Cost per kW Saved

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$39	\$45	\$53	\$61	\$71
C&I DHYD-DLC	\$80	\$93	\$108	\$125	\$145
C&I DHYD-Pricing	\$0	\$84	\$97	\$112	\$130
C&I DTHR-Other	\$39	\$45	\$51	\$59	\$71
Total C&I (weighted average)	\$159	\$267	\$309	\$358	\$417
RES DHYD-DLC	\$190	\$220	\$255	\$295	\$342
RES DHYD-Pricing	\$0	\$113	\$132	\$152	\$177
Total Residential (weighted average)	\$190	\$333	\$386	\$448	\$519
Total DR IESO (weighted average)	\$348	\$601	\$695	\$806	\$936

3.2.2.3 ISO-NE

Figure 3-15 and Table 3-22 present the demand-response potential by program type and customer class for ISO-NE. Savings from the C&I class are significantly larger than the residential sector. Within the C&I class, the largest programs are Curtailable/Interruptible and Other. Dynamic pricing and DLC account for a small amount of savings. Within the residential sector, direct load control (DLC) programs account for more than half the savings throughout the forecast period. By 2020, dynamic pricing also makes a significant contribution to residential savings.

Figure 3-15 Demand Response Potential by Program for ISO-NE (MW)

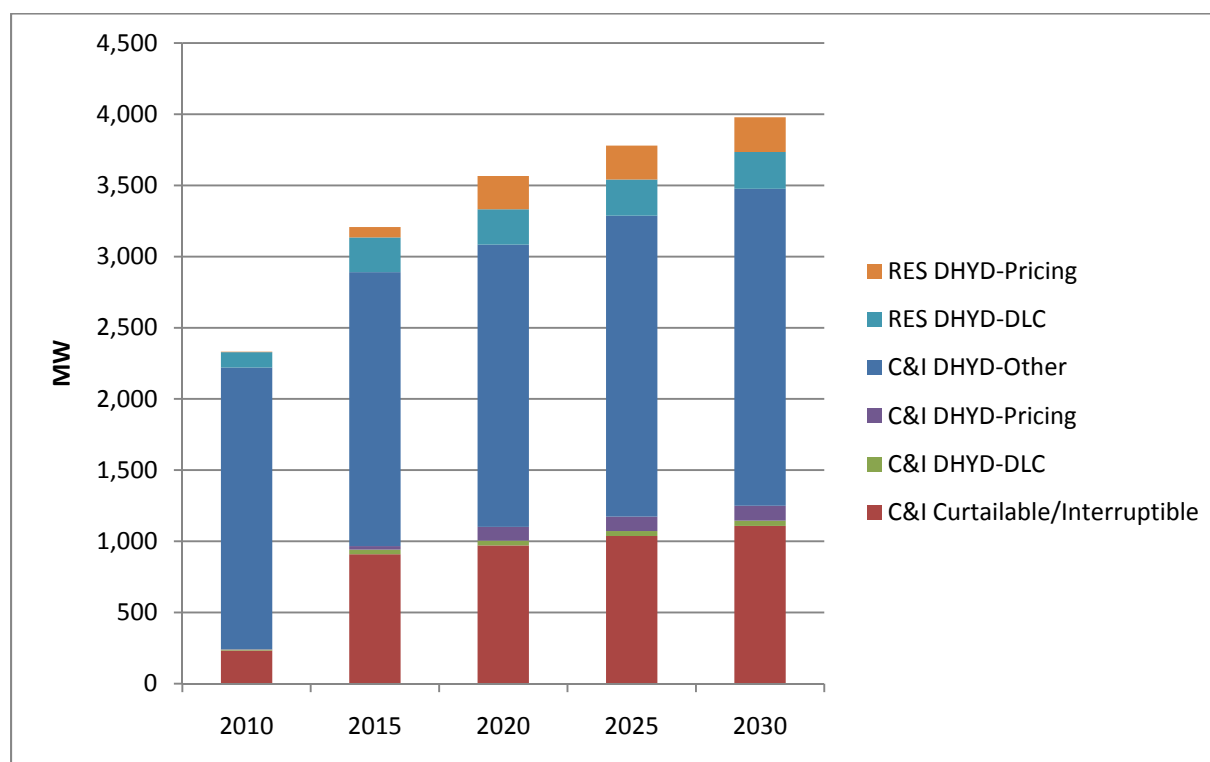


Table 3-22 ISO-NE –Demand Savings by Program Type (MW)

Program	2010	2015	2020	2025	2030
C&I Curtailable/Interruptible	233	909	971	1,037	1,109
C&I DHYD-DLC	6	32	34	35	36
C&I DHYD-Pricing	3	25	96	101	105
C&I DHYD-Other	1,979	1,924	1,983	2,114	2,226
Total C&I	2,221	2,891	3,084	3,287	3,476
RES DHYD-DLC	108	244	248	253	259
RES DHYD-Pricing	4	72	234	239	244
Total RES	112	316	483	493	503
Total DR ISO-NE	2,332	3,207	3,567	3,780	3,979

Table 3-23 shows the estimate of budget, in nominal dollars, required to implement the demand response program in order to achieve the savings. Table 3-24 shows the average cost in nominal dollars for capturing the incremental impact from the demand response program. As participation in the programs reaches saturation, the average cost per kW saved increases.

Table 3-23 ISO-NE - Program Budget Requirement (\$ millions)

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$9,856	\$47,029	\$58,162	\$71,947	\$89,021
C&I DHYD-DLC	\$561	\$3,391	\$4,097	\$4,950	\$5,982
C&I DHYD-Pricing	\$170	\$2,331	\$10,374	\$12,563	\$15,216
C&I DTHR-Other	\$87,571	\$98,338	\$115,879	\$143,145	\$176,844
Total C&I	\$98,158	\$151,089	\$188,512	\$232,605	\$287,063
RES DHYD-DLC	\$23,694	\$62,702	\$74,118	\$87,616	\$103,577
RES DHYD-Pricing	\$334	\$9,686	\$36,195	\$42,804	\$50,623
Total Residential	\$24,028	\$72,388	\$110,313	\$130,421	\$154,200
Total DR ISO-NE	\$122,186	\$223,476	\$298,825	\$363,026	\$441,263

Table 3-24 ISO-NE – Average Cost per kW Saved

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$42	\$52	\$60	\$69	\$80
C&I DHYD-DLC	\$91	\$105	\$122	\$141	\$164
C&I DHYD-Pricing	\$63	\$92	\$108	\$125	\$145
C&I DTHR-Other	\$44	\$51	\$58	\$68	\$79
Total C&I (weighted average)	\$241	\$300	\$348	\$403	\$468
RES DHYD-DLC	\$220	\$257	\$298	\$346	\$401
RES DHYD-Pricing	\$84	\$134	\$154	\$179	\$207
Total Residential (weighted average)	\$304	\$391	\$453	\$525	\$608
Total DR ISO-NE (weighted average)	\$545	\$691	\$801	\$928	\$1,076

3.2.2.4 MAPP

Figure 3-16 and Table 3-25 present the demand-response potential by program type and customer class for MAPP. Savings from the C&I class are slightly larger than the residential sector for most of the forecast period. Within the C&I class, the largest programs are Other. Dynamic pricing, curtailable/interruptible, and DLC programs account for a small amount of savings. Within the residential sector, direct load control (DLC) programs account for more most of the savings throughout the forecast period.

Figure 3-16 Demand Response Potential by Program for MAPP (MW)

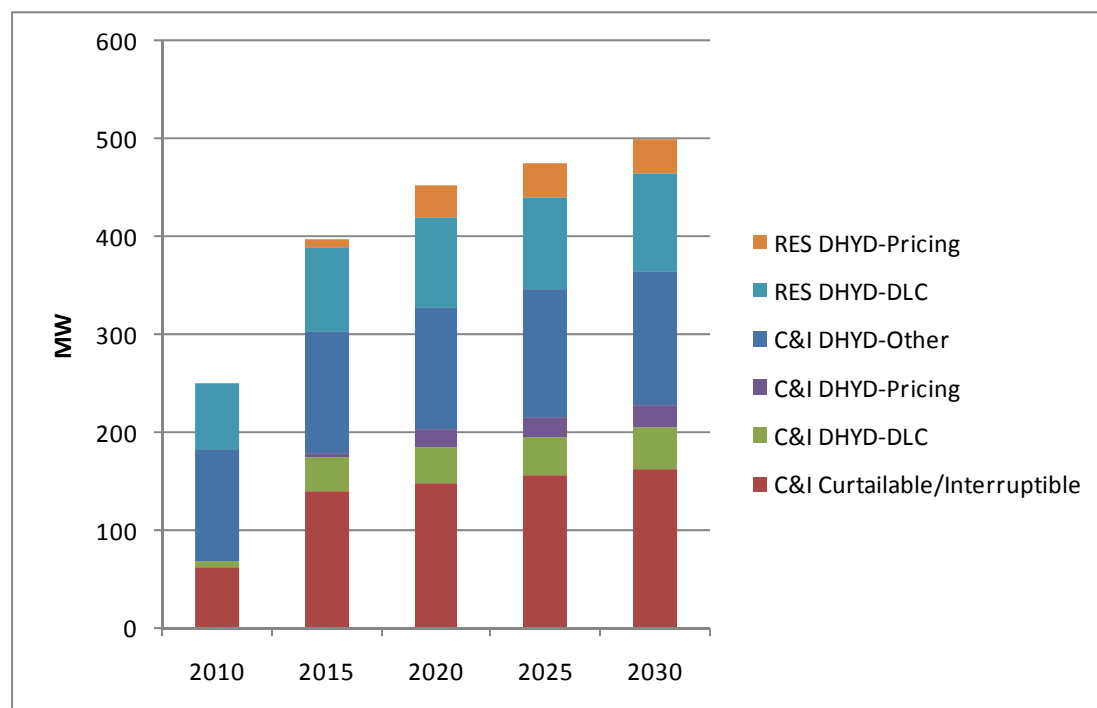


Table 3-25 MAPP –Demand Savings by Program Type (MW)

Program	2010	2015	2020	2025	2030
C&I Curtailable/Interruptible	62	140	148	155	163
C&I DHYD-DLC	6	35	37	40	43
C&I DHYD-Pricing	0	4	18	20	21
C&I DHYD-Other	115	124	125	131	137
Total C&I	184	303	328	346	364
RES DHYD-DLC	66	86	91	96	100
RES DHYD-Pricing	0	8	33	34	35
Total RES	66	94	124	130	136
Total DR MAPP	249	397	452	475	500

Table 3-26 shows the estimate of budget, in nominal dollars, required to implement the demand response program in order to achieve the savings. Table 3-27 shows the average cost in nominal dollars for capturing the incremental impact from the demand response program. As participation in the programs reaches saturation, the average cost per kW saved increases.

Table 3-26 MAPP – Program Budget Requirement (\$ millions)

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$3,716	\$9,617	\$11,754	\$14,291	\$17,412
C&I DHYD-DLC	\$461	\$2,893	\$3,605	\$4,481	\$5,551
C&I DHYD-Pricing	\$0	\$341	\$1,773	\$2,194	\$2,709
C&I DTHR-Other	\$6,980	\$8,578	\$9,981	\$12,109	\$14,735
Total C&I	\$11,157	\$21,429	\$27,113	\$33,075	\$40,407
RES DHYD-DLC	\$12,402	\$18,848	\$23,024	\$27,995	\$34,014
RES DHYD-Pricing	\$0	\$865	\$4,214	\$5,103	\$6,164
Total Residential	\$12,402	\$19,714	\$27,237	\$33,098	\$40,178
Total DR MAPP	\$23,559	\$41,143	\$54,350	\$66,173	\$80,585

Table 3-27 MAPP – Average Cost per kW Saved

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$60	\$69	\$79	\$92	\$107
C&I DHYD-DLC	\$72	\$84	\$97	\$112	\$130
C&I DHYD-Pricing	\$0	\$83	\$96	\$111	\$129
C&I DTHR-Other	\$61	\$69	\$80	\$93	\$107
Total C&I (weighted average)	\$193	\$304	\$352	\$408	\$473
RES DHYD-DLC	\$188	\$218	\$253	\$293	\$340
RES DHYD-Pricing	\$0	\$112	\$129	\$150	\$174
Total Residential (weighted average)	\$188	\$330	\$382	\$443	\$513
Total DR MAPP (weighted average)	\$381	\$635	\$734	\$851	\$987

3.2.2.5 MRO-Canada

Figure 3-17 and Table 3-28 present the demand-response potential by program type and customer class for MRO-Canada. Savings from the C&I class are slightly larger than the residential sector. Within the C&I class, the largest programs are Curtailable/Interruptible and Other. Dynamic pricing and DLC account for a very small amount of savings. Within the residential sector, direct load control (DLC) programs account for most of the savings throughout the forecast period.

Figure 3-17 Demand Response Potential by Program for MRO-Canada (MW)

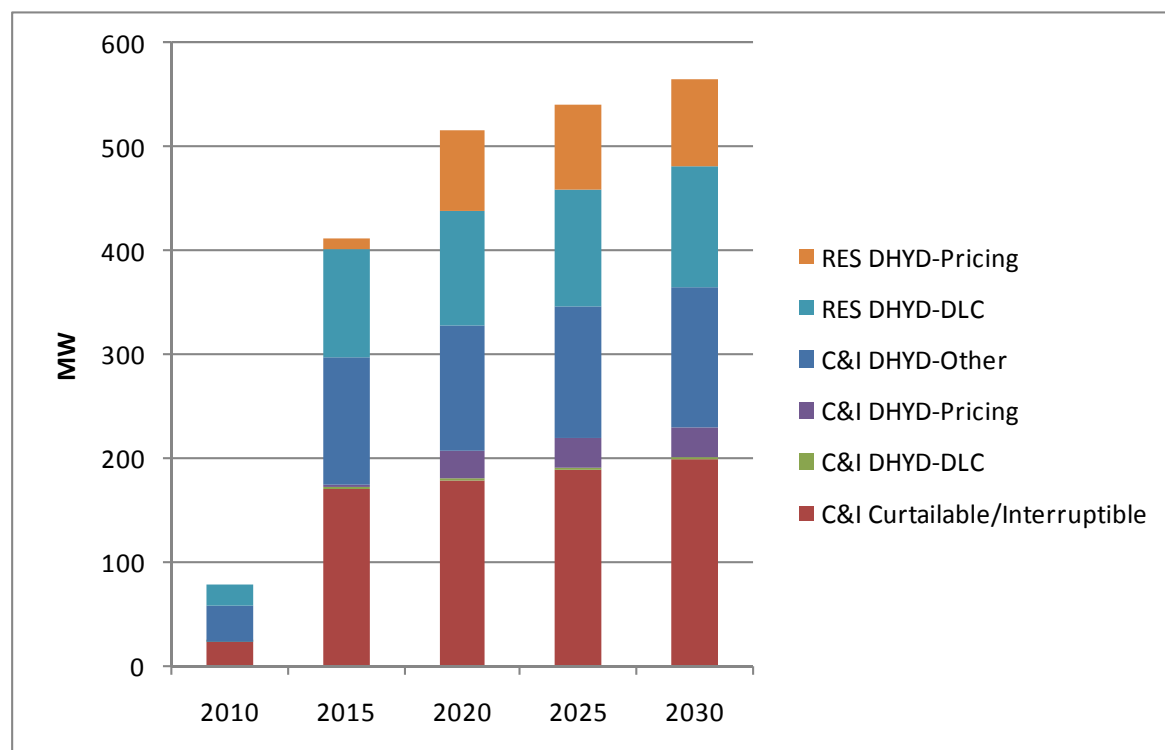


Table 3-28 MRO-Canada –Demand Savings by Program Type (MW)

Program	2010	2015	2020	2025	2030
C&I Curtailable/Interruptible	23	170	179	189	199
C&I DHYD-DLC	0	2	2	3	3
C&I DHYD-Pricing	0	3	26	27	28
C&I DHYD-Other	35	122	121	128	134
Total C&I	58	297	329	346	364
RES DHYD-DLC	20	105	109	113	117
RES DHYD-Pricing	0	10	79	82	84
Total RES	20	115	188	194	201
Total DR MRO-Canada	78	412	516	541	565

Table 3-29 shows the estimate of budget, in nominal dollars, required to implement the demand response program in order to achieve the savings. Table 3-30 shows the average cost in nominal dollars for capturing the incremental impact from the demand response program. As participation in the programs reaches saturation, the average cost per kW saved increases.

Table 3-29 MRO-Canada – Program Budget Requirement (\$ millions)

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$1,211	\$10,557	\$12,884	\$15,809	\$19,342
C&I DHYD-DLC	\$33	\$209	\$250	\$299	\$358
C&I DHYD-Pricing	\$0	\$237	\$2,558	\$3,051	\$3,637
C&I DTHR-Other	\$1,856	\$7,528	\$8,678	\$10,669	\$13,077
Total C&I	\$3,101	\$18,531	\$24,371	\$29,828	\$36,413
RES DHYD-DLC	\$3,829	\$23,066	\$27,735	\$33,290	\$39,893
RES DHYD-Pricing	\$0	\$1,152	\$10,353	\$12,425	\$14,888
Total Residential	\$3,829	\$24,218	\$38,089	\$45,715	\$54,781
Total DR MRO Canada	\$6,930	\$42,750	\$62,459	\$75,543	\$91,195

Table 3-30 MRO-Canada – Average Cost per kW Saved

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$53	\$62	\$72	\$84	\$97
C&I DHYD-DLC	\$76	\$88	\$102	\$119	\$138
C&I DHYD-Pricing	\$0	\$84	\$97	\$112	\$130
C&I DTHR-Other	\$53	\$62	\$72	\$84	\$97
Total C&I (weighted average)	\$182	\$296	\$343	\$398	\$463
RES DHYD-DLC	\$190	\$220	\$255	\$295	\$342
RES DHYD-Pricing	\$0	\$113	\$132	\$152	\$177
Total Residential (weighted average)	\$190	\$333	\$386	\$448	\$519
Total DR MRO-Canada (weighted average)	\$372	\$629	\$729	\$846	\$982

3.2.2.6 NYISO

Table 3-31 and Figure 3-18 present the demand-response potential by program type and customer class for NYISO. Savings from the C&I class are significantly larger than the residential sector. Within the C&I class, the largest programs are Other DR programs followed by Curtailable/Interruptible. Dynamic pricing and DLC account for a small amount of savings. Within the residential sector, direct load control (DLC) programs account for more than half the savings throughout the forecast period. Dynamic pricing also makes a significant contribution to residential savings by the end of the forecast period.

Figure 3-18 Demand Response Potential by Program for NYISO (MW)

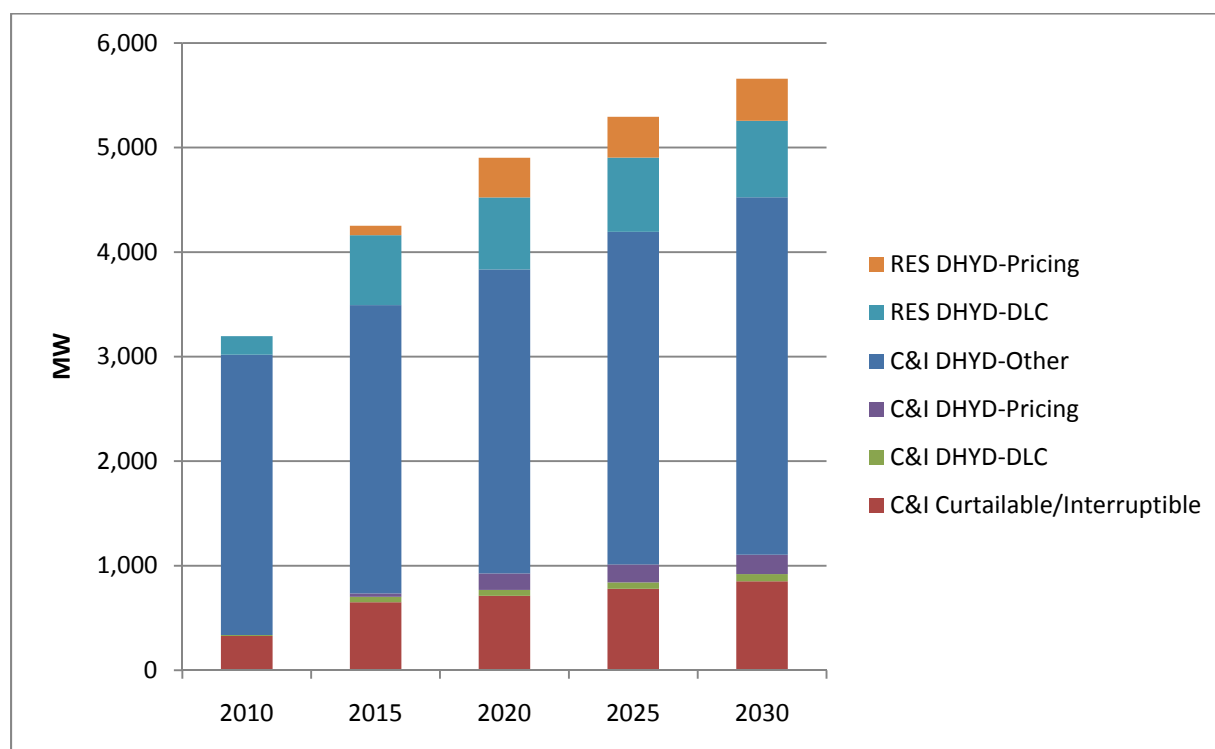


Table 3-31 NYISO –Demand Savings by Program Type (MW)

Program	2010	2015	2020	2025	2030
C&I Curtailable/Interruptible	327	651	712	779	852
C&I DHYD-DLC	10	52	57	62	68
C&I DHYD-Pricing	0	31	158	171	186
C&I DHYD-Other	2,681	2,758	2,907	3,181	3,419
Total C&I	3,018	3,493	3,834	4,194	4,525
RES DHYD-DLC	178	669	689	710	731
RES DHYD-Pricing	0	91	380	391	403
Total RES	178	760	1,069	1,101	1,134
Total DR NYISO	3,196	4,253	4,903	5,295	5,659

Table 3-32 shows the estimate of budget, in nominal dollars, required to implement the demand response program in order to achieve the savings. Table 3-33 shows the average cost in nominal dollars for capturing the incremental impact from the demand response program. As participation in the programs reaches saturation, the average cost per kW saved increases.

Table 3-32 NYISO – Program Budget Requirement (\$ millions)

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$14,397	\$33,195	\$42,093	\$53,376	\$67,684
C&I DHYD-DLC	\$871	\$5,493	\$6,927	\$8,737	\$11,019
C&I DHYD-Pricing	\$0	\$2,941	\$17,157	\$21,639	\$27,292
C&I DTHR-Other	\$117,954	\$140,669	\$168,824	\$214,167	\$271,687
Total C&I (weighted average)	\$133,223	\$182,297	\$235,001	\$297,919	\$377,682
RES DHYD-DLC	\$37,873	\$165,269	\$197,320	\$235,585	\$281,272
RES DHYD-Pricing	\$0	\$11,578	\$56,160	\$67,051	\$80,054
Total Residential (weighted average)	\$37,873	\$176,848	\$253,480	\$302,636	\$361,326
Total DR NYISO (weighted average)	\$171,096	\$359,145	\$488,481	\$600,555	\$739,008

Table 3-33 NYISO – Average Cost per kW Saved

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$44	\$51	\$59	\$69	\$79
C&I DHYD-DLC	\$90	\$105	\$121	\$141	\$163
C&I DHYD-Pricing	\$0	\$94	\$109	\$126	\$146
C&I DTHR-Other	\$44	\$51	\$58	\$67	\$79
Total C&I (weighted average)	\$178	\$301	\$347	\$403	\$468
RES DHYD-DLC	\$213	\$247	\$286	\$332	\$385
RES DHYD-Pricing	\$0	\$128	\$148	\$171	\$199
Total Residential (weighted average)	\$213	\$374	\$434	\$503	\$583
Total DR NYISO (weighted average)	\$391	\$675	\$782	\$906	\$1,052

3.2.2.7 PJM

Figure 3-19 and Table 3-34 present the demand-response potential by program type and customer class for PJM. Savings from the C&I class are larger than the residential sector. Within the C&I class, the largest programs are Curtailable/Interruptible and Other. Dynamic pricing and DLC account for a small amount of savings. Within the residential sector, direct load control (DLC) programs account for more than half the savings throughout the forecast period. Dynamic pricing also makes a significant contribution to residential savings.

Figure 3-19 Demand Response Potential by Program for PJM (MW)

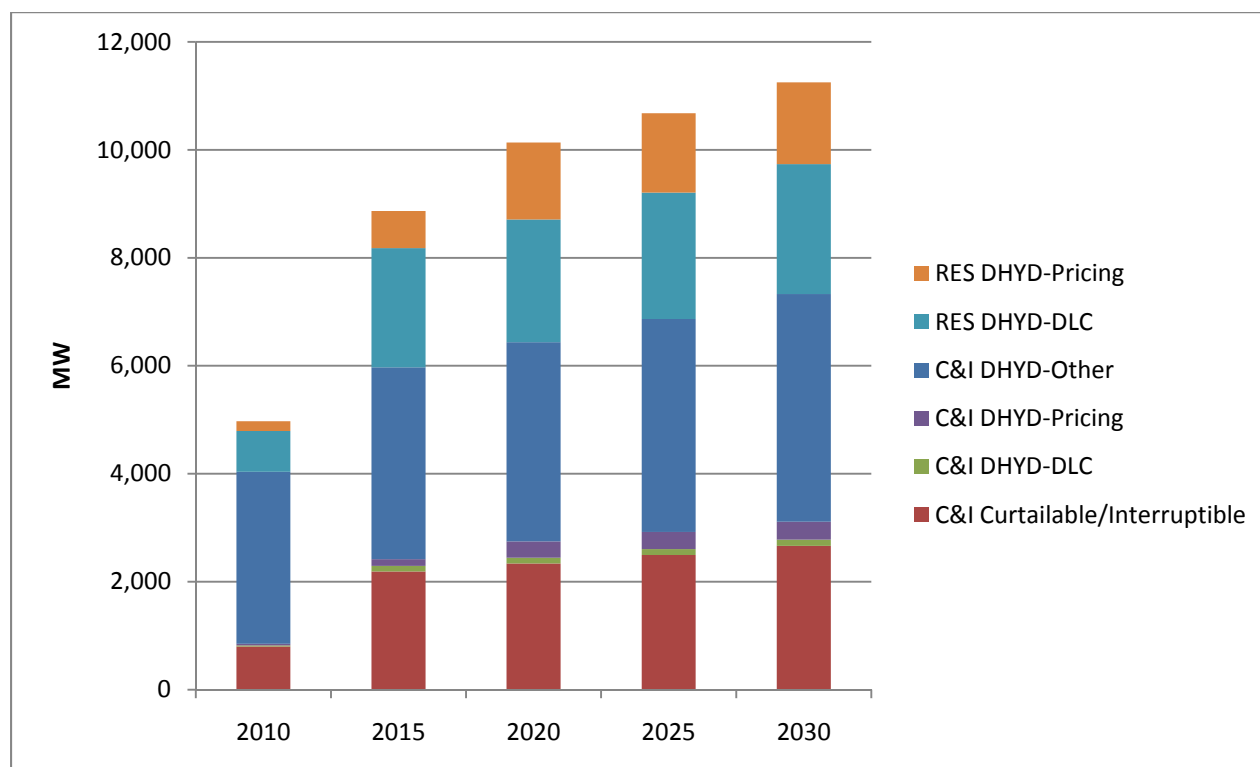


Table 3-34 PJM – Demand Savings by Program Type (MW)

Program	2010	2015	2020	2025	2030
C&I Curtailable/Interruptible	800	2,190	2,336	2,493	2,662
C&I DHYD-DLC	20	102	107	111	116
C&I DHYD-Pricing	30	125	304	317	332
C&I DHYD-Other	3,186	3,556	3,691	3,945	4,218
Total C&I	4,036	5,973	6,438	6,867	7,328
RES DHYD-DLC	757	2,206	2,273	2,340	2,408
RES DHYD-Pricing	179	689	1,425	1,470	1,516
Total RES	936	2,896	3,698	3,810	3,924
Total DR PJM	4,972	8,868	10,136	10,677	11,252

Table 3-35 shows the estimate of budget, in nominal dollars, required to implement the demand response program in order to achieve the savings. Table 3-36 shows the average cost in nominal dollars for capturing the incremental impact from the demand response program. As participation in the programs reaches saturation, the average cost per kW saved increases.

Table 3-35 PJM – Program Budget Requirement (\$ millions)

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$29,451	\$94,564	\$116,870	\$144,497	\$178,731
C&I DHYD-DLC	\$1,579	\$9,562	\$11,572	\$14,015	\$16,987
C&I DHYD-Pricing	\$2,217	\$10,403	\$28,852	\$34,937	\$42,332
C&I DTHR-Other	\$126,457	\$162,108	\$195,097	\$241,581	\$299,219
Total C&I	\$159,704	\$276,638	\$352,391	\$435,030	\$537,268
RES DHYD-DLC	\$150,245	\$488,886	\$584,768	\$699,153	\$835,511
RES DHYD-Pricing	\$18,514	\$81,074	\$191,563	\$229,512	\$274,916
Total Residential	\$168,759	\$569,960	\$776,331	\$928,665	\$1,110,428
Total DR PJM	\$328,463	\$846,598	\$1,128,722	\$1,363,695	\$1,647,695

Table 3-36 PJM – Average Cost per kW Saved

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$37	\$43	\$50	\$58	\$67
C&I DHYD-DLC	\$81	\$94	\$109	\$126	\$146
C&I DHYD-Pricing	\$73	\$83	\$95	\$110	\$128
C&I DTHR-Other	\$40	\$46	\$52	\$60	\$71
Total C&I (weighted average)	\$231	\$266	\$306	\$354	\$412
RES DHYD-DLC	\$199	\$222	\$257	\$299	\$347
RES DHYD-Pricing	\$103	\$118	\$134	\$156	\$181
Total Residential (weighted average)	\$302	\$339	\$392	\$455	\$528
Total DR PJM (weighted average)	\$532	\$605	\$697	\$809	\$940

3.2.2.8 SERC

Figure 3-20 and Table 3-37 present the demand-response potential by program type and customer class for SERC. Savings from the C&I class are larger than the residential sector. Within the C&I class, the largest programs are Curtailable/Interruptible and Other. Dynamic pricing and DLC account for a small amount of savings. Within the residential sector, direct load control (DLC) programs account for more than half the savings throughout the forecast period. Dynamic pricing also makes a significant contribution to residential savings.

Figure 3-20 Demand Response Potential by Program for SERC (MW)

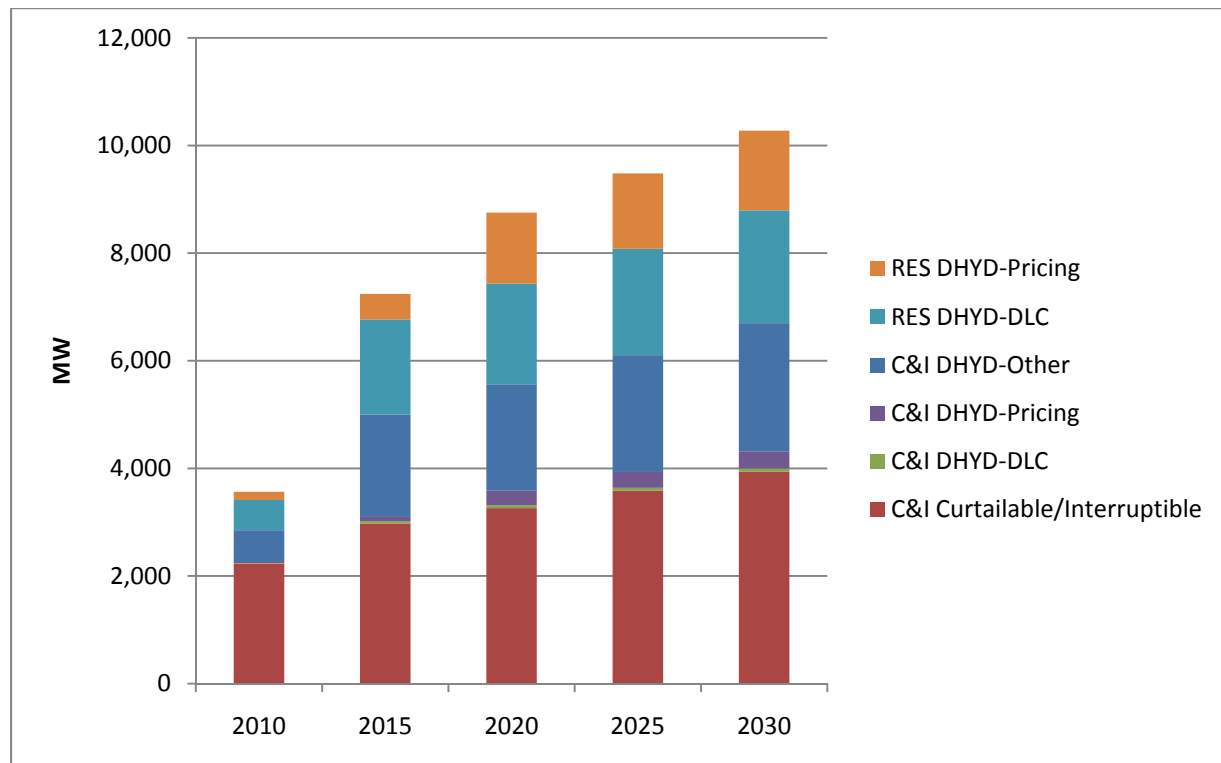


Table 3-37 SERC –Demand Savings by Program Type (MW)

Program	2010	2015	2020	2025	2030
C&I Curtailable/Interruptible	2,230	2,970	3,263	3,585	3,938
C&I DHYD-DLC	9	48	51	55	60
C&I DHYD-Pricing	22	81	273	295	319
C&I DHYD-Other	593	1,900	1,975	2,170	2,383
Total C&I	2,853	4,998	5,563	6,105	6,699
RES DHYD-DLC	561	1,768	1,869	1,978	2,094
RES DHYD-Pricing	151	476	1,322	1,399	1,482
Total RES	713	2,244	3,192	3,377	3,576
Total DR SERC	3,566	7,242	8,754	9,482	10,275

Table 3-38 shows the estimate of budget, in nominal dollars, required to implement the demand response program in order to achieve the savings. Table 3-38 shows the average cost in nominal dollars for capturing the incremental impact from the demand response program. As participation in the programs reaches saturation, the average cost per kW saved increases.

Table 3-38 SERC – Program Budget Requirement (\$ millions)

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$68,289	\$105,282	\$134,085	\$170,768	\$217,487
C&I DHYD-DLC	\$557	\$3,483	\$4,358	\$5,455	\$6,828
C&I DHYD-Pricing	\$1,230	\$5,303	\$20,734	\$25,977	\$32,547
C&I DTHR-Other	\$18,474	\$68,256	\$82,253	\$104,716	\$133,313
Total C&I	\$88,550	\$182,324	\$241,431	\$306,916	\$390,175
RES DHYD-DLC	\$84,261	\$305,202	\$374,347	\$459,430	\$564,178
RES DHYD-Pricing	\$11,635	\$42,313	\$136,018	\$166,957	\$205,043
Total Residential	\$95,897	\$347,515	\$510,366	\$626,387	\$769,221
Total DR SERC	\$184,446	\$529,838	\$751,796	\$933,303	\$1,159,396

Table 3-39 SERC – Average Cost per kW Saved

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$31	\$35	\$41	\$48	\$55
C&I DHYD-DLC	\$63	\$73	\$85	\$98	\$114
C&I DHYD-Pricing	\$57	\$66	\$76	\$88	\$102
C&I DTHR-Other	\$31	\$36	\$41	\$47	\$56
Total C&I (weighted average)	\$182	\$210	\$243	\$282	\$328
RES DHYD-DLC	\$150	\$173	\$200	\$232	\$269
RES DHYD-Pricing	\$77	\$89	\$103	\$119	\$138
Total Residential (weighted average)	\$227	\$262	\$303	\$352	\$408
Total DR SERC (weighted average)	\$409	\$472	\$546	\$633	\$735

3.2.2.9 SPP

Figure 3-21 and Table 3-40 present the demand-response potential by program type and customer class for SPP. Savings from the C&I class are larger than the residential sector. Within the C&I class, the largest programs are Curtailable/Interruptible and Other. Dynamic pricing and DLC account for a small amount of savings. Within the residential sector, direct load control (DLC) programs account for more than half the savings throughout the forecast period. Dynamic pricing also makes a significant contribution to residential savings by the end of the forecast period.

Figure 3-21 Demand Response Potential by Program for SPP (MW)

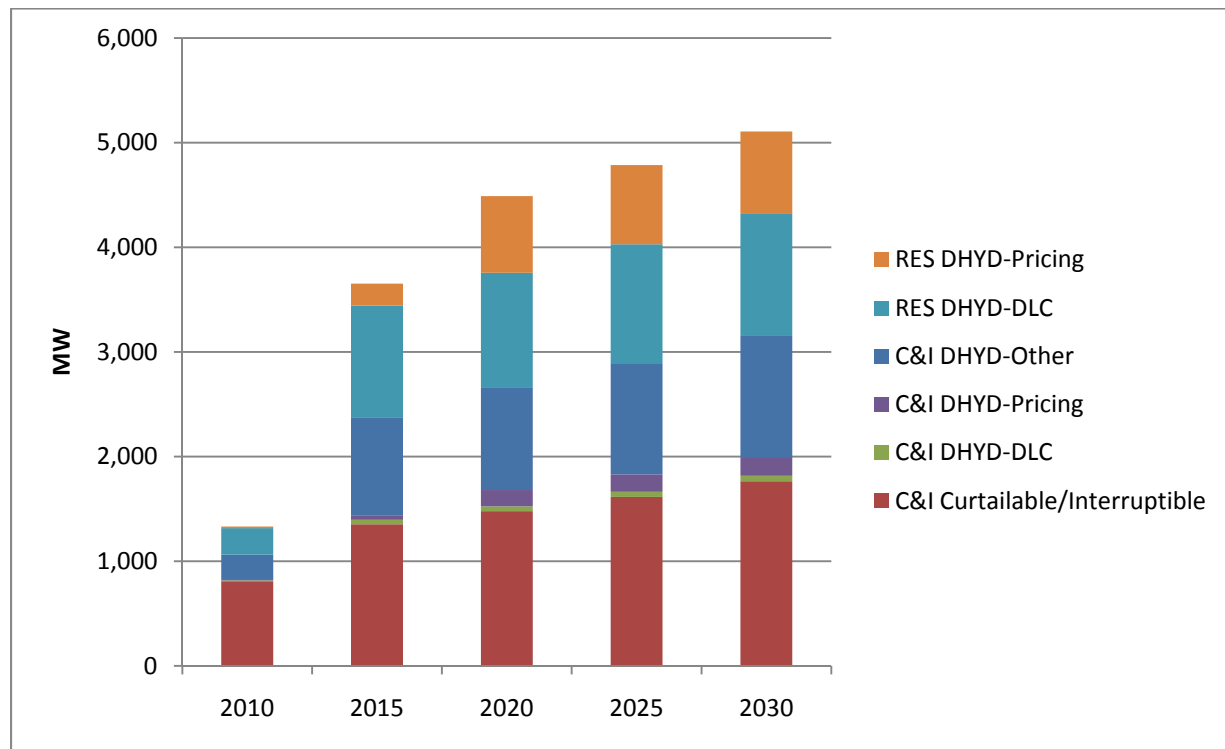


Table 3-40 SPP –Demand Savings by Program Type (MW)

Program	2010	2015	2020	2025	2030
C&I Curtailable/Interruptible	809	1,353	1,478	1,615	1,764
C&I DHYD-DLC	8	42	45	49	52
C&I DHYD-Pricing	4	39	156	167	179
C&I DHYD-Other	242	942	975	1,062	1,157
Total C&I	1,062	2,376	2,655	2,892	3,152
RES DHYD-DLC	254	1,068	1,101	1,136	1,173
RES DHYD-Pricing	15	210	733	756	781
Total RES	269	1,277	1,834	1,893	1,954
Total DR SPP	1,331	3,653	4,489	4,785	5,106

Table 3-41 shows the estimate of budget, in nominal dollars, required to implement the demand response program in order to achieve the savings. Table 3-42 shows the average cost in nominal dollars for capturing the incremental impact from the demand response program. As participation in the programs reaches saturation, the average cost per kW saved increases.

Table 3-41 SPP – Program Budget Requirement (\$ millions)

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$27,630	\$53,080	\$67,244	\$85,148	\$107,859
C&I DHYD-DLC	\$545	\$3,392	\$4,218	\$5,244	\$6,522
C&I DHYD-Pricing	\$247	\$2,820	\$12,972	\$16,113	\$20,021
C&I DTHR-Other	\$8,213	\$36,899	\$44,305	\$55,933	\$70,630
Total C&I	\$36,636	\$96,191	\$128,738	\$162,438	\$205,033
RES DHYD-DLC	\$41,068	\$201,205	\$240,643	\$287,881	\$344,558
RES DHYD-Pricing	\$1,325	\$20,491	\$82,803	\$99,036	\$118,514
Total Residential	\$42,393	\$221,696	\$323,446	\$386,917	\$463,072
Total DR SPP	\$79,028	\$317,887	\$452,184	\$549,355	\$668,105

Table 3-42 SPP– Average Cost per kW Saved

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$34	\$39	\$45	\$53	\$61
C&I DHYD-DLC	\$69	\$80	\$93	\$108	\$125
C&I DHYD-Pricing	\$65	\$72	\$83	\$96	\$112
C&I DTHR-Other	\$34	\$39	\$45	\$53	\$61
Total C&I (weighted average)	\$202	\$231	\$267	\$309	\$359
RES DHYD-DLC	\$162	\$188	\$218	\$253	\$294
RES DHYD-Pricing	\$88	\$98	\$113	\$131	\$152
Total Residential (weighted average)	\$250	\$286	\$331	\$384	\$445
Total DR SPP (weighted average)	\$452	\$517	\$598	\$694	\$804

3.2.2.10 TVA

Figure 3-22 and Table 3-43 present the demand-response potential by program type and customer class for TVA. Savings from the Residential class are slightly larger than the C&I sector by 2020. Within the C&I class, the largest programs are Curtailable/Interruptible and Other. Dynamic pricing and DLC account for a small amount of savings. Within the residential sector, direct load control (DLC) programs account for most of the savings throughout the forecast period. Dynamic pricing also makes a significant contribution to residential savings by the end of the forecast period.

Figure 3-22 Demand Response Potential by Program for TVA (MW)

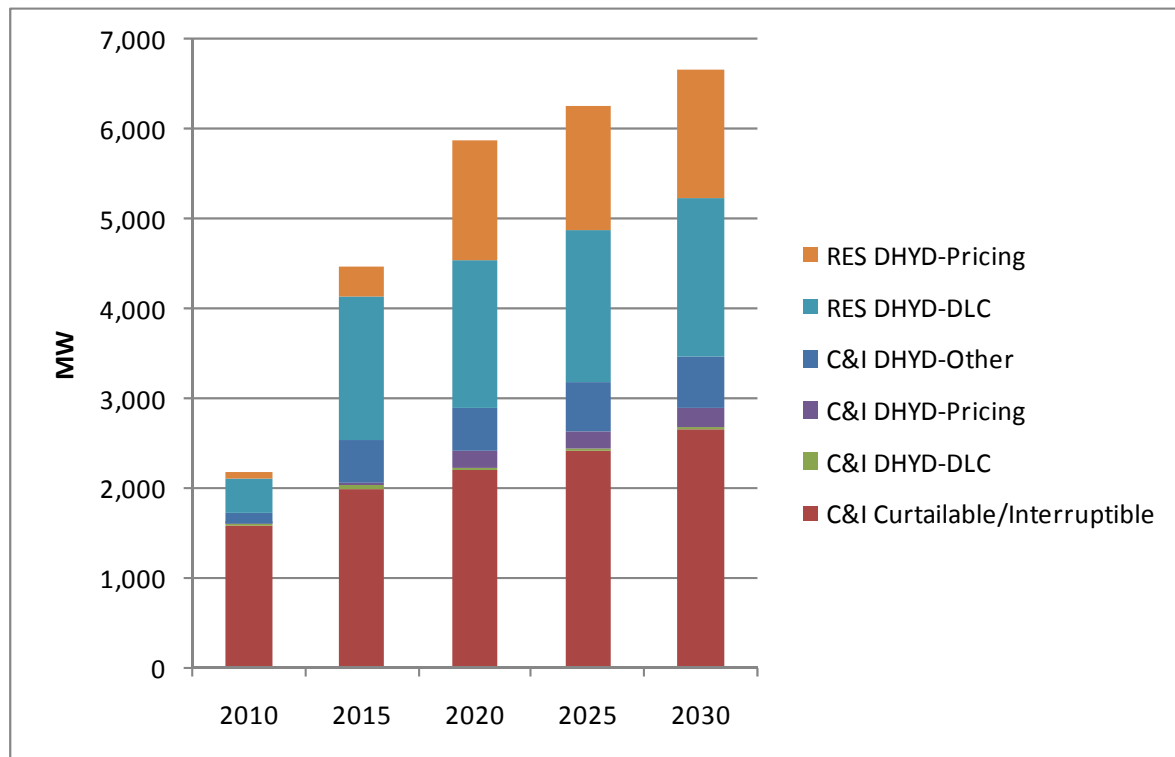


Table 3-43 TVA –Demand Savings by Program Type (MW)

Program	2010	2015	2020	2025	2030
C&I Curtailable/Interruptible	1,594	2,003	2,199	2,414	2,649
C&I DHYD-DLC	5	29	31	33	35
C&I DHYD-Pricing	6	35	181	193	206
C&I DHYD-Other	118	470	490	537	589
Total C&I	1,723	2,538	2,901	3,177	3,479
RES DHYD-DLC	384	1,589	1,639	1,690	1,744
RES DHYD-Pricing	78	348	1,345	1,388	1,433
Total RES	462	1,937	2,983	3,078	3,177
Total DR TVA	2,185	4,475	5,884	6,255	6,656

Table 3-44 shows the estimate of budget, in nominal dollars, required to implement the demand response program in order to achieve the savings. Table 3-45 shows the average cost in nominal dollars for capturing the incremental impact from the demand response program. As participation in the programs reaches saturation, the average cost per kW saved increases.

Table 3-44 TVA – Program Budget Requirement (\$ millions)

Program	2010	2015	2020	2025	2030
C&I DTHR-Interruptible/Curtailable	\$49,459	\$71,571	\$91,084	\$115,906	\$147,506
C&I DHYD-DLC	\$340	\$2,102	\$2,599	\$3,213	\$3,972
C&I DHYD-Pricing	\$256	\$2,298	\$13,650	\$16,874	\$20,860
C&I DTHR-Other	\$3,550	\$16,409	\$19,814	\$25,187	\$32,022
Total C&I	\$53,605	\$92,380	\$127,147	\$161,179	\$204,360
RES DHYD-DLC	\$54,813	\$262,439	\$313,930	\$375,555	\$449,352
RES DHYD-Pricing	\$5,065	\$29,248	\$132,521	\$158,690	\$190,058
Total Residential	\$59,878	\$291,686	\$446,451	\$534,245	\$639,410
Total DR TVA	\$113,483	\$384,067	\$573,598	\$695,424	\$843,769

Table 3-45 TVA – Average Cost per kW Saved

Program	2010	2015	2020	2025	2030
\$30	\$31	\$36	\$41	\$48	\$56
\$61	\$63	\$73	\$84	\$98	\$113
\$56	\$45	\$65	\$75	\$87	\$101
\$30	\$30	\$35	\$40	\$47	\$54
\$177	\$169	\$208	\$241	\$280	\$324
\$145	\$143	\$165	\$192	\$222	\$258
\$0	\$65	\$84	\$99	\$114	\$133
\$145	\$208	\$249	\$290	\$337	\$390
Total DR TVA (weighted average)	\$376	\$457	\$531	\$616	\$715

3.3 ENERGY EFFICIENCY FOR EASTERN INTERCONNECTION

This section presents the results of the energy-efficiency analysis for the Eastern Interconnection. The Eastern Interconnection results are exclusive of the energy-efficiency potential in the Midwest ISO region.

3.3.1 Summary of Energy Efficiency Results for Eastern Interconnection

Table 3-46 and Table 3-47 show the cumulative energy and demand savings from energy-efficiency programs within the Eastern Interconnection, respectively. Cumulative energy savings are projected to be over 250,000 GWh (over 12% of baseline energy consumption) by 2030. Cumulative demand savings due to energy-efficiency programs are projected to be over 48 GW (over 12% of baseline demand) by 2030. The PJM planning area will account for the largest amount of savings, followed by (in descending order) SERC, SPP, NYISO, TVA, ISO-NE, and IESO. This result is consistent with the fact that PJM has the largest number of customers in the Eastern Interconnection. The MAPP and MRO-Canada planning areas are not expected to contribute significantly to the savings potential within the Eastern Interconnection due to the relatively small customer population.

Table 3-46 Energy Efficiency – Cumulative Energy Savings Potential

RTO/ISO	Cumulative Energy Savings (GWh)					Percentage of Baseline				
	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
Entergy	280	4,436	8,553	9,971	10,543	0.3%	4.1%	7.6%	8.4%	8.5%
IESO (Canada)	1,183	8,555	14,615	17,054	18,301	0.9%	6.1%	10.0%	11.2%	11.6%
ISO-NE	1,511	10,630	17,765	20,506	21,829	1.2%	8.4%	13.6%	15.2%	15.8%
MAPP	49	840	1,653	1,956	2,073	0.5%	7.8%	14.3%	15.8%	15.6%
MRO (Canada)	67	1,097	2,114	2,447	2,574	0.4%	5.9%	10.1%	10.4%	9.7%
NYISO	1,807	12,970	22,030	25,732	27,590	1.2%	8.3%	13.2%	14.3%	14.3%
PJM	2,567	34,305	62,939	73,352	77,746	0.5%	7.1%	12.6%	14.2%	14.6%
SERC	1,061	16,276	31,213	36,552	38,777	0.3%	4.9%	8.8%	9.8%	9.8%
SPP	821	11,871	22,426	26,382	28,035	0.4%	6.1%	11.1%	12.5%	12.7%
TVA	602	9,775	18,853	21,651	22,771	0.3%	4.6%	8.5%	9.3%	9.4%
Total EI	9,948	110,754	202,161	235,603	250,238	0.6%	6.3%	10.9%	12.2%	12.3%

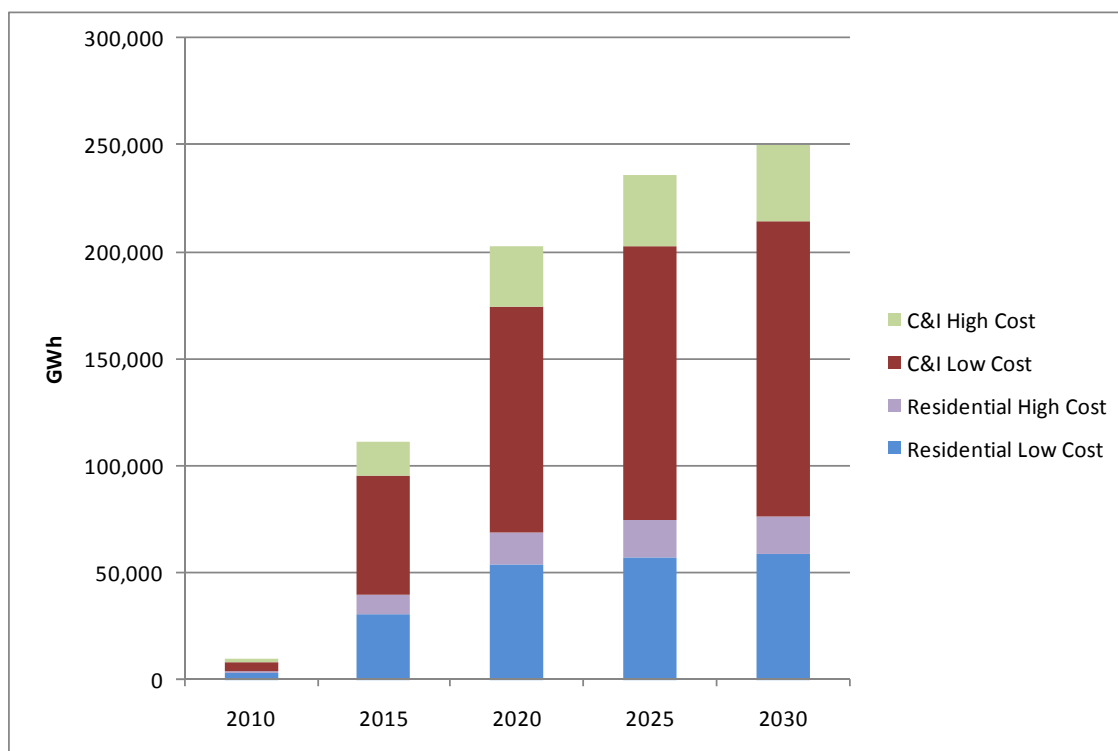
Table 3-47 Energy Efficiency – Cumulative Demand Savings Potential

RTO/ISO	Cumulative Demand Savings (MW)					Percentage of Baseline				
	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
Entergy	55	866	1,649	1,894	1,994	0.3%	4.1%	7.2%	7.5%	7.2%
IESO (Canada)	223	1,634	2,787	3,209	3,428	1.2%	7.6%	11.4%	11.5%	10.9%
ISO-NE	284	2,022	3,373	3,846	4,078	1.3%	8.7%	13.6%	14.4%	14.2%
MAPP	9	153	298	348	368	0.2%	4.0%	7.3%	8.0%	8.1%
MRO (Canada)	13	210	401	458	480	0.2%	3.2%	5.8%	6.2%	6.2%
NYISO	338	2,449	4,144	4,779	5,103	1.2%	7.9%	12.1%	12.8%	12.5%
PJM	539	7,101	12,830	14,769	15,593	0.7%	9.0%	15.2%	16.5%	16.3%
SERC	210	3,206	6,068	7,003	7,400	0.3%	4.8%	8.2%	8.6%	8.3%
SPP	164	2,333	4,337	5,033	5,328	0.4%	5.7%	9.8%	10.4%	10.1%
TVA	120	1,961	3,742	4,228	4,428	0.2%	3.5%	6.1%	6.3%	6.0%
Total EI	1,953	21,936	39,630	45,567	48,200	0.6%	6.3%	10.4%	11.0%	10.7%

Table 3-48 and Table 3-49 show the energy and demand savings potential by the four program cost blocks, respectively. These savings are graphically presented in Figure 3-23 and Figure 3-24. C&I Low Cost Programs are projected to account for the largest portion of the total savings. Residential Low Cost Programs will also contribute a significant amount of savings, while Residential and C&I High Cost Programs account for a relatively small portion of the total savings in the Eastern Interconnection.

Table 3-48 Cumulative Energy Savings by EE Program Cost (GWh)

EGEAS Block	2010	2015	2020	2025	2030
Residential Low Cost	3,040	30,889	54,030	57,241	58,584
Residential High Cost	712	8,809	14,997	16,939	17,910
Total Residential	3,752	39,698	69,027	74,180	76,494
C&I Low Cost	4,640	55,398	105,521	128,355	137,989
C&I High Cost	1,556	15,658	27,613	33,068	35,755
Total C&I	6,196	71,056	133,134	161,423	173,744
Total EE for EI	9,948	110,754	202,161	235,603	250,238

Figure 3-23 Energy Efficiency – Cumulative Energy Savings by Program Cost**Table 3-49 Cumulative Demand Savings by EE Program Cost (MW)**

EGEAS Block	2010	2015	2020	2025	2030
Residential Low Cost	716	7,601	13,430	14,253	14,596
Residential High Cost	177	2,236	3,821	4,316	4,564
Total Residential	893	9,837	17,250	18,569	19,160
C&I Low Cost	784	9,324	17,501	21,165	22,736
C&I High Cost	276	2,774	4,878	5,833	6,304
Total C&I	1,060	12,099	22,380	26,998	29,040
Total EE for EI	1,953	21,936	39,630	45,567	48,200

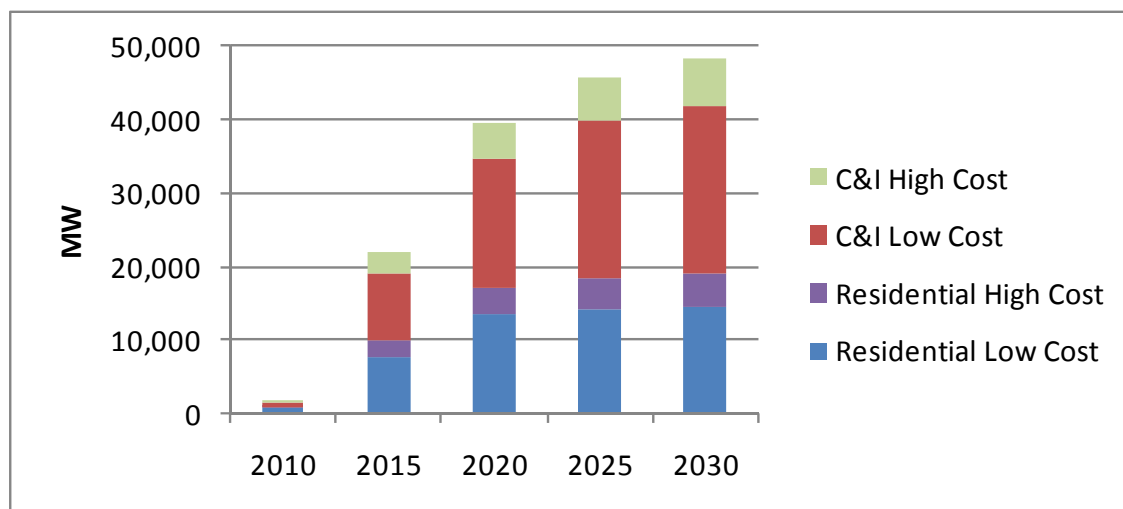
Figure 3-24 Energy Efficiency – Cumulative Demand Savings by EE Program Cost

Table 3-50 shows the estimate of the budget required to implement the energy-efficiency programs and achieve the incremental savings. During the 2010-2020 timeframe, the annual program budget requirements ramp up during the first portion of the period and then decline during the latter portion of the period. The ramping up corresponds to the expected increase in energy-efficiency program implementation and activities during the next several years. The energy-efficiency program spending will start to decline as more customers participate and the market for energy-efficiency technologies approaches projected saturation limits. Note that the dollar amounts shown are nominal dollars.

Table 3-50 Energy Efficiency – Program Budget Requirement (\$ millions)

Cost Block	2010	2015	2020	2025	2030
Residential - Low Cost Programs	\$445	\$984	\$410	\$92	\$46
Residential - High Cost Programs	\$277	\$996	\$439	\$194	\$115
Total Residential Programs	\$723	\$1,980	\$850	\$286	\$161
C&I - Low Cost Programs	\$477	\$1,537	\$1,072	\$503	\$255
C&I - High Cost Programs	\$577	\$1,361	\$817	\$446	\$274
Total C&I Programs	\$1,053	\$2,898	\$1,889	\$949	\$529
Total Eastern Interconnection	\$1,776	\$4,878	\$2,739	\$1,235	\$691

Table 3-51 shows the average cost per kWh saved for the energy-efficiency programs. The values show an increasing trend over time since the “low-hanging fruit” is captured in the early portion of the forecast horizon and utilities are left with increasingly difficult segments of the market to achieve savings during the latter portion of the forecast.

Table 3-51 Energy Efficiency – Average Cost per kWh Saved

Cost Block	2010	2015	2020	2025	2030
Residential - Low Cost Programs	\$0.15	\$0.15	\$0.18	\$0.21	\$0.24
Residential - High Cost Programs	\$0.39	\$0.52	\$0.58	\$0.68	\$0.78
Total Residential Programs	\$0.19	\$0.24	\$0.28	\$0.40	\$0.48
C&I - Low Cost Programs	\$0.10	\$0.12	\$0.14	\$0.16	\$0.19
C&I - High Cost Programs	\$0.37	\$0.41	\$0.48	\$0.56	\$0.67
Total C&I Programs	\$0.17	\$0.18	\$0.20	\$0.24	\$0.30
Total Eastern Interconnection	\$0.18	\$0.20	\$0.22	\$0.27	\$0.33

3.3.2 Energy Efficiency Results by Eastern Interconnection RTO/ISO Planning Area

The following sections present more detailed results for each RTO/ISO planning area.

3.3.2.1 Entergy

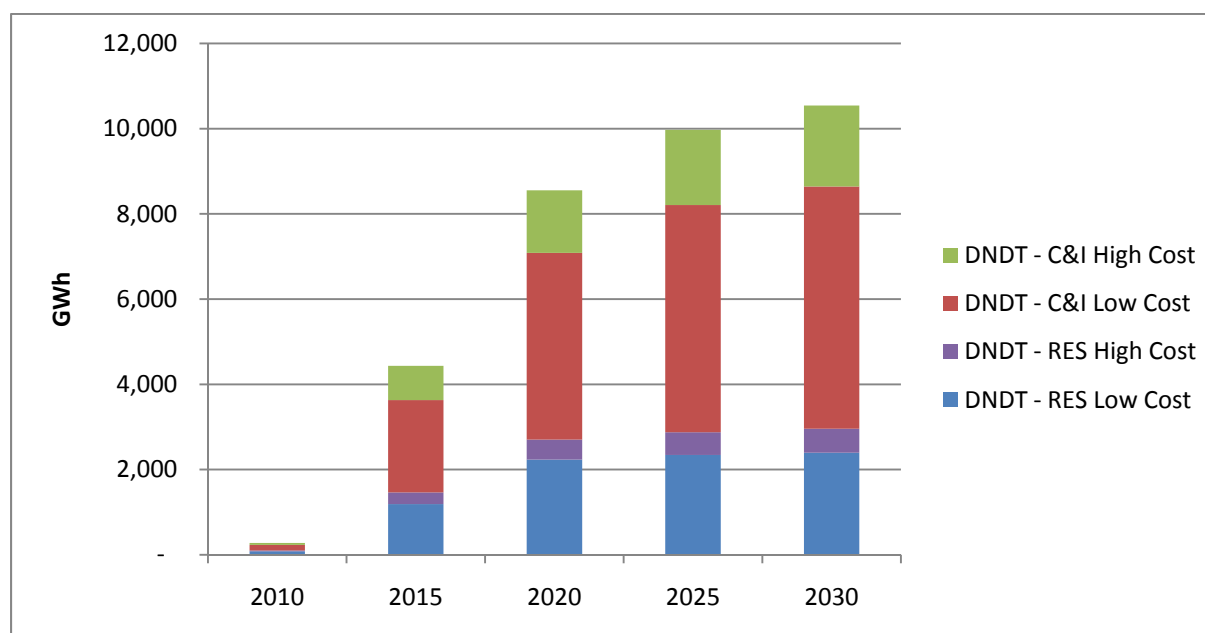
The Entergy planning area covers the southern states of Arkansas, Louisiana, Mississippi, Tennessee, and Texas. With the exception of Texas, all of these states were mapped to the Midwest ISO East Region due to the lack of current state legislation that sets energy savings goals and general lack of existing program implementation experience in the region.²⁰ Texas was mapped to the Midwest ISO Central Region due to the existence of state legislation requiring utilities to offset load growth through energy efficiency. In addition, the savings per participant figures for Louisiana, Mississippi, and Texas were adjusted to reflect the warmer climate (and thus higher cooling energy consumption) in these states relative to the Midwest ISO regions.

The following figures and tables show that cumulative energy savings will reach over 10,500 GWh (8.5% of baseline) by 2030, and cumulative demand savings will reach almost 2,000 MW (7.2% of baseline) by 2030. Entergy ranks at number seven for both energy and demand savings in the comparison of savings potential within the ten RTO/ISO planning areas. This result is consistent with the fact that Entergy is the seventh-most populous region amongst the ten RTO/ISO planning areas in terms of number of customers.

Table 3-52 Entergy – Cumulative Energy Savings by EE Program Cost (GWh)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	84	1,190	2,236	2,343	2,396
DNDT - RES High Cost	17	273	467	532	563
Total RES	101	1,463	2,703	2,875	2,959
DNDT - C&I Low Cost	130	2,167	4,382	5,332	5,684
DNDT - C&I High Cost	49	806	1,468	1,764	1,899
Total C&I	178	2,973	5,850	7,096	7,584
Total Entergy	280	4,436	8,553	9,971	10,543

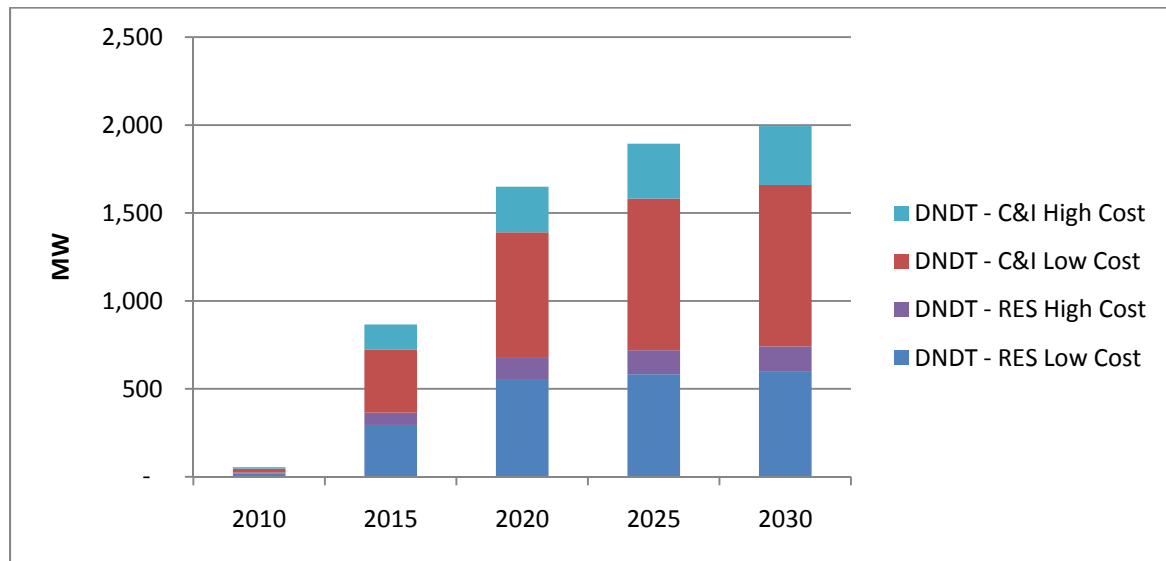
Figure 3-25 Entergy – Cumulative Energy Savings by EE Program Cost



²⁰ Within the context of the approach used for the Eastern Interconnection, the Midwest ISO East Region is used to represent regions that generally do not have significant experience with energy efficiency program implementation and/or are not required to achieve specific energy-efficiency goals by state legislation.

Table 3-53 Entergy – Cumulative Peak Demand Savings by Program Cost (MW)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	20	295	556	584	597
DNDT - RES High Cost	4	70	120	136	144
Total RES	25	365	676	720	741
DNDT - C&I Low Cost	22	359	714	863	918
DNDT - C&I High Cost	9	142	259	311	335
Total C&I	30	501	973	1,174	1,253
Total Entergy	55	866	1,649	1,894	1,994

Figure 3-26 Entergy – Cumulative Peak Demand Savings**Table 3-54 Entergy – Program Budget Requirement (\$ millions)**

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$8	\$30	\$13	\$3	\$1
DNDT - RES High Cost	\$13	\$61	\$26	\$12	\$7
Total RES	\$22	\$92	\$39	\$14	\$8
DNDT - C&I Low Cost	\$13	\$62	\$45	\$19	\$8
DNDT - C&I High Cost	\$15	\$65	\$37	\$20	\$11
Total C&I	\$28	\$128	\$82	\$39	\$19
Total Entergy	\$50	\$219	\$121	\$53	\$27

Table 3-55 Entergy – Average Cost per kWh Saved

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$0.10	\$0.11	\$0.13	\$0.16	\$0.18
DNDT - RES High Cost	\$0.79	\$0.97	\$1.07	\$1.24	\$1.40
Total RES (weighted average)	\$0.22	\$0.27	\$0.31	\$0.57	\$0.63
DNDT - C&I Low Cost	\$0.10	\$0.12	\$0.13	\$0.16	\$0.18
DNDT - C&I High Cost	\$0.30	\$0.34	\$0.40	\$0.47	\$0.55
Total C&I (weighted average)	\$0.16	\$0.17	\$0.19	\$0.24	\$0.29
Total Entergy (weighted average)	\$0.18	\$0.21	\$0.22	\$0.28	\$0.35

3.3.2.2 IESO

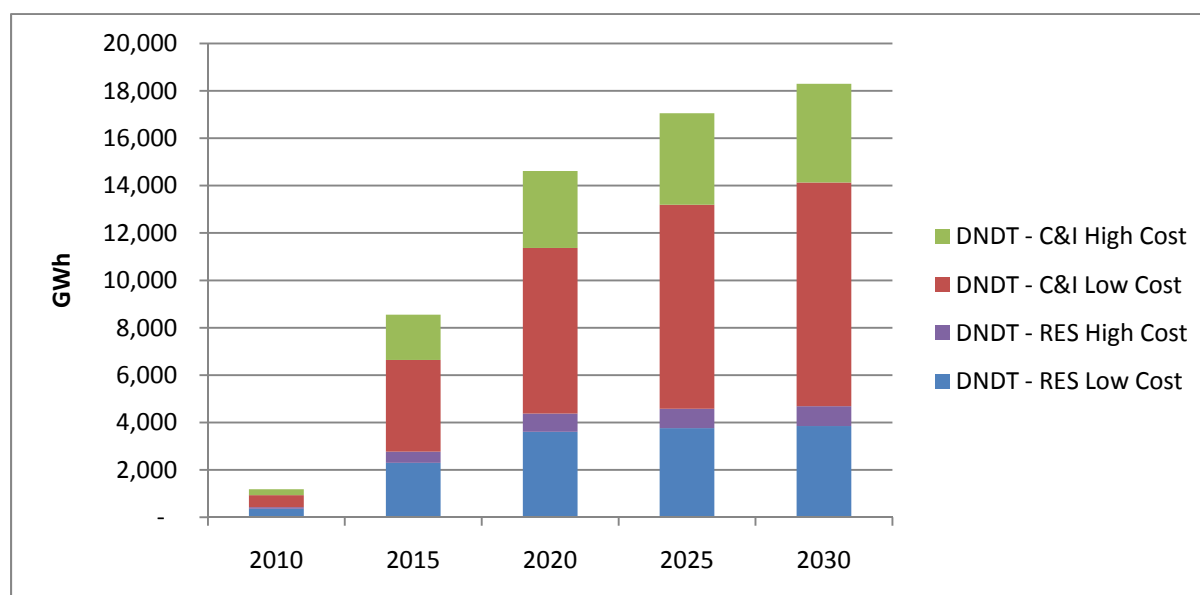
The IESO planning area covers the Ontario province of Canada. The entire IESO was mapped to the Midwest ISO West Region.²¹ In addition, the savings per participant figures were adjusted to reflect the colder climate in Ontario relative to the Midwest ISO regions.

The following figures and tables show that cumulative energy savings will reach over 18,300 GWh (over 11% of baseline) by 2030, and cumulative demand savings will reach over 3,400 MW (almost 11% of baseline) by 2030. IESO ranks at number six for energy savings and number five for demand savings in the comparison of savings potential within the ten RTO/ISO planning areas. This result is consistent with the fact that IESO is the sixth-most populous region amongst the ten RTO/ISO planning areas in terms of number of customers.

Table 3-56 IESO – Cumulative Energy Savings by EE Program Cost (GWh)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	358	2,294	3,605	3,765	3,852
DNDT - RES High Cost	69	477	776	817	838
Total RES	426	2,772	4,380	4,583	4,690
DNDT - C&I Low Cost	505	3,867	6,985	8,606	9,438
DNDT - C&I High Cost	252	1,917	3,250	3,865	4,173
Total C&I	756	5,783	10,234	12,471	13,611
Total IESO (Ont-Canada)	1,183	8,555	14,615	17,054	18,301

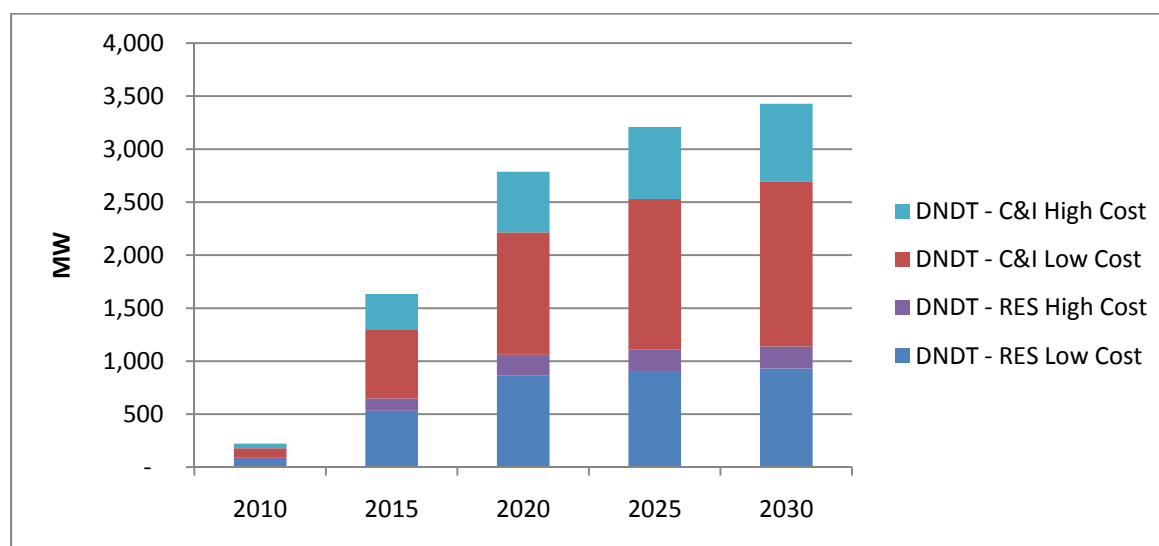
Figure 3-27 IESO – Cumulative Energy Savings as by EE Program Cost



²¹ Within the context of the approach used for the Eastern Interconnection, the Midwest ISO West Region is used to represent regions that have the most experience in energy-efficiency program implementation and achieving program impacts. Energy-efficiency programs have been established and in place for a number of years.

Table 3-57 IESO – Cumulative Demand Savings by EE Program Cost (MW)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	78	532	866	908	930
DNDT - RES High Cost	16	117	193	204	209
Total RES	94	648	1,060	1,112	1,139
DNDT - C&I Low Cost	84	646	1,155	1,419	1,558
DNDT - C&I High Cost	45	340	572	678	732
Total C&I	129	986	1,728	2,097	2,289
Total IESO (Ont-Canada)	223	1,634	2,787	3,209	3,428

Figure 3-28 IESO – Cumulative Demand Savings by EE Program Cost**Table 3-58 IESO – Program Budget Requirement (\$ millions)**

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$62	\$74	\$31	\$7	\$4
DNDT - RES High Cost	\$19	\$26	\$11	\$3	\$2
Total RES	\$81	\$100	\$42	\$9	\$6
DNDT - C&I Low Cost	\$48	\$82	\$64	\$35	\$22
DNDT - C&I High Cost	\$95	\$160	\$98	\$53	\$33
Total C&I	\$143	\$243	\$162	\$88	\$55
Total IESO (Ont-Canada)	\$224	\$343	\$204	\$97	\$61

Table 3-59 IESO – Average Cost per kWh Saved

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$0.17	\$0.20	\$0.23	\$0.27	\$0.31
DNDT - RES High Cost	\$0.27	\$0.31	\$0.36	\$0.42	\$0.49
Total RES (weighted average)	\$0.19	\$0.22	\$0.26	\$0.30	\$0.35
DNDT - C&I Low Cost	\$0.09	\$0.11	\$0.13	\$0.15	\$0.17
DNDT - C&I High Cost	\$0.38	\$0.44	\$0.51	\$0.59	\$0.68
Total C&I (weighted average)	\$0.19	\$0.22	\$0.23	\$0.27	\$0.31
Total IESO (Ont-Canada) (weighted average)	\$0.19	\$0.22	\$0.24	\$0.27	\$0.31

3.3.2.3 ISO-NE

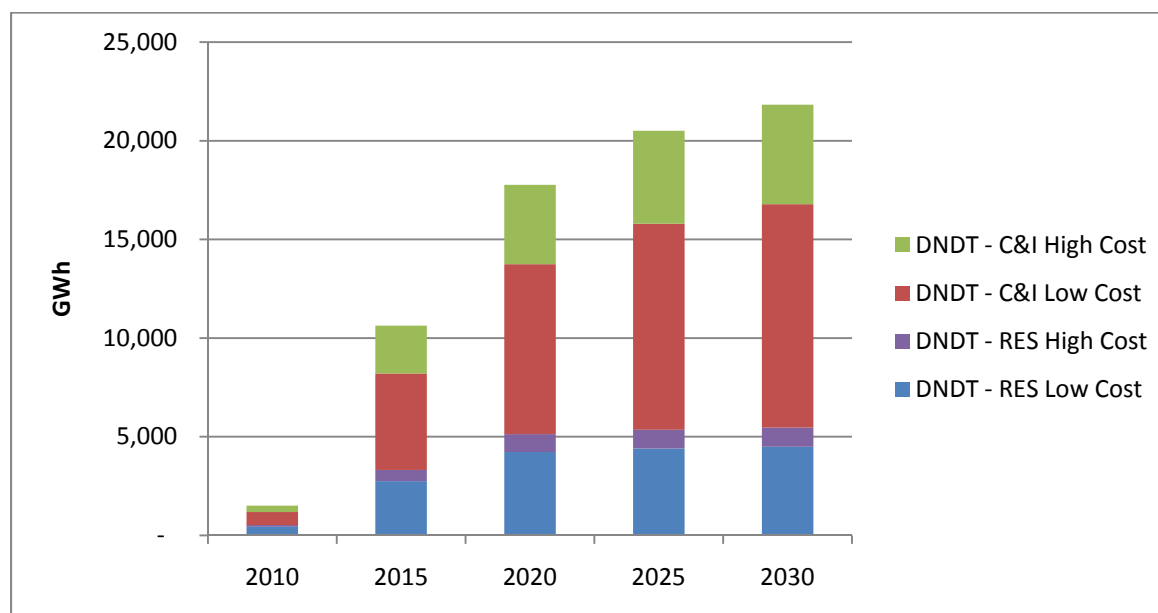
The ISO-NE planning area covers the New England states of Connecticut, Massachusetts, Maine, New Hampshire, Rhode Island, and Vermont. All of these states were mapped to the Midwest ISO West Region because of the existence of state legislation that sets energy savings goals and program implementation experience in the region.²² In addition, the savings per participant figures were adjusted to reflect the colder climate in these states relative to the Midwest ISO regions.

The following figures and tables show that cumulative energy savings will reach over 21,800 GWh (almost 16% of baseline) by 2030, and cumulative demand savings will reach over 4,000 MW (over 14% of baseline) by 2030. ISO-NE ranks at number five for energy savings and four for demand savings in the comparison of savings potential within the ten RTO/ISO planning areas. This result is consistent with the fact that ISO-NE is the fourth-most populous region amongst the ten RTO/ISO planning areas in terms of number of customers.

Table 3-60 ISO-NE – Cumulative Energy Savings by EE Program Cost (GWh)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	440	2,745	4,228	4,401	4,488
DNDT - RES High Cost	84	570	908	953	974
Total RES	524	3,315	5,137	5,354	5,462
DNDT - C&I Low Cost	658	4,890	8,611	10,441	11,327
DNDT - C&I High Cost	329	2,425	4,017	4,711	5,040
Total C&I	987	7,315	12,629	15,152	16,367
Total ISO-NE	1,511	10,630	17,765	20,506	21,829

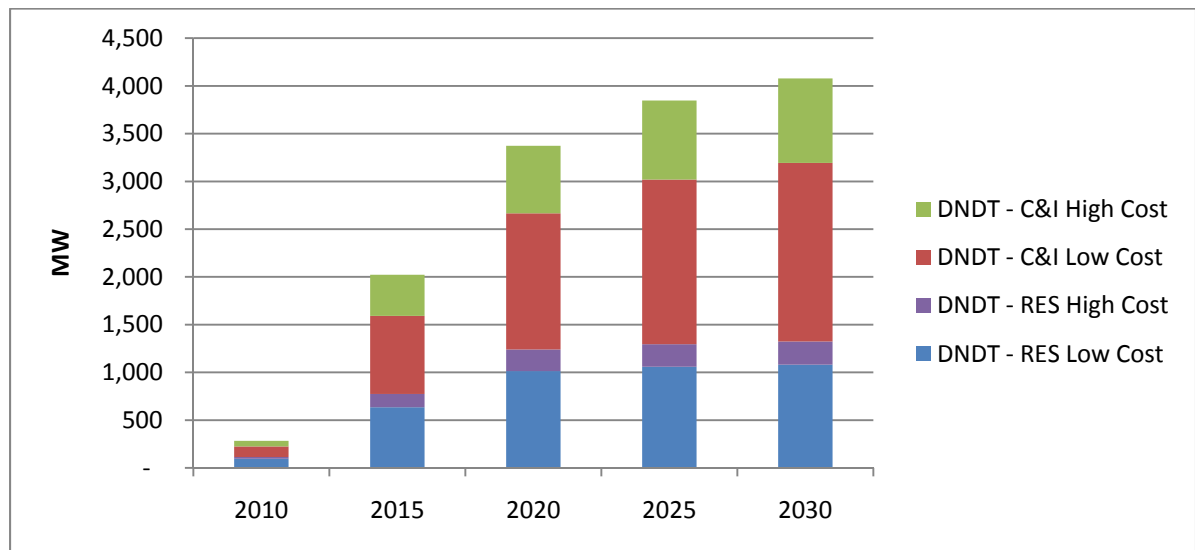
Figure 3-29 ISO-NE – Cumulative Energy Savings by EE Program Cost (MW)



²² Within the context of the approach used for the Eastern Interconnection, the Midwest ISO West Region is used to represent regions that have the most experience in energy-efficiency program implementation and achieving program impacts. Energy-efficiency programs have been established and in place for a number of years.

Table 3-61 ISO-NE – Cumulative Demand Savings by EE Program Cost (MW)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	96	636	1,015	1,059	1,081
DNDT - RES High Cost	20	139	226	237	243
Total RES	115	775	1,240	1,296	1,324
DNDT - C&I Low Cost	110	818	1,425	1,723	1,870
DNDT - C&I High Cost	58	429	708	827	884
Total C&I	168	1,247	2,133	2,550	2,754
Total ISO-NE	284	2,022	3,373	3,846	4,078

Figure 3-30 ISO-NE – Cumulative Demand Savings by EE Program Cost**Table 3-62 ISO-NE – Program Budget Requirement (\$ millions)**

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$76	\$87	\$34	\$7	\$4
DNDT - RES High Cost	\$23	\$31	\$12	\$3	\$2
Total RES	\$99	\$117	\$47	\$10	\$6
DNDT - C&I Low Cost	\$62	\$101	\$74	\$39	\$23
DNDT - C&I High Cost	\$125	\$198	\$114	\$58	\$34
Total C&I	\$187	\$299	\$188	\$97	\$57
Total ISO-NE	\$286	\$416	\$234	\$106	\$63

Table 3-63 ISO-NE – Average Cost per kWh Saved

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$0.17	\$0.20	\$0.23	\$0.27	\$0.31
DNDT - RES High Cost	\$0.27	\$0.31	\$0.36	\$0.42	\$0.49
Total RES (weighted average)	\$0.19	\$0.22	\$0.26	\$0.30	\$0.35
DNDT - C&I Low Cost	\$0.09	\$0.11	\$0.13	\$0.15	\$0.17
DNDT - C&I High Cost	\$0.38	\$0.44	\$0.51	\$0.59	\$0.68
Total C&I (weighted average)	\$0.19	\$0.22	\$0.23	\$0.27	\$0.31
Total ISO-NE (weighted average)	\$0.19	\$0.22	\$0.24	\$0.27	\$0.31

3.3.2.4 MAPP

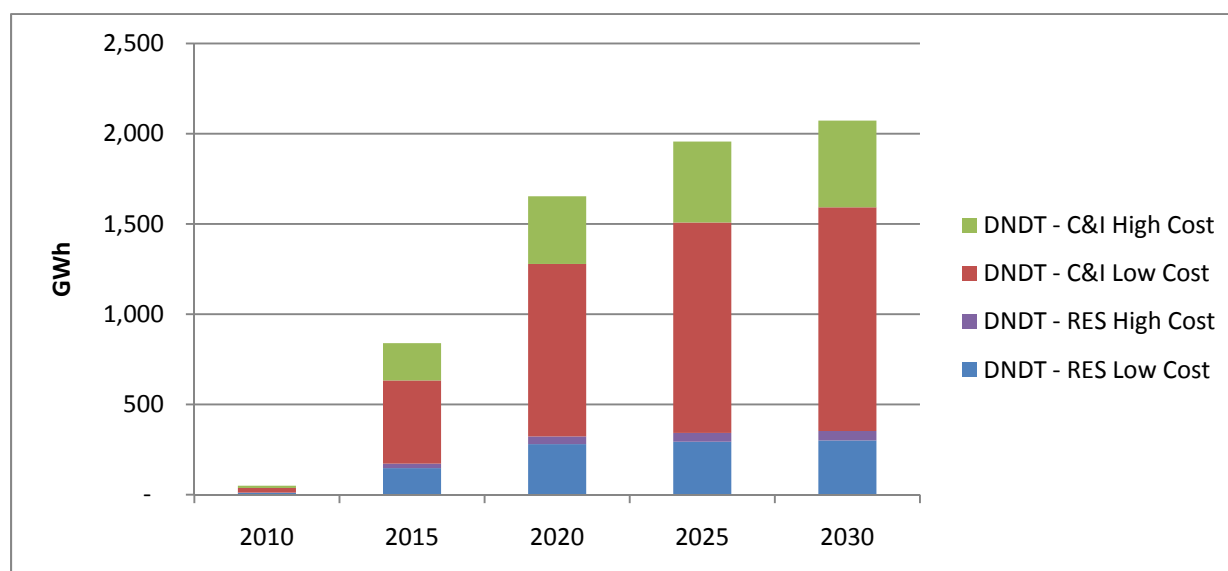
The MAPP planning area covers the Midwest states of North Dakota and South Dakota. These two states were mapped to the Midwest ISO East Region due to the lack of current state legislation that sets energy savings goals and general lack of existing program implementation experience amongst utilities in the states.²³

The following figures and tables show that cumulative energy savings will reach over 2,000 GWh (almost 16% of baseline) by 2030, and cumulative demand savings will reach approximately 368 MW (over 6% of baseline) by 2030. MAPP is the region with the least savings potential when compared to the other nine RTO/ISO planning areas. This result is consistent with the fact that MAPP has the fewest customers amongst the ten RTO/ISO planning areas.

Table 3-64 MAPP – Cumulative Energy Savings by EE Program Cost (GWh)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	10	147	281	293	301
DNDT - RES High Cost	1	25	42	49	52
Total RES	11	172	323	342	352
DNDT - C&I Low Cost	26	461	956	1,166	1,239
DNDT - C&I High Cost	12	207	375	448	481
Total C&I	38	668	1,330	1,614	1,721
Total MAPP	49	840	1,653	1,956	2,073

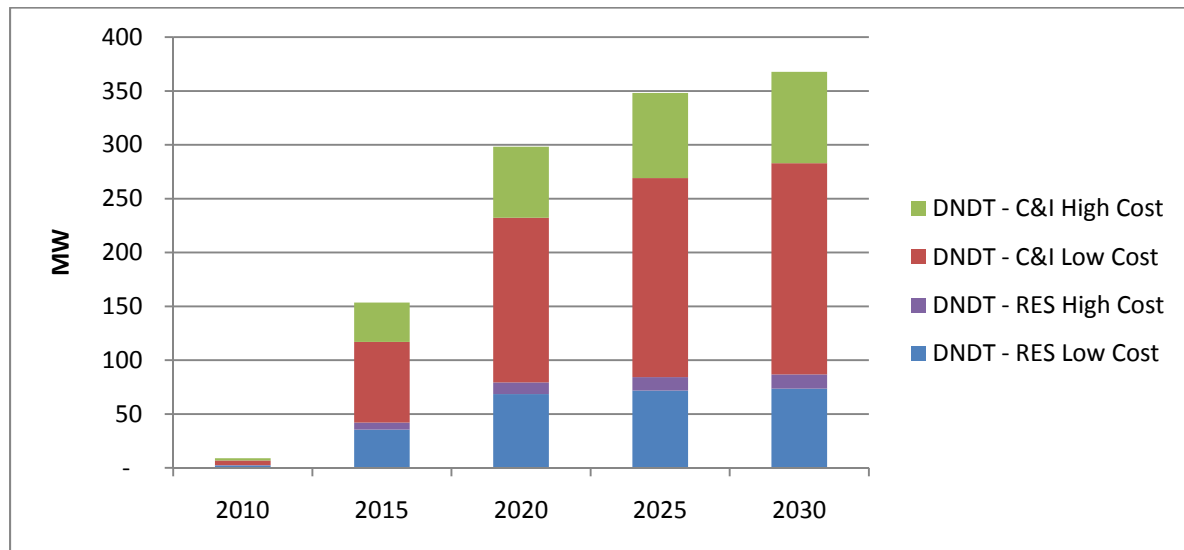
Figure 3-31 MAPP – Cumulative Energy Savings by EE Program Cost



²³ Within the context of the approach used for the Eastern Interconnection, the Midwest ISO East Region is used to represent regions that generally do not have significant experience with energy efficiency program implementation and/or are not required to achieve specific energy-efficiency goals by state legislation.

Table 3-65 MAPP – Cumulative Demand Savings by EE Program Cost (MW)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	2	36	69	72	74
DNDT - RES High Cost	0	6	11	13	13
Total RES	3	42	79	84	87
DNDT - C&I Low Cost	4	75	153	185	196
DNDT - C&I High Cost	2	36	66	79	85
Total C&I	6	111	219	264	281
Total MAPP	9	153	298	348	368

Figure 3-32 MAPP – Cumulative Demand Savings by EE Program Cost**Table 3-66 MAPP – Program Budget Requirement (\$ millions)**

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$1	\$3	\$1	\$0	\$0
DNDT - RES High Cost	\$2	\$9	\$4	\$2	\$1
Total RES	\$3	\$12	\$5	\$2	\$1
DNDT - C&I Low Cost	\$2	\$13	\$10	\$4	\$2
DNDT - C&I High Cost	\$3	\$16	\$9	\$5	\$2
Total C&I	\$6	\$29	\$19	\$9	\$4
Total MAPP	\$9	\$41	\$24	\$11	\$5

Table 3-67 MAPP – Average Cost per kWh Saved

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$0.08	\$0.09	\$0.10	\$0.12	\$0.14
DNDT - RES High Cost	\$1.31	\$1.52	\$1.76	\$2.04	\$2.37
Total RES (weighted average)	\$0.23	\$0.30	\$0.34	\$0.71	\$0.76
DNDT - C&I Low Cost	\$0.10	\$0.11	\$0.13	\$0.15	\$0.17
DNDT - C&I High Cost	\$0.29	\$0.33	\$0.38	\$0.44	\$0.51
Total C&I (weighted average)	\$0.16	\$0.18	\$0.19	\$0.23	\$0.29
Total MAPP (weighted average)	\$0.17	\$0.20	\$0.21	\$0.27	\$0.34

3.3.2.5 MRO (Canada)

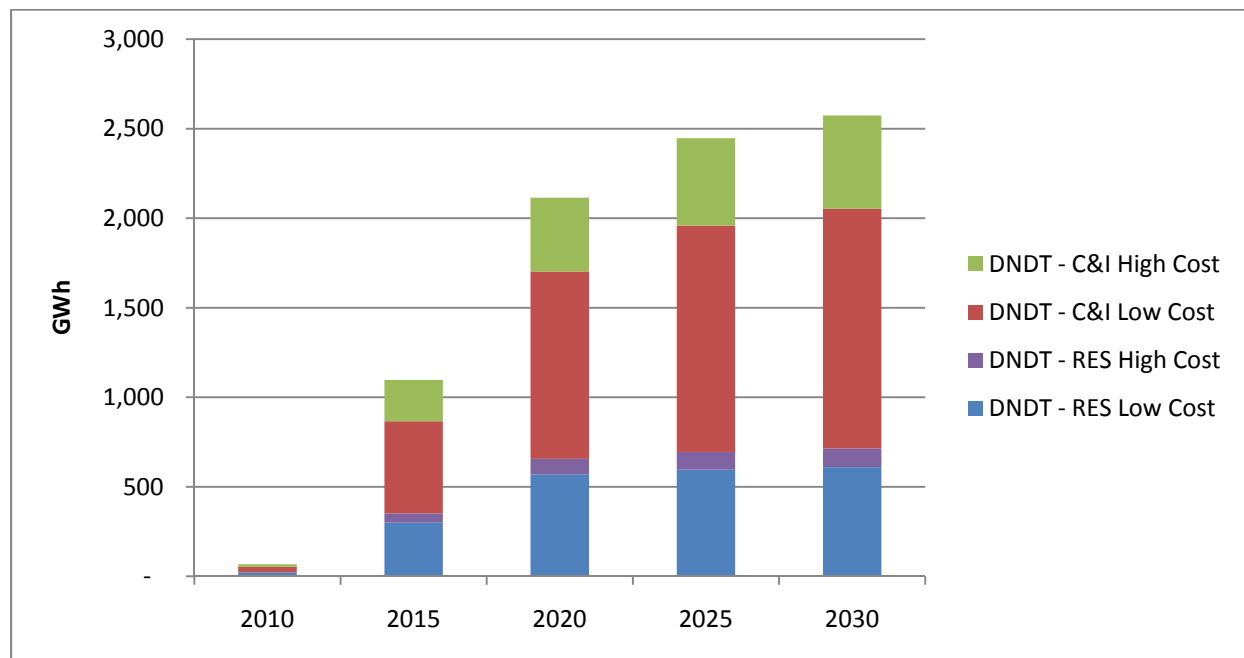
The MRO planning area covers the province of Saskatchewan, Canada. The entire MRO was mapped to the Midwest ISO East Region.²⁴

The following figures and tables show that cumulative energy savings will reach over 2,500 GWh by 2030, and cumulative demand savings will reach 480 MW by 2030. MRO ranks at number nine for both energy and demand savings in the comparison of savings potential within the ten RTO/ISO planning areas. This result is consistent with the fact that MRO is the ninth-most populous region amongst the ten RTO/ISO planning areas in terms of number of customers.

Table 3-68 MRO - Canada – Cumulative Energy Savings by EE Program Cost (GWh)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	20	300	570	595	610
DNDT - RES High Cost	3	51	86	99	105
Total RES	23	351	656	694	715
DNDT - C&I Low Cost	30	515	1,047	1,264	1,339
DNDT - C&I High Cost	14	231	412	488	521
Total C&I	44	746	1,458	1,753	1,859
Total MRO (SK-Canada)	67	1,097	2,114	2,447	2,574

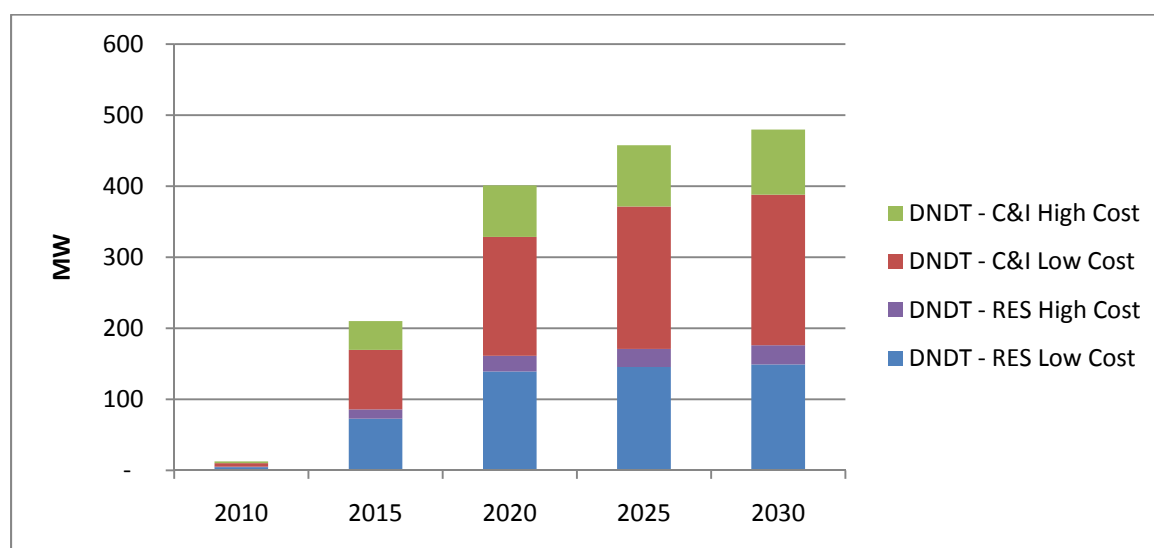
Figure 3-33 MRO - Canada – Cumulative Energy Savings by EE Program Cost



²⁴ Within the context of the approach used for the Eastern Interconnection, the Midwest ISO East Region is used to represent regions that generally do not have significant experience with energy efficiency program implementation and/or are not required to achieve specific energy-efficiency goals by state legislation.

Table 3-69 MRO - Canada – Cumulative Demand Savings by EE Program Cost (MW)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	5	73	139	146	149
DNDT - RES High Cost	1	13	22	25	27
Total RES	5	86	161	171	176
DNDT - C&I Low Cost	5	84	167	201	212
DNDT - C&I High Cost	2	41	73	86	92
Total C&I	7	124	240	287	304
Total MRO (SK-Canada)	13	210	401	458	480

Figure 3-34 MRO - Canada – Cumulative Demand Savings by EE Program Cost**Table 3-70 MRO - Canada – Program Budget Requirement (\$ millions)**

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$2	\$6	\$3	\$0	\$0
DNDT - RES High Cost	\$4	\$18	\$8	\$4	\$2
Total RES	\$5	\$24	\$10	\$4	\$2
DNDT - C&I Low Cost	\$3	\$14	\$10	\$4	\$2
DNDT - C&I High Cost	\$4	\$18	\$10	\$5	\$2
Total C&I	\$7	\$32	\$20	\$9	\$4
Total MRO (SK-Canada)	\$12	\$56	\$30	\$13	\$6

Table 3-71 MRO - Canada – Average Cost per kWh Saved

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$0.08	\$0.09	\$0.10	\$0.12	\$0.14
DNDT - RES High Cost	\$1.31	\$1.52	\$1.76	\$2.04	\$2.37
Total RES (weighted average)	\$0.23	\$0.30	\$0.34	\$0.71	\$0.76
DNDT - C&I Low Cost	\$0.10	\$0.11	\$0.13	\$0.15	\$0.17
DNDT - C&I High Cost	\$0.29	\$0.33	\$0.38	\$0.44	\$0.51
Total C&I (weighted average)	\$0.16	\$0.18	\$0.19	\$0.23	\$0.29
Total MRO (SK-Canada) (weighted average)	\$0.18	\$0.21	\$0.22	\$0.30	\$0.38

3.3.2.6 NYISO

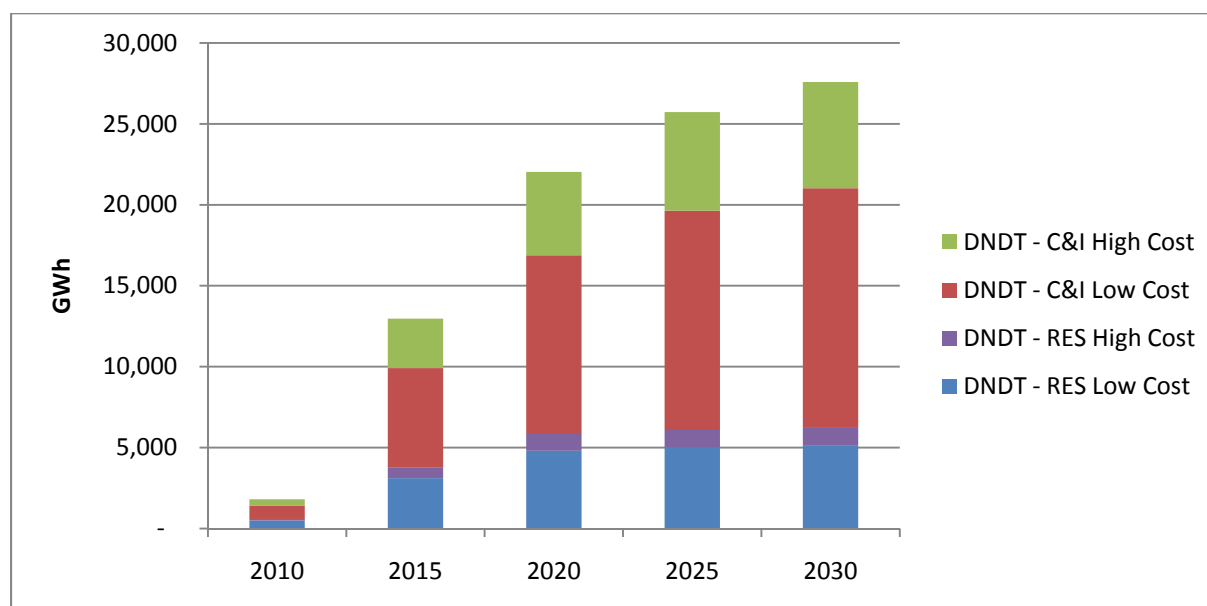
The NYISO planning area covers the state of New York. NYISO was mapped to the Midwest ISO West Region because of the existence of state legislation that sets energy savings goals and program implementation experience in New York State.²⁵ In addition, the savings per participant figures were adjusted to reflect the colder climate in New York State relative to the Midwest ISO regions.

The following figures and tables show that cumulative energy savings will reach over 27,500 GWh (over 14% of baseline) by 2030, and cumulative demand savings will reach over 5,100 MW (over 12% of baseline) by 2030. NYISO ranks at number three for both energy savings and demand savings in the comparison of savings potential within the ten RTO/ISO planning areas. This result is consistent with the fact that NYISO is the third-most populous region amongst the ten RTO/ISO planning areas in terms of number of customers.

Table 3-72 NYISO – Cumulative Energy Savings by EE Program Cost (GWh)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	497	3,111	4,806	5,005	5,106
DNDT - RES High Cost	95	647	1,033	1,084	1,109
Total RES	592	3,758	5,839	6,089	6,215
DNDT - C&I Low Cost	811	6,159	11,047	13,550	14,814
DNDT - C&I High Cost	405	3,053	5,143	6,093	6,561
Total C&I	1,215	9,212	16,191	19,643	21,375
Total NYISO (Eastern Int.)	1,807	12,970	22,030	25,732	27,590

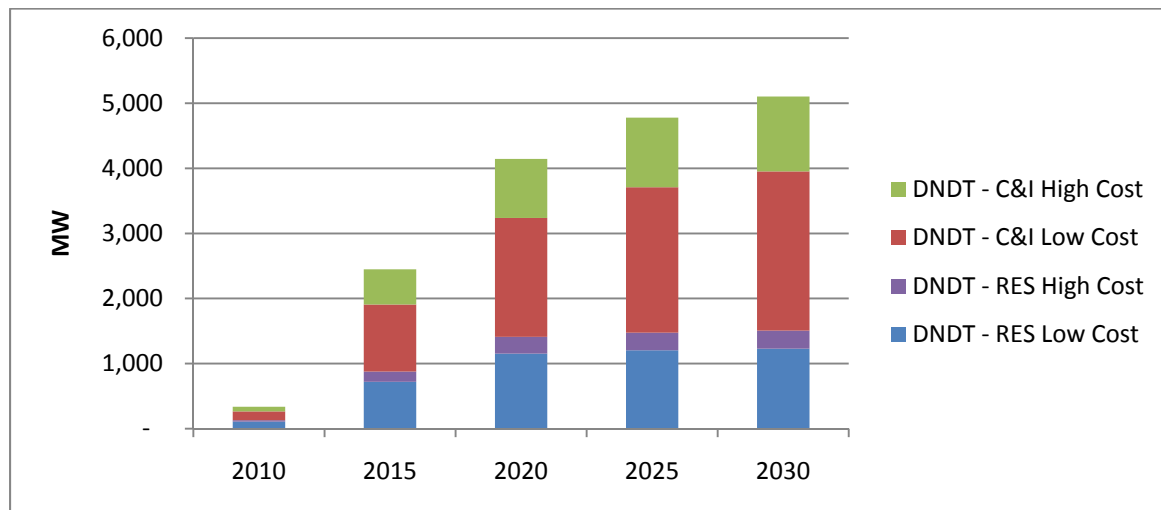
Figure 3-35 NYISO – Cumulative Energy Savings by EE Program Cost



²⁵ Within the context of the approach used for the Eastern Interconnection, the Midwest ISO West Region is used to represent regions that have the most experience in energy-efficiency program implementation and achieving program impacts. Energy-efficiency programs have been established and in place for a number of years.

Table 3-73 NYISO – Cumulative Demand Savings by EE Program Cost (MW)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	108	721	1,154	1,204	1,230
DNDT - RES High Cost	22	158	257	270	276
Total RES	130	878	1,410	1,474	1,507
DNDT - C&I Low Cost	136	1,030	1,828	2,235	2,445
DNDT - C&I High Cost	72	541	906	1,070	1,151
Total C&I	207	1,570	2,733	3,304	3,596
Total NYISO (Eastern Int.)	338	2,449	4,144	4,779	5,103

Figure 3-36 NYISO – Cumulative Demand Savings by EE Program Cost**Table 3-74 NYISO – Program Budget Requirement (\$ millions)**

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$86	\$98	\$39	\$8	\$5
DNDT - RES High Cost	\$26	\$35	\$14	\$3	\$2
Total RES	\$112	\$133	\$53	\$11	\$7
DNDT - C&I Low Cost	\$77	\$130	\$99	\$54	\$34
DNDT - C&I High Cost	\$153	\$254	\$152	\$81	\$49
Total C&I	\$230	\$384	\$251	\$135	\$83
Total NYISO	\$342	\$517	\$305	\$146	\$89

Table 3-75 NYISO – Average Cost per kWh Saved

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$0.17	\$0.20	\$0.23	\$0.27	\$0.31
DNDT - RES High Cost	\$0.27	\$0.31	\$0.36	\$0.42	\$0.49
Total RES (weighted average)	\$0.19	\$0.22	\$0.26	\$0.30	\$0.35
DNDT - C&I Low Cost	\$0.09	\$0.11	\$0.13	\$0.15	\$0.17
DNDT - C&I High Cost	\$0.38	\$0.44	\$0.51	\$0.59	\$0.68
Total C&I (weighted average)	\$0.19	\$0.22	\$0.23	\$0.27	\$0.31
Total NYISO (weighted average)	\$0.19	\$0.22	\$0.24	\$0.27	\$0.31

3.3.2.7 PJM

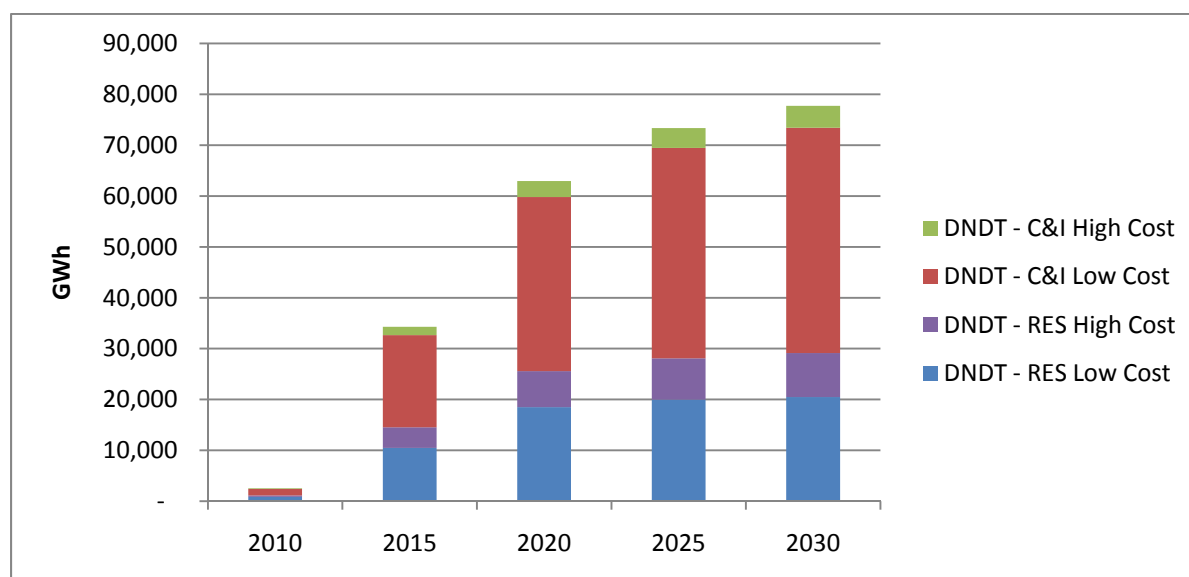
From a geographic stand point, the PJM planning area covers the largest area. PJM's territory spans the following states: Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia, and the District of Columbia. With the exception of Kentucky and West Virginia, all of these states were mapped to the Midwest ISO Central Region due to the existence of current state legislation that sets energy savings goals in combination with a low level of program implementation experience in the region.²⁶ Kentucky and West Virginia do not currently have state legislation that requires utilities to meet energy-efficiency goals, and thus were mapped to the Midwest ISO East Region.²⁷

The following figures and tables show that cumulative energy savings will reach over 77,700 GWh (approximately 15% of baseline) by 2030, and cumulative demand savings will reach almost 16,000 MW (over 16% of baseline) by 2030. PJM accounts for the largest amount of energy and demand savings within the ten RTO/ISO planning areas. This result is consistent with the fact that PJM is the most populous region amongst the ten RTO/ISO planning areas in terms of number of customers.

Table 3-76 PJM – Cumulative Energy Savings by EE Program Cost (GWh)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	867	10,472	18,515	19,986	20,498
DNDT - RES High Cost	274	4,076	7,060	8,103	8,634
Total RES	1,141	14,548	25,575	28,089	29,132
DNDT - C&I Low Cost	1,271	18,093	34,217	41,378	44,307
DNDT - C&I High Cost	155	1,664	3,146	3,885	4,307
Total C&I	1,426	19,756	37,364	45,263	48,614
Total PJM (Eastern Int.)	2,567	34,305	62,939	73,352	77,746

Figure 3-37 PJM – Cumulative Energy Savings by EE Program Cost

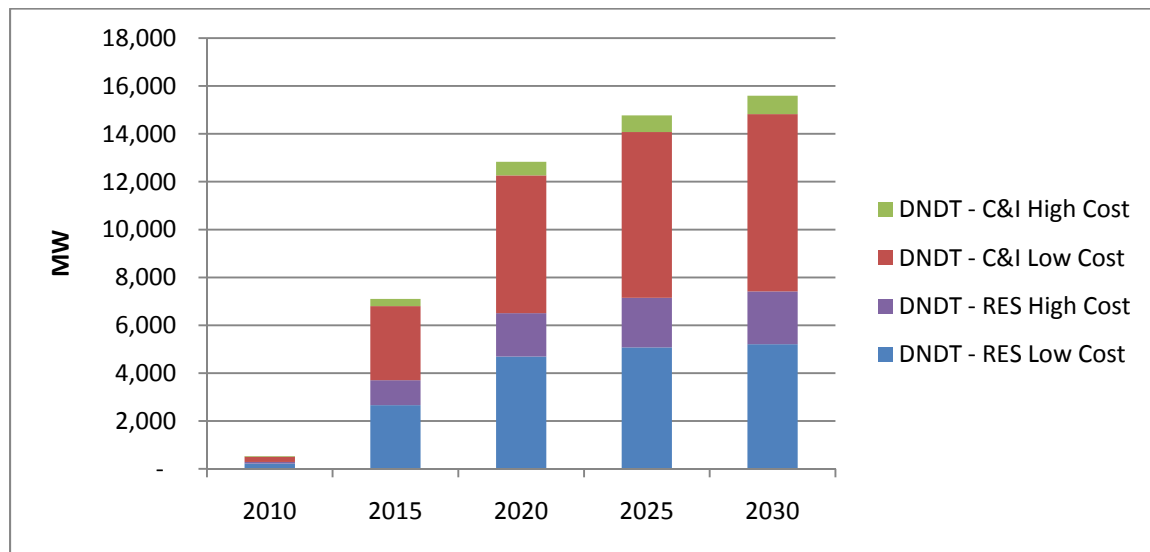


²⁶ Within the context of the approach used for the Eastern Interconnection, the Midwest ISO Central Region is used to represent regions that are relatively new to energy-efficiency program implementation but utilities in these regions are planning and/or are mandated to aggressively pursue energy efficiency in the future.

²⁷ Within the context of the approach used for the Eastern Interconnection, the Midwest ISO East Region is used to represent regions that generally do not have significant experience with energy efficiency program implementation and/or are not required to achieve specific energy-efficiency goals by state legislation.

Table 3-77 PJM – Cumulative Demand Savings by EE Program Cost (MW)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	222	2,665	4,697	5,075	5,207
DNDT - RES High Cost	70	1,044	1,807	2,073	2,208
Total RES	292	3,709	6,505	7,149	7,415
DNDT - C&I Low Cost	219	3,094	5,762	6,926	7,409
DNDT - C&I High Cost	28	298	563	694	769
Total C&I	247	3,393	6,325	7,620	8,177
Total PJM (Eastern Int.)	539	7,101	12,830	14,769	15,593

Figure 3-38 PJM – Cumulative Demand Savings by EE Program Cost**Table 3-78 PJM – Program Budget Requirement (\$ millions)**

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$127	\$393	\$164	\$41	\$18
DNDT - RES High Cost	\$79	\$308	\$147	\$69	\$42
Total RES	\$206	\$701	\$311	\$111	\$60
DNDT - C&I Low Cost	\$144	\$564	\$368	\$170	\$83
DNDT - C&I High Cost	\$70	\$194	\$131	\$80	\$57
Total C&I	\$215	\$758	\$499	\$250	\$140
Total PJM	\$421	\$1,459	\$810	\$360	\$200

Table 3-79 PJM – Average Cost per kWh Saved

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$0.15	\$0.17	\$0.20	\$0.23	\$0.26
DNDT - RES High Cost	\$0.29	\$0.34	\$0.39	\$0.45	\$0.52
Total RES (weighted average)	\$0.18	\$0.22	\$0.26	\$0.33	\$0.40
DNDT - C&I Low Cost	\$0.11	\$0.13	\$0.15	\$0.18	\$0.20
DNDT - C&I High Cost	\$0.45	\$0.52	\$0.60	\$0.70	\$0.82
Total C&I (weighted average)	\$0.15	\$0.16	\$0.19	\$0.23	\$0.30
Total PJM (weighted average)	\$0.16	\$0.18	\$0.21	\$0.26	\$0.32

3.3.2.8 SERC

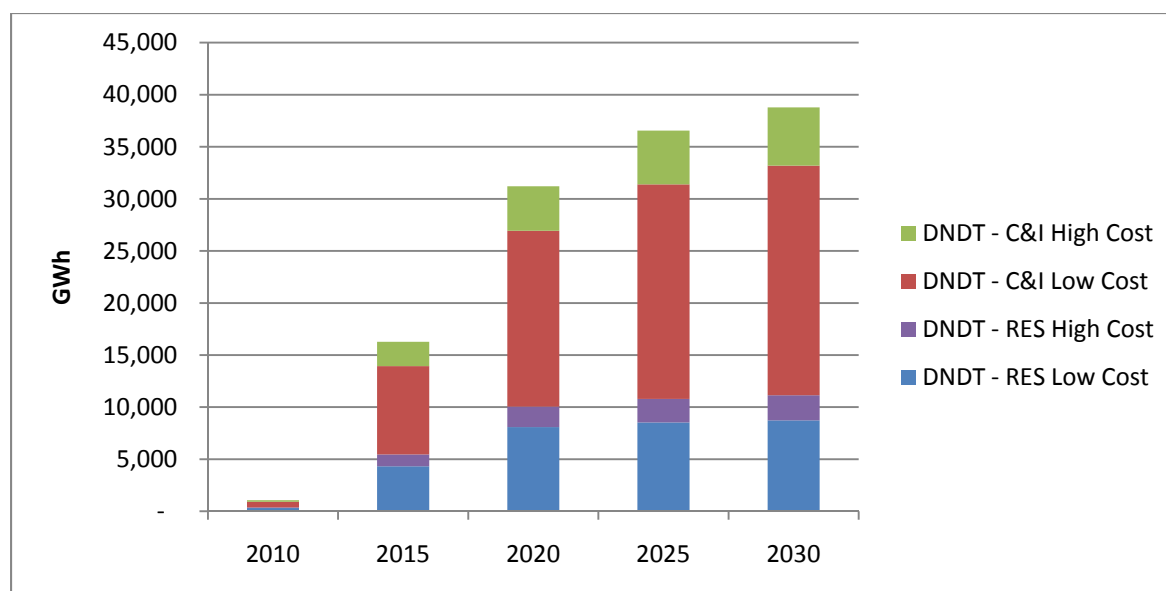
The SERC planning area covers the southern states of Alabama, Georgia, Mississippi, North Carolina, and South Carolina. With the exception of North Carolina, all of these states were mapped to the Midwest ISO East Region due to the lack of current state legislation that sets energy savings goals and general lack of existing program implementation experience in the region.²⁸ North Carolina was mapped to the Midwest ISO Central Region due to the existence of state legislation requiring utilities to offset load growth through energy efficiency.²⁹ With the exception of North Carolina, the savings per participant figures were adjusted to reflect the warmer climate (and thus higher cooling energy consumption) in these states relative to the Midwest ISO regions.

The following figures and tables show that cumulative energy savings will reach over 38,700 GWh (almost 10% of baseline) by 2030, and cumulative demand savings will reach over 7,400 MW (over 8% of baseline) by 2030. SERC ranks at number two for both energy and demand savings in the comparison of savings potential within the ten RTO/ISO planning areas. This result is consistent with the fact that SERC is the second-most populous region amongst the ten RTO/ISO planning areas in terms of number of customers.

Table 3-80 SERC – Cumulative Energy Savings by EE Program Cost (GWh)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	308	4,323	8,085	8,535	8,734
DNDT - RES High Cost	71	1,132	1,964	2,262	2,413
Total RES	379	5,455	10,048	10,797	11,147
DNDT - C&I Low Cost	533	8,492	16,890	20,592	22,041
DNDT - C&I High Cost	149	2,329	4,275	5,162	5,589
Total C&I	682	10,821	21,165	25,755	27,630
Total SERC (Eastern Int.)	1,061	16,276	31,213	36,552	38,777

Figure 3-39 SERC – Cumulative Energy Savings by EE Program Cost

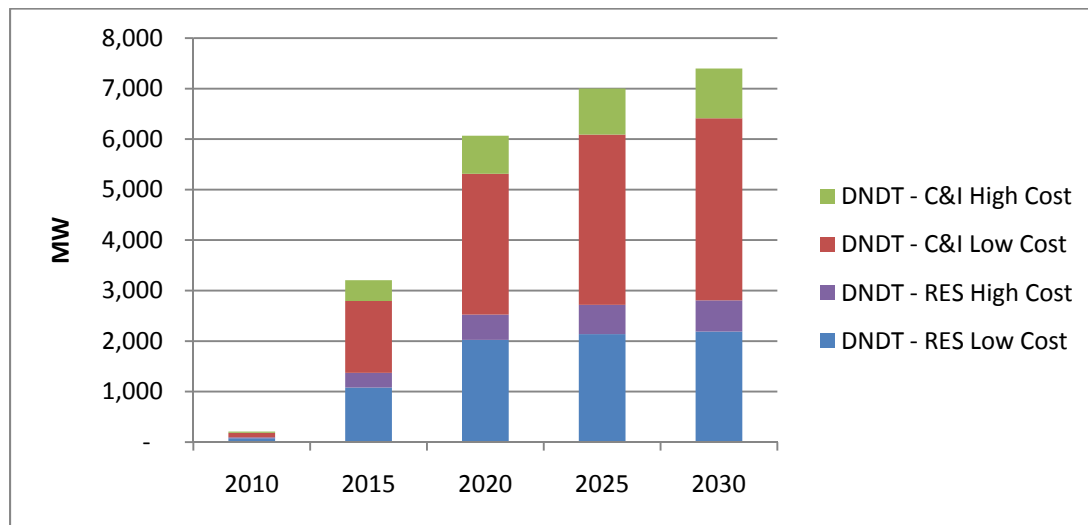


²⁸ Within the context of the approach used for the Eastern Interconnection, the Midwest ISO East Region is used to represent regions that generally do not have significant experience with energy efficiency program implementation and/or are not required to achieve specific energy-efficiency goals by state legislation.

²⁹ Within the context of the approach used for the Eastern Interconnection, the Midwest ISO Central Region is used to represent regions that are relatively new to energy-efficiency program implementation but utilities in these regions are planning and/or are mandated to aggressively pursue energy efficiency in the future.

Table 3-81 SERC – Cumulative Demand Savings by EE Program Cost (MW)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	76	1,080	2,023	2,138	2,189
DNDT - RES High Cost	18	290	503	579	618
Total RES	94	1,370	2,526	2,717	2,807
DNDT - C&I Low Cost	90	1,424	2,786	3,373	3,605
DNDT - C&I High Cost	26	412	756	912	988
Total C&I	116	1,836	3,542	4,286	4,593
Total SERC (Eastern Int.)	210	3,206	6,068	7,003	7,400

Figure 3-40 SERC – Cumulative Demand Savings by EE Program Cost**Table 3-82 SERC – Program Budget Requirement (\$ millions)**

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$34	\$123	\$54	\$11	\$6
DNDT - RES High Cost	\$44	\$200	\$87	\$40	\$24
Total RES	\$78	\$323	\$140	\$51	\$29
DNDT - C&I Low Cost	\$56	\$253	\$178	\$80	\$37
DNDT - C&I High Cost	\$49	\$199	\$118	\$65	\$39
Total C&I	\$105	\$453	\$296	\$145	\$76
Total SERC	\$183	\$776	\$436	\$196	\$105

Table 3-83 SERC – Average Cost per kWh Saved

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$0.11	\$0.12	\$0.14	\$0.18	\$0.20
DNDT - RES High Cost	\$0.62	\$0.76	\$0.82	\$0.91	\$1.01
Total RES (weighted average)	\$0.21	\$0.26	\$0.29	\$0.48	\$0.56
DNDT - C&I Low Cost	\$0.11	\$0.12	\$0.14	\$0.16	\$0.19
DNDT - C&I High Cost	\$0.33	\$0.36	\$0.43	\$0.51	\$0.61
Total C&I (weighted average)	\$0.15	\$0.17	\$0.19	\$0.23	\$0.29
Total SERC (weighted average)	\$0.17	\$0.20	\$0.22	\$0.27	\$0.34

3.3.2.9 SPP

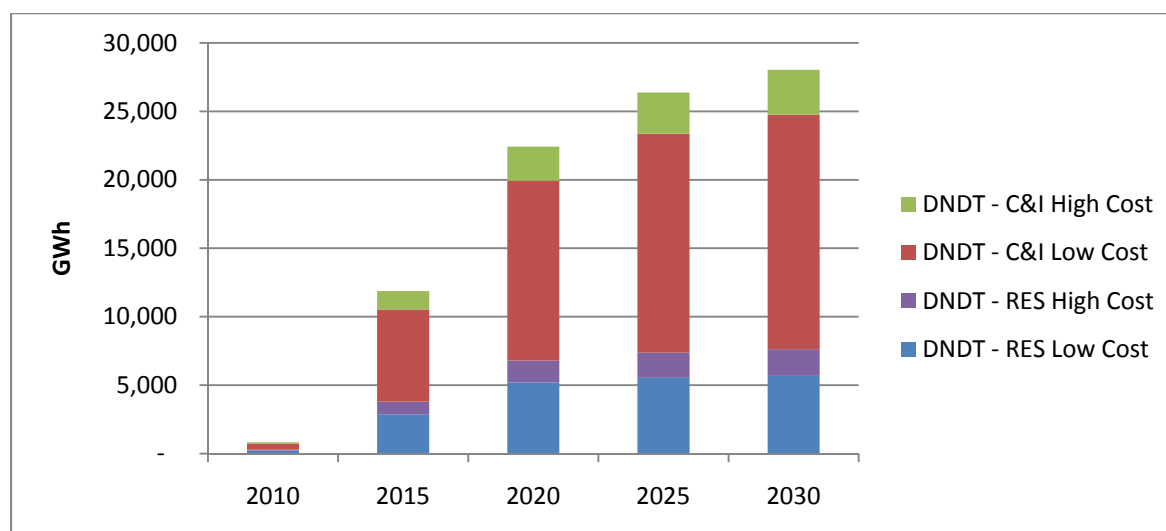
The SPP planning area covers the states of Arkansas, Kansas, Louisiana, Missouri, Nebraska, New Mexico, Oklahoma, and Texas. Arkansas, Kansas, Louisiana, and Nebraska were mapped to the Midwest ISO East Region due to the lack of current state legislation that sets energy savings goals and general lack of existing program implementation experience in the region.³⁰ Missouri, New Mexico, Oklahoma, and Texas were mapped to the Midwest ISO Central Region due to the existence of state legislation requiring utilities to offset load growth through energy efficiency and/or some utilities within those states having some experience with implementing energy-efficiency programs.³¹ For Louisiana, New Mexico, and Texas, the savings per participant figures were adjusted to reflect the warmer climate (and thus higher cooling energy consumption) in these states relative to the Midwest ISO regions.

The following figures and tables show that cumulative energy savings will reach over 28,000 GWh (over 12% of baseline) by 2030, and cumulative demand savings will reach over 5,300 MW (over 10% of baseline) by 2030. SPP ranks at number four for energy savings and number six for demand savings in the comparison of savings potential within the ten RTO/ISO planning areas. This result is consistent with the fact that SPP is the fifth-most populous region amongst the ten RTO/ISO planning areas in terms of number of customers.

Table 3-84 SPP – Cumulative Energy Savings by EE Program Cost (GWh)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	226	2,868	5,191	5,538	5,676
DNDT - RES High Cost	61	931	1,604	1,835	1,949
Total RES	287	3,800	6,795	7,372	7,625
DNDT - C&I Low Cost	441	6,722	13,145	15,996	17,133
DNDT - C&I High Cost	93	1,349	2,487	3,014	3,278
Total C&I	534	8,071	15,632	19,010	20,410
Total SPP (Eastern Int.)	821	11,871	22,426	26,382	28,035

Figure 3-41 SPP – Cumulative Energy Savings by EE Program Cost

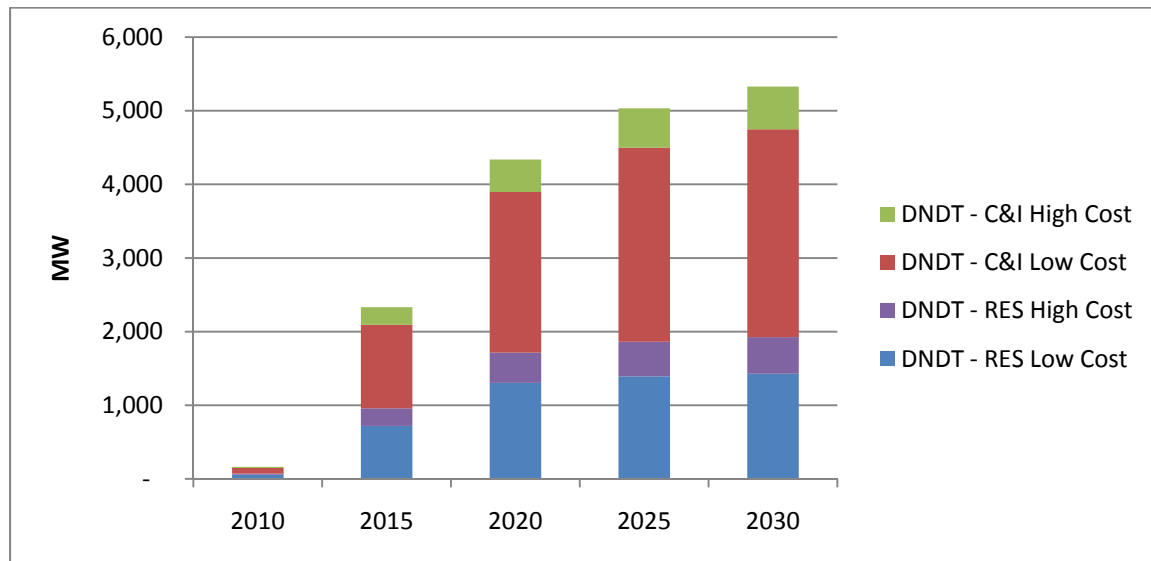


³⁰ Within the context of the approach used for the Eastern Interconnection, the Midwest ISO East Region is used to represent regions that generally do not have significant experience with energy efficiency program implementation and/or are not required to achieve specific energy-efficiency goals by state legislation.

³¹ Within the context of the approach used for the Eastern Interconnection, the Midwest ISO Central Region is used to represent regions that are relatively new to energy-efficiency program implementation but utilities in these regions are planning and/or are mandated to aggressively pursue energy efficiency in the future.

Table 3-85 SPP – Cumulative Demand Savings by EE Program Cost (MW)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	56	721	1,303	1,392	1,428
DNDT - RES High Cost	16	239	411	470	499
Total RES	72	959	1,714	1,862	1,926
DNDT - C&I Low Cost	75	1,134	2,182	2,638	2,821
DNDT - C&I High Cost	17	239	441	534	580
Total C&I	92	1,374	2,623	3,171	3,402
Total SPP (Eastern Int.)	164	2,333	4,337	5,033	5,328

Figure 3-42 SPP – Cumulative Demand Savings by EE Program Cost**Table 3-86 SPP – Program Budget Requirement (\$ millions)**

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$29	\$93	\$39	\$9	\$4
DNDT - RES High Cost	\$26	\$112	\$50	\$23	\$14
Total RES	\$55	\$205	\$89	\$32	\$18
DNDT - C&I Low Cost	\$48	\$204	\$140	\$64	\$30
DNDT - C&I High Cost	\$33	\$123	\$75	\$42	\$27
Total C&I	\$81	\$327	\$215	\$106	\$57
Total SPP	\$137	\$532	\$304	\$138	\$75

Table 3-87 SPP – Average Cost per kWh Saved

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$0.13	\$0.14	\$0.17	\$0.20	\$0.22
DNDT - RES High Cost	\$0.43	\$0.53	\$0.59	\$0.69	\$0.78
Total RES (weighted average)	\$0.19	\$0.24	\$0.28	\$0.41	\$0.49
DNDT - C&I Low Cost	\$0.11	\$0.13	\$0.14	\$0.17	\$0.20
DNDT - C&I High Cost	\$0.36	\$0.39	\$0.46	\$0.55	\$0.67
Total C&I (weighted average)	\$0.15	\$0.17	\$0.19	\$0.23	\$0.29
Total SPP (weighted average)	\$0.17	\$0.19	\$0.21	\$0.26	\$0.32

3.3.2.10 TVA

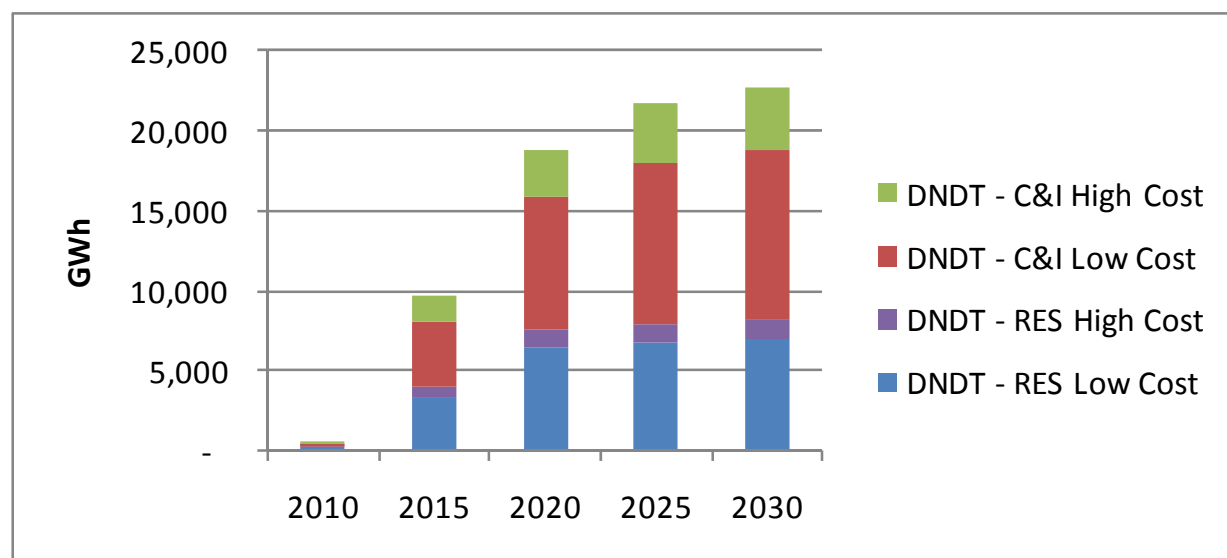
The TVA planning area covers the states of Alabama, Kentucky, Missouri, Mississippi, North Carolina, and Tennessee. Missouri, North Carolina, and Tennessee were mapped to the Midwest ISO Central Region due to the existence of state legislation requiring utilities to offset load growth through energy efficiency and/or some utilities within those states having some experience with implementing energy-efficiency programs.³² Alabama, Kentucky, and Mississippi were mapped to the Midwest ISO East Region due to the lack of current state legislation that sets energy savings goals and general lack of existing program implementation experience in the region.³³ For Alabama and Mississippi, the savings per participant figures were adjusted to reflect the warmer climate (and thus higher cooling energy consumption) in these states relative to the Midwest ISO regions.

The following figures and tables show that cumulative energy savings will reach over 22,7500 GWh (over 9.4% of baseline) by 2030, and cumulative demand savings will reach over 4,400 MW (6% of baseline) by 2030.

Table 3-88 TVA – Cumulative Energy Savings by EE Program Cost (GWh)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	230	3,438	6,514	6,780	6,924
DNDT - RES High Cost	37	626	1,057	1,205	1,274
Total RES	267	4,065	7,571	7,985	8,198
DNDT - C&I Low Cost	235	4,032	8,241	10,028	10,667
DNDT - C&I High Cost	100	1,678	3,040	3,638	3,906
Total C&I	335	5,710	11,282	13,666	14,573
Total TVA (Eastern Int.)	602	9,775	18,853	21,651	22,771

Figure 3-43 TVA – Cumulative Energy Savings by EE Program Cost

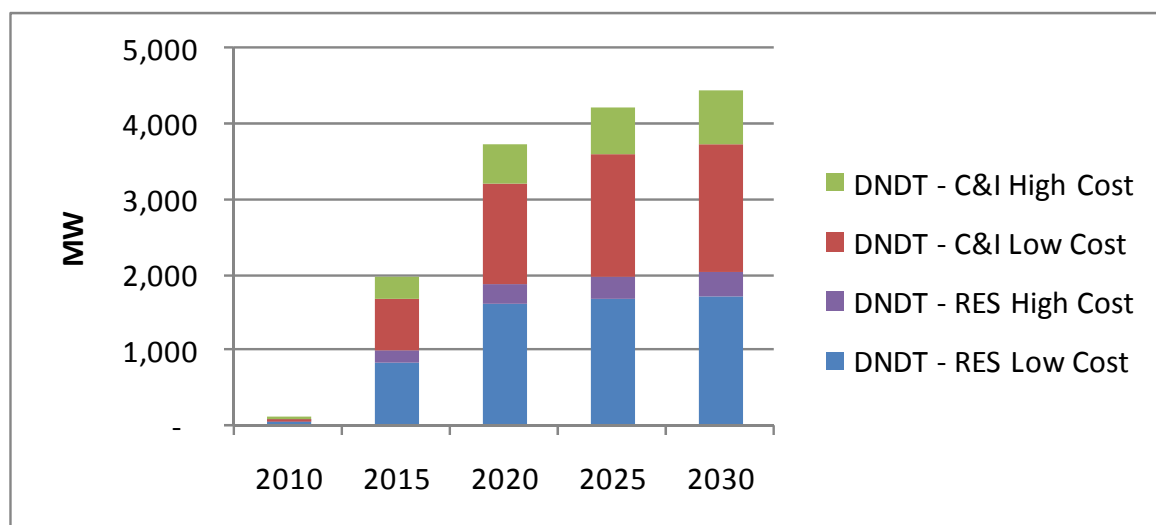


³² Within the context of the approach used for the Eastern Interconnection, the Midwest ISO Central Region is used to represent regions that are relatively new to energy-efficiency program implementation but utilities in these regions are planning and/or are mandated to aggressively pursue energy efficiency in the future.

³³ Within the context of the approach used for the Eastern Interconnection, the Midwest ISO East Region is used to represent regions that generally do not have significant experience with energy efficiency program implementation and/or are not required to achieve specific energy-efficiency goals by state legislation.

Table 3-89 TVA – Cumulative Demand Savings by EE Program Cost (MW)

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	54	844	1,608	1,675	1,711
DNDT - RES High Cost	9	161	271	309	326
Total RES	63	1,004	1,878	1,984	2,038
DNDT - C&I Low Cost	39	660	1,328	1,603	1,702
DNDT - C&I High Cost	18	296	536	642	689
Total C&I	56	956	1,864	2,245	2,391
Total TVA (Eastern Int.)	120	1,961	3,742	4,228	4,428

Figure 3-44 TVA – Cumulative Demand Savings by EE Program Cost**Table 3-90 TVA – Program Budget Requirement (\$ millions)**

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$19	\$76	\$32	\$5	\$3
DNDT - RES High Cost	\$42	\$197	\$81	\$37	\$21
Total RES	\$61	\$272	\$114	\$42	\$24
DNDT - C&I Low Cost	\$23	\$114	\$83	\$34	\$14
DNDT - C&I High Cost	\$29	\$133	\$74	\$38	\$20
Total C&I	\$52	\$247	\$157	\$73	\$35
Total TVA	\$113	\$519	\$271	\$115	\$59

Table 3-91 TVA – Average Cost per kWh Saved

Block	2010	2015	2020	2025	2030
DNDT - RES Low Cost	\$0.08	\$0.10	\$0.11	\$0.13	\$0.15
DNDT - RES High Cost	\$1.14	\$1.35	\$1.53	\$1.77	\$2.02
Total RES (weighted average)	\$0.23	\$0.29	\$0.33	\$0.69	\$0.74
DNDT - C&I Low Cost	\$0.10	\$0.11	\$0.13	\$0.15	\$0.18
DNDT - C&I High Cost	\$0.29	\$0.33	\$0.39	\$0.45	\$0.53
Total C&I (weighted average)	\$0.16	\$0.18	\$0.19	\$0.23	\$0.29
Total TVA (weighted average)	\$0.19	\$0.22	\$0.23	\$0.31	\$0.39

SCENARIO ANALYSIS

4.1 SCENARIO ANALYSIS OBJECTIVES

The analysis presented in the previous chapters represents a reference forecast for Midwest ISO's planning effort. As described above, it includes a baseline forecast (before additional utility programs) and a forecast of EE and DR impacts for the Eastern Interconnect³⁴. As a reference forecast, it embodies the most likely set of assumptions, given what we know today, and results in a "best" forecast of what is likely to happen. Because reality will vary from these assumptions, it is useful to develop a set of scenarios which represent different futures yielding different "best plans." A future is a prediction of what "could be" which guides the assumptions made about the variables within the model.

The Midwest ISO will use the results of the reference forecast and the scenario analysis in their transmission planning model, EGEAS. The outcome of each future is a generation expansion plan referred to as a generation portfolio. The generation portfolios are the capacity expansion results from a "least cost" optimization of future generation requirements based on the specified resource adequacy criteria. Each generation portfolio identifies the optimal "least cost" generation required to meet reliability criteria based on the assumptions for each future scenario.

As part of its Cost Allocation and Regional Planning (CARP) and Planning Advisory Committee (PAC) activities, Midwest ISO has developed a number of scenarios and four of these were analyzed in this study:

5. S2: CARP Federal RPS Future
6. S10: PAC Carbon Future – Carbon Cap with Nuclear
7. S1: CARP Business as Usual with High Growth Rate for Demand and Energy
8. S4: CARP Federal RPS + Carbon Cap + Smart Grid + Electric Cars

For convenience, we developed a short label for each scenario. The labels, together with the weights the Midwest ISO has assigned to each scenario are:

Midwest ISO Scenario Name	Label	Weight
S8: Reference Case (original analysis)	Reference	34%
S2: CARP Federal RPS Future	S2 RPS	26%
S10: PAC Carbon Future – Carbon Cap and Trade with Nuclear	S10 Carbon Cap	15%
S1: CARP Business as Usual with High Growth Rate for Demand and Energy	S1 High Growth	14%
S4: CARP Federal RPS, Carbon Cap and Trade, Smart Grid and Electric Cars	S4 Ultra Green	11%

4.2 SCENARIO DESCRIPTIONS

Midwest ISO staff provided the verbal descriptions of each scenario from the Midwest ISO Transmission Expansion Plan 2010 (MTEP 10)³⁵, as well as the spreadsheet of values assigned to each of the uncertainty variables³⁶. Using these values, Midwest ISO staff also developed an electricity price forecast for each scenario³⁷. In this section, we provide a short description of each scenario, the Midwest ISO price forecast, and the modeling assumptions we made for each scenario in the analysis.

³⁴ The reference forecast aligns with the future that Midwest ISO calls "S8: PAC Business as Usual with Mid-Low Demand and Energy Growth."

³⁵ Appendix F-3 of Midwest ISO Transmission Expansion Plan 2010: Future Scenarios Rate Impact Methodology (File: MTEP10_Appendix_F3_Rate_Impacts_rev4_draft_08262010)

³⁶ MTEP 10 Futures 3-18-10.xls

³⁷ Price Forecasts_MISO Scenarios_Rev1.xls provided by Wah Sing Ng, Ng Planning

4.2.1 S2 RPS

The S2 RPS scenario aligns with Midwest ISO's S2: CARP Federal RPS Future. This scenario requires that 20% of the energy consumption in the Eastern Interconnect come from wind by 2025. To model this, wind generation will begin to be forced into the models starting in 2012, accounting for the two-year lead time assumed for generation. Capacity factors for existing wind generators are taken from the NREL dataset while future wind units vary regionally from 35%-45%. Solar is modeled with a 10% annual capacity factor. Hydro and biomass are modeled with 50% annual capacity factors. State mandates are held true to the Business as Usual Future and any additional renewable energy is met with wind to satisfy the 20% renewable energy requirement. All wind is sited onshore.

Midwest ISO assumes that electricity prices increase 23% from \$8.52/MWh in 2010 to \$10.45/MWh in 2025 in this scenario.

Modeling Assumptions for S2 RPS

In general, this scenario affects the demand response programs directly, but there is little impact on the baseline forecast and the energy-efficiency programs. The key assumptions are as follows:

- **Baseline forecast.** The only impact on the baseline forecast comes from the higher electricity prices for this forecast. Prices under the S2 RPS scenario increase through 2020, but then decrease through 2030. As a result, the baseline peak and energy usage is slightly lower than the reference forecast for the first few years, but then increases slightly through 2030. By 2030, the baseline energy and demand is about one percent higher than the Reference case.
- **EE programs.** We assume a slight increase in participation in energy efficiency programs due to the increase in electricity prices and an overall awareness of the RPS standard. However, since the programs themselves do not change significantly under this scenario, we do not assume any changes to the savings per participant.
- **DR programs.** For demand response, the utilities will encourage permanent load shifting (PLS) and there will be more emergency DR to offset the intermittency of wind. To reflect PLS and to align with EGEAS, we added an analysis bucket for storage (DSTO). Typically included in the DSTO bucket are cogeneration, combined heat and power, thermal energy storage, battery storage, etc. For our analysis, we created two sub-categories within the storage (DSTO) bucket – emergency cogeneration and storage. We assume that the storage technologies are available only to C&I customers, so the DSTO bucket applies only to them.

For the DR program analysis, we have expanded “Fast DR” as another option in the DHYD bucket. Fast DR is when a C&I customer is able to reduce power usage automatically and quickly – typically within 10 minutes. For all of the DR programs, utilities will need to spend more money on marketing the programs and offer more options and technologies in order to capture additional DSM beyond the low-hanging fruit. Therefore, the cost per kW will increase for the programs. Participation rates for all DR programs will increase slightly, in the range of 1% to 5% in absolute terms. We also assume that 25% of existing direct load control customers switch to the Fast DR program.

4.2.2 S10 Carbon Cap

The S10 Carbon Cap scenario aligns with the Midwest ISO PAC's S10: PAC Carbon Future – Carbon Cap and Trade with Nuclear. This scenario embodies a declining cap on future CO₂ emissions. The carbon cap is modeled after the Waxman-Markey bill, which has an 83% reduction of CO₂ emissions from a 2005 baseline by the year 2050. That target is achieved through a linear reduction from 2010 to 2050 with mid-point goals of 3% reduction in 2012, 17% reduction in 2020 and 42% reduction in 2030. This future deploys uneconomic coal retirements, oldest and highest heat-rate coal units are retired first, and also IGGC with sequestration and CC with sequestration technologies do not mature fast enough to become an option within the study period.

Per the Midwest ISO scenario description, electricity prices increase 30% from \$8.52/MWh in 2010 to \$11.08/MWh in 2025, the demand growth rate decreases from 0.75% in the Reference case to 0.3% under this scenario and the energy growth rate decreases from 1.0% in the Reference case to 0.3%.

Modeling Assumptions for S10 Carbon Cap

In general, this scenario affects the energy efficiency programs the most, but there is also an impact on the baseline forecast and the demand response programs. The key assumptions are as follows:

- **Baseline forecast.** The baseline forecast is affected by a decrease in peak and energy sales, as well as the effect from the higher electricity prices for this forecast. Prices under the S10 Carbon Cap scenario increase through 2015, but then level off through 2030. As a result, the baseline peak and energy usage is lower than the Reference case through 2030. By 2030, the baseline energy is about four percent lower than the Reference case and baseline peak is two percent lower.
- **EE programs.** We assume a slight increase in participation in energy efficiency programs due to the increase in electricity prices and an overall awareness of the Carbon Cap legislation. The savings per participant are assumed to increase slightly since the EE programs will also likely include more advanced technologies. For example, the lighting program might introduce LEDs earlier than they would have otherwise, which provides more savings than switching to CFLs. Due to rate increases, we assume that utilities will be under increasing regulator pressure to tap into demand side resources as much as they can, effectively increasing the costs. As the focus moves beyond the low-hanging fruit, the cost per kWh saved increases.
- **DR programs.** The impact from DR programs will be less than from energy efficiency programs, but will still increase slightly as a result of increased participation in DR programs. Participation rates in DR programs are assumed to increase as more customers sign up for the programs in reaction to the increase in electricity prices and overall awareness of the Carbon Cap legislation.

4.2.3 S1 High Growth

The S1 High Growth scenario is considered the status quo future, except with a quick recovery from the economic downturn in demand and energy projections. This future models the power system as it exists today with reference case values and trends, with the exception of demand and energy growth rates. These growth rates are based on recent historical data and assume that existing standards for resource adequacy, renewable mandates, and environmental legislation will remain unchanged. Renewable Portfolio Standard (RPS) requirements vary by state, and have many potential resources that can apply. RPS requirements will be met with the percent breakdown defined for each state from the CARP negotiators.

In accordance with the Midwest ISO assumptions for this scenario, electricity prices increase 6% from \$8.52/MWh in 2010 to \$9.02/MWh in 2025, the demand growth rate increases from 0.75% in the reference case to 1.6%, and the energy growth rate increases from 1.0% in the reference case to 2.19%.

Modeling Assumptions for S1 High Growth

In this scenario, the baseline forecast is affected the most, with savings from EE and DR programs coming from the increase in customers. Key assumptions include the following:

- **Baseline forecast.** The baseline forecast is affected by an increase in the growth rates for number of customers, energy and peak sales. For this scenario, we reviewed the utility-provided data for the baseline forecast to smooth out any effects due to the recession. We did this by replacing any negative annual growth rates with the long-term average growth rate for the region. The only class and region significantly affected in the years after 2010 is the residential class in the East Region. We also assumed an increase in the number of residential households and C&I customers as a reflection of an economic recovery. While energy and peak sales are expected to increase due to the economic recovery, they are tempered with a slight decrease as a result of higher electricity prices.
- **EE programs.** The savings from EE programs increase under the S1 High Growth scenario due to the increase in the number of customers. With an increase in the number of customers, there is a larger population from which to obtain participants for EE programs. The savings per participant and the cost per kWh savings are assumed to remain the same as the Reference case.
- **DR programs.** As with the EE programs, the savings from DR programs increase. Under the S1 High Growth scenario there are more customers and therefore an increase in the number of participants in DR programs. The savings per participant and the cost per kW savings are assumed to remain the same as the Reference case.

4.2.4 S4 Ultra Green

The S4 Ultra Green scenario aligns with the Midwest ISO's S4: CARP Federal RPS, Carbon Cap and Trade, Smart Grid and Electric Cars. This scenario includes every potential policy outcome contained in the full set of Midwest ISO scenarios: a federal RPS, a carbon cap and trade, smart grid and electric vehicles. For brevity, we call this the Ultra Green scenario. In this scenario, we model the RPS aspect the same way as in the S2 RPS scenario and the carbon cap legislation the same way as in S10 Carbon Cap. The effect of the smart grid is captured with the demand growth rate – we assume that the implementation of the smart grid and smart meters will enable customers to participate in demand response in greater numbers, lowering the overall growth of demand. Finally the effect of the electric vehicles is captured with the energy growth rate. Electric vehicles are assumed to increase off-peak energy usage and, as such, increase the overall energy growth rate. This scenario also causes a change to the load shape.

According to the Midwest ISO description for this scenario, electricity prices increase 53% from \$8.52/MWh in 2010 to \$13.07/MWh in 2025. The changes in demand and energy growth rates are the same as under S10 Carbon Cap, which assumes that the demand growth rate decreases from 0.75% in the Reference case to 0.3% and that the energy growth rate decreases from 1.0% in the reference case to 0.3%.

Modeling Assumptions for S4 Ultra Green

This future is a combination of S2 and S10, plus some. In general, this scenario affects everything – the baseline forecast, energy efficiency programs, demand response programs, and load shapes. The key assumptions are as follows:

- **Baseline forecast.** This scenario includes several competing factors. The baseline forecast is affected by the decrease in peak and energy sales, the effect from the significantly higher electricity prices, the effect of the smart grid on peak demand, and an increase in energy sales due to the plug-in electric vehicles. Consumption of energy is assumed to decrease in this scenario due to the heightened awareness of environmental issues and a pro-conservation attitude. Prices under the S4 Ultra Green scenario increase steadily through 2025, but then level off through 2030. The addition of the smart grid is likely to lead to better load management, therefore further reducing peak demand. However, a competing

force is the increase in energy sales for the residential sector due to the prevalence of electric vehicles. According to the Midwest ISO's assumptions on electric vehicles, there will be 1,367,851 electric cars in 2029 and the average electricity use per vehicle per year is 6,246 kWh³⁸. The net result of the competing factors is that baseline peak and energy usage is significantly lower than the Reference case through 2030. In 2030, the baseline energy and peak are about 10 percent lower than the Reference case.

- **EE programs.** We assume a significant increase in participation in energy efficiency programs due to the significant increase in electricity prices and an overall awareness of the environment through RPS and Carbon Cap legislation. Like in the S10 Carbon Cap scenario, the savings per participant is assumed to increase slightly since the EE programs will also include more advanced technologies which achieve greater savings. Due to rate increases, we assume that utilities will be under increasing regulator pressure to tap into demand side resources as much as they can, effectively increasing the costs. As the focus moves beyond the low-hanging fruit, the cost per kWh saved increases.
- **DR programs.** Participation rate increases are assumed to be highest under this scenario, due to the combined effects of the highest retail rate increases, smart grid activities, and a high level of customer awareness and interest related to energy and environmental matters. The smart grid enables dynamic pricing on a broad scale and we set the participation rates equal to those in the FERC Achievable Potential scenario. Due to RPS, we added the DSTO storage bucket and Fast DR to offset the intermittency of wind power.
- **Load shapes.** For this analysis we assume that customers will be incentivized to charge during off-peak hours and that there will be different load shapes for the weekday versus the weekend. In creating the weekday load shape we assumed that the peak hour for charging is 10 pm and the majority of the charging lasts until 6 am. We assumed that some people will still need to charge their car during the day so have left about 10% of the peak charging during peak hours. For the weekend shape, the restriction of charging during off-peak hours is no longer there, but the general shape will still persist. For the weekend shape we assume that the peak again occurs at 10 pm, but it is only at 80% of the weekday peak. Figure 4-1 and Figure 4-2 show the resulting load shapes as a result of plug-in electric vehicles.

³⁸ Derived from analysis in "Assessment of Plug-in Electric Vehicle Integration with ISO/RTO Systems," KEMA, March 2010. Assumptions include 65% of vehicles charging on average, the average PEV rating is 3.3 kW (based on Nissan Leaf's rating), cars are charging 364 days a week for 8 hours a day for a total of 2,912 hours per year, and assume 1% of total energy in 2029 is from electric vehicles.

Figure 4-1 **Weekday Electric Vehicle Load Shape**

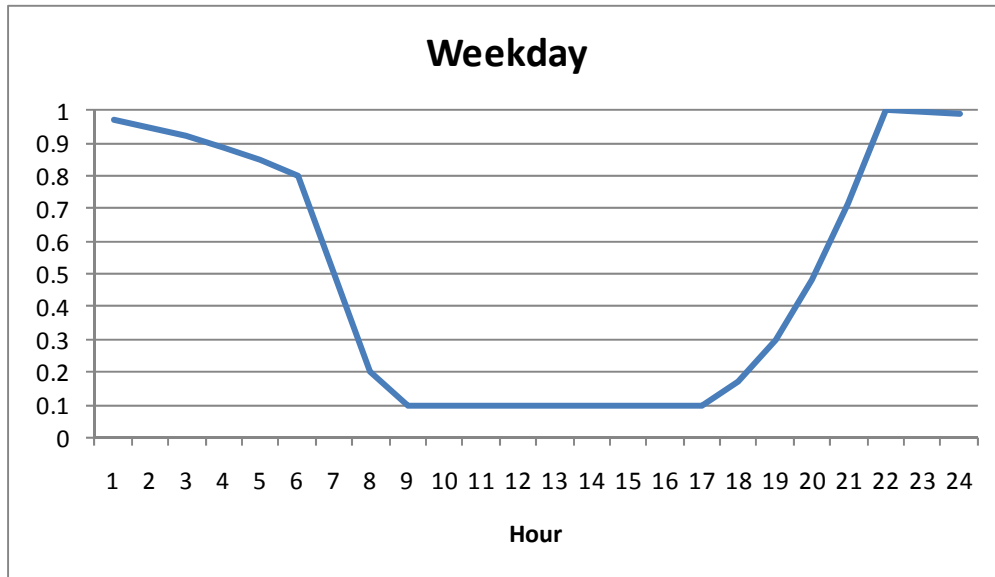
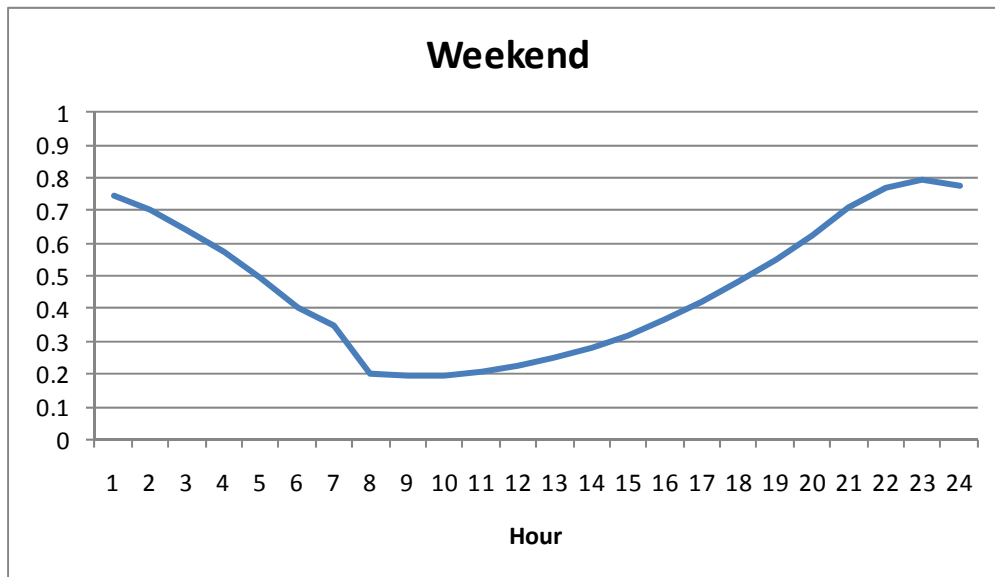


Figure 4-2 **Weekend Electric Vehicle Load Shape**



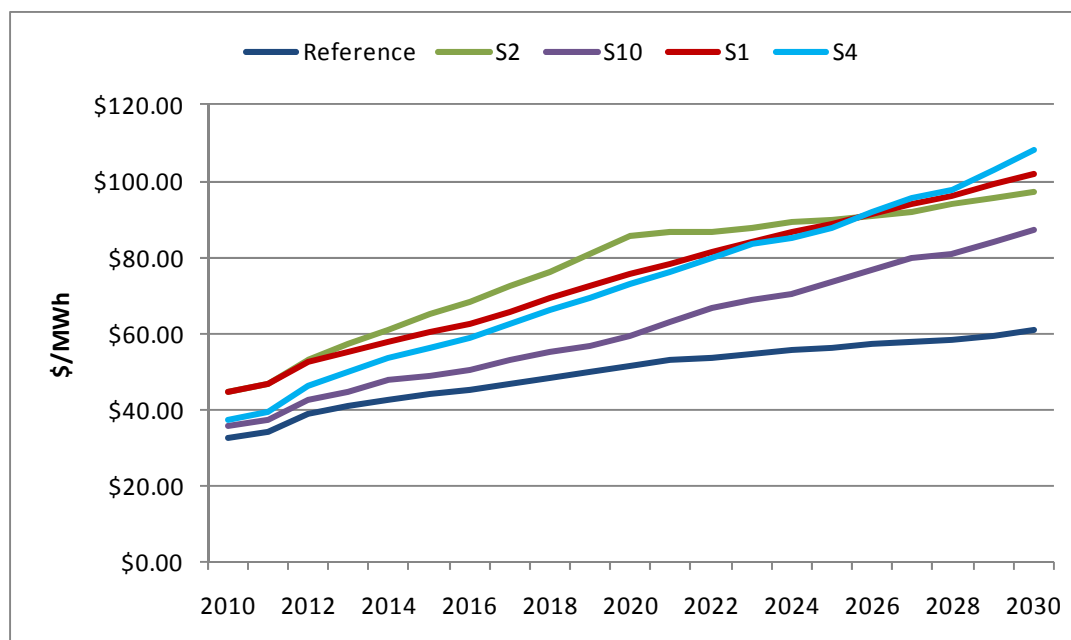
4.3 SUMMARY OF SCENARIO ASSUMPTIONS

Based on the scenario descriptions, we made changes to various analysis assumptions which drive the results. Because changes to the parameters follow the same logic for each scenario, we describe the rationale for changes to the analysis by groups of parameters, then by scenario.

4.3.1 Electricity prices

Midwest ISO provided assumptions about price changes for each scenario. These assumptions were applied to the electricity prices for each region. For summary purposes, the weighted average for the Eastern Interconnect is shown in Figure 4-3 below. Note that the analysis is done using each region's price forecast.

Figure 4-3 *Retail Electricity Price Forecast by Scenario, Eastern Interconnect*



As a result of the higher price forecasts, baseline energy use and peak demand will decrease. We applied a price elasticity of -0.15 to the Reference baseline forecast to develop the baseline forecasts for each scenario. The resulting impacts are shown in Table 4-1 below.

Table 4-1 *Changes to Energy and Peak Demand in Response to Price Changes -- 2025*

Scenario	Effect
S2 RPS Residential	-4.7% over Reference forecast
S2 RPS C&I	-4.7% over Reference forecast
S4 Carbon Cap Residential	-5.8% over Reference forecast
S4 Carbon Cap C&I	-5.8% over Reference forecast
S1 High Growth Residential	-2.2% over Reference forecast
S1 High Growth C&I	-2.2% over Reference forecast
S10 Ultra Green Residential	-9.3% over Reference forecast
S10 Ultra Green C&I	-9.3% over Reference forecast

4.3.2 Number of customers

The number of customers will only change in the S1 High Growth scenario. We increased the customer growth rate for both residential and C&I by 20% in all regions to reflect household and customer growth in the S1 High Growth scenario.

Table 4-2 *Changes to Number of Customers by Scenario*

Scenario	Effect
S2 RPS Residential	n/a
S2 RPS C&I	n/a
S10 Carbon Cap Residential	n/a
S10 Carbon Cap C&I	n/a
S1 High Growth (East) Residential	Apply a 20% increase to the growth rate 2017-2030
S1 High Growth (East) C&I	Apply a 20% increase to the growth rate 2010-2030
S4 Ultra Green Residential	n/a
S4 Ultra Green C&I	n/a

4.3.3 Peak Demand

Peak demand is affected in two ways for scenarios S10 Carbon Cap, S1 High Growth, and S4 Ultra Green. There is an effect on the peak demand growth rate and the peak demand. The S4 Ultra Green scenario also includes an effect from the smart grid. Changes in demand growth rate are applied first, and then the demand level is adjusted to account for the response to price increases.

4.3.3.1 Peak Demand Growth Rate

Midwest ISO supplied changes to demand growth rates for both the S10 Carbon Cap and the S1 High Growth scenario. The S4 Ultra Green scenario includes carbon cap, so we used the same effect in S4 Ultra Green as is used for S10 Carbon Cap. In each case, the decrease or increase is with respect to the Reference baseline forecast and the decrease or increase is applied to each year of the peak demand forecast.

Table 4-3 *Changes to Peak Demand Growth Rate by Scenario*

Scenario	Effect
S2 RPS Residential	n/a
S2 RPS C&I	n/a
S10 Carbon Cap Residential	60% decrease
S10 Carbon Cap C&I	60% decrease
S1 High Growth Residential	113% increase
S1 High Growth C&I	113% increase
S4 Ultra Green Residential	60% decrease
S4 Ultra Green C&I	60% decrease

4.3.3.2 Smart Grid

The smart grid is likely to lead to better load management practices, further reducing demand levels from 2015 onwards. This results in an 11.3% reduction (9.3% +2%) in peak demand for S4 Ultra Green in 2025.

Table 4-4 *Changes to Peak Demand Due to Smart Grid by Scenario*

Scenario	Effect
S2 RPS Residential	n/a
S2 RPS C&I	n/a
S10 Carbon Cap Residential	n/a
S10 Carbon Cap C&I	n/a
S1 High Growth Residential	n/a
S1 High Growth C&I	n/a
S4 Ultra Green Residential	-2% over baseline
S4 Ultra Green C&I	-2% over baseline

4.3.4 Energy

Energy is affected in two ways for the S10 Carbon Cap, S1 High Growth and S4 Ultra Green scenarios—the energy growth rate and the energy. The S4 Ultra Green scenario also includes an effect from the smart grid. In addition, there is an increase in the use of energy due to the increase in presence of electric vehicles in the S4 Ultra Green scenario. Changes in the energy growth rate are applied first, and then the energy level was adjusted to account for the price elasticity.

4.3.4.1 Energy Growth Rate

Midwest ISO supplied changes to energy growth rates for both the S10 Carbon Cap and the S1 High Growth scenario. The S4 Ultra Green scenario includes carbon cap, so we used the same effect in S4 Ultra Green as is used for S10 Carbon Cap. The change is applied to each year of the peak demand forecast.

Table 4-5 *Changes to Energy Growth Rate by Scenario*

Scenario	Effect
S2 RPS Residential	n/a
S2 RPS C&I	n/a
S10 Carbon Cap Residential	70% decrease
S10 Carbon Cap C&I	70% decrease
S1 High Growth Residential	119% increase
S1 High Growth C&I	119% increase
S4 Ultra Green Residential	70% decrease
S4 Ultra Green C&I	70% decrease

4.3.5 DR Participation Rates

Participation rates are affected in several ways depending on the scenario. Table 4-6 presents the changes to the participation rates from the Reference case. All of the increases are applied linearly beginning in 2010 and maxing out at 2025. Table 4-7 shows the resulting participation rates by program and scenario.

The rate increase under scenario S2 RPS is the second lowest at 23%, which results in a slight increase in the participation rates. DLC participation is assumed to increase due to the increase in wind generation beginning in 2012. This increase reflects the added emphasis on DLC as Fast DR. Permanent load shifting was added as a program to scenario S2 RPS in the storage (DSTO) bucket. The “Other DR” program represents new medium and large customers participating in Fast DR through ancillary services or Auto-DR.

Scenario S10 Carbon Cap is affected only by the rate increase and the resulting moderate increases in participation rates are shown below. The retail rate increase for Scenario S10 Carbon Cap is likely to be the second highest at 30% by 2025.

Scenario S1 High Growth is affected only by the rate increase, which is the lowest for the scenarios. The resulting slight increase in participation rates are shown below.

Scenario S4 incorporates the effects of both S2 RPS and S10 Carbon Cap combined and the DR participation rate increases are assumed to be highest under this scenario, due to the combined effects of the highest retail rate increases, smart grid activities, and a high level of customer awareness and interest related to energy and environmental matters. For the pricing programs, participation rates are matched to the FERC Achievable Potential scenario rates to represent a smart grid enabled future, with a high degree of penetration of dynamic pricing and AMI. The FERC Achievable Potential scenario assumes default dynamic pricing with opt-in. For this scenario, we assume that all customers participate in some form of DR. Once the adjustments were made to each of the other programs, the remaining participants are placed in Other DR programs.

Table 4-6 *Changes to DR Participation Rates by Program*

Program	S2 RPS	S10 Carbon Cap	S1 High Growth	S4 Ultra Green
DLC Participation Residential	33.3%	66.7%	16.7%	66.7%
DLC Participation C&I	33.3%	66.7%	16.7%	100%
Interruptible Participation	0%	0%	0%	0%
Pricing Participation Residential	20.0%	66.7%	16.7%	275%
Pricing Participation C&I	20.0%	66.7%	16.7%	500%
Other DR	33.3%	66.7%	16.7%	varies
Permanent Load Shifting	33.3%	n/a	n/a	66.7%

Table 4-7 *DR Participation Rates by Program*

Program	Reference	S2 RPS	S10 Carbon Cap	S1 High Growth	S4 Ultra Green
DLC Participation Residential	15%	20%	25%	17.5%	25%
DLC Participation C&I	2.5%	3.3%	4.2%	2.9%	5%
Interruptible Participation	0.1%	0.1%	0.1%	0.1%	0.1%
Pricing Participation Residential	20%	24%	33%	23%	75%
Pricing Participation C&I	10%	12%	17%	12%	60%
Other DR	0.14%	0.19%	0.23%	0.16%	varies
Permanent Load Shifting	0.0%	0.2%	0.0%	0.0%	0.2%

4.3.6 EE Participation Rates

Like DR programs, participation rates for energy-efficiency programs are affected in several ways depending on the scenario. Table 4-8 presents the changes to Reference case participation rate and are applied linearly beginning in 2010 and maxing out at 2025. Table 4-9 shows the resulting participation rates by program.

For scenarios S10 Carbon Cap and S4 Ultra Green, we assumed that participation rates across all programs will increase. In general, this is a result of the increase in electricity prices. Customers are more likely to participate in programs that can save them money as they attempt to cut electricity bills.

Due to the price increases under S2 RPS, the energy-efficiency participation rates for this scenario increase modestly since utilities are most likely to focus on encouraging storage and load shifting to account for the intermittency of wind power.

Scenario S10 Carbon Cap is affected only by the electricity price increase, resulting in modest increases in participation rates.

The energy-efficiency participation rates for S1 High Growth increase slightly since the increase in rates is small compared to the other scenarios.

Participation rate increases are assumed to be highest under Scenario 4 Ultra Green, due to the combined effects of the highest retail rate increases, smart grid activities, and a high level of customer awareness and interest related to energy and environmental matters.

Table 4-8 *Changes to EE Participation Rates by Program*

Residential Programs	S2 RPS	S10 Carbon Cap	S1 High Growth	S4 Ultra Green
Appliance incentives/rebates	12%	15%	6%	30%
Appliance recycling	10%	13%	5%	26%
Lighting initiatives	16%	20%	8%	40%
Low income programs	12%	15%	6%	30%
Multifamily programs	12%	15%	6%	30%
New construction programs	16%	20%	8%	40%
Whole home audit programs	6%	8%	3%	16%
All other residential programs	6%	8%	3%	16%
C&I Programs	S2 RPS	S10 Carbon Cap	S1 High Growth	S4 Ultra Green
Lighting programs	16%	20%	8%	40%
Prescriptive rebates	12%	15%	6%	30%
Custom incentives	10%	13%	5%	26%
New construction programs	16%	20%	8%	40%
RCx programs	10%	13%	5%	26%
All other C&I programs	6%	8%	3%	16%

Table 4-9 *EE Participation Rates by Program*

Residential Programs	Reference	S2 RPS	S10 Carbon Cap	S1 High Growth	S4 Ultra Green
Appliance incentives/rebates	36.5%	40.9%	42.0%	38.7%	47.5%
Appliance recycling	12.0%	13.2%	13.6%	12.6%	15.1%
Lighting initiatives	42.6%	49.4%	51.1%	46.0%	59.6%
Low income programs	6.6%	7.4%	7.6%	7.0%	8.5%
Multifamily programs	19.4%	21.7%	22.3%	20.5%	25.2%
New construction programs	0.7%	0.8%	0.9%	0.8%	1.0%
Whole home audit programs	7.7%	8.2%	8.4%	8.0%	9.0%
All other residential programs	0.4%	0.4%	0.4%	0.4%	0.5%
C&I Programs	Reference	S2 RPS	S10 Carbon Cap	S1 High Growth	S4 Ultra Green
Lighting programs	5.2%	6.0%	6.2%	5.6%	7.2%
Prescriptive rebates	45.4%	50.9%	52.3%	48.2%	59.1%
Custom incentives	2.7%	2.9%	3.0%	2.8%	3.4%
New construction programs	0.5%	0.5%	0.5%	0.5%	0.6%
RCx programs	0.5%	0.6%	0.6%	0.5%	0.6%
All other C&I programs	1.0%	1.1%	1.1%	1.0%	1.2%

4.3.7 EE Savings per Participant

For S10 Carbon Cap and S4 Ultra Green, the aggressive carbon cap on CO₂ emissions forces utilities and their customers to adopt innovative technologies that will deliver more energy savings. The RPS under S2 RPS scenario also leads to an increase in energy savings. We believe that under these scenarios there is a more aggressive adoption of new and more advanced energy-efficiency technologies. For example, LED lighting technologies can save more energy than compact fluorescent lamps, and thus lighting programs might introduce and promote LED's earlier than they would have otherwise. For the purpose of modeling, we estimated that LED's would increase the energy savings per participant for the lighting programs by approximately

12% (over the baseline). Similarly, we estimated that the adoption of new and advanced technologies will increase the energy savings per participant for the other energy-efficiency programs in the range of 2% to 10% (over the baseline).

New and advanced technologies are not expected to make an impact in scenario S1 High Growth.

Table 4-10 *Changes to EE Savings per Participant by Program*

Residential Programs	S2 RPS	S10 Carbon Cap	S1 High Growth	S4 Ultra Green
Appliance incentives/rebates	6%	8%	n/a	8%
Appliance recycling	0%	0%	n/a	0%
Lighting initiatives	12%	15%	n/a	15%
Low income programs	10%	13%	n/a	13%
Multifamily programs	8%	10%	n/a	10%
New construction programs	10%	13%	n/a	13%
Whole home audit programs	4 %	5%	n/a	5%
All other residential programs	2%	3%	n/a	3%
C&I Programs	S2 RPS	S10 Carbon Cap	S1 High Growth	S4 Ultra Green
Lighting programs	12%	15%	n/a	15%
Prescriptive rebates	6%	8%	n/a	8%
Custom incentives	8%	10%	n/a	10%
New construction programs	10%	13%	n/a	13%
RCx programs	2%	3%	n/a	3%
All other C&I programs	2%	3%	n/a	3%

4.3.8 EE Cost per kWh Saved

For energy efficiency, higher electricity prices, increase the pressure to tap into demand side resources, and changing the focus from picking 'low hanging fruit' to picking 'all fruit' also increased costs for scenarios S2 RPS, S10 Carbon Cap and S4 Ultra Green. Utilities will need to spend more money on advertising and recruitment, and will additionally need to offer more options and technologies to customers. In S4 Ultra Green, we assumed an increase of 5%, which takes into account any offsetting effects from the smart grid that requires more expensive technology, while making older technologies cheaper and more efficient through economies of scale. We assume that costs increase uniformly across programs, but vary by scenario as follows.

Table 4-11 *Changes to EE Cost per kWh Saved by Scenario*

Scenario	Effect
S2 RPS Residential	2% over Reference
S2 RPS C&I	2% over Reference
S10 Carbon Cap Residential	3% over Reference
S10 Carbon Cap C&I	3% over Reference
S1 High Growth Residential	n/a
S1 High Growth C&I	n/a
S4 Ultra Green Residential	5% over Reference
S4 Ultra Green C&I	5% over Reference

4.3.9 DR Cost per kW

We assumed that higher electricity prices, increased pressure to tap into demand side resources, and changing focus from picking 'low hanging fruit' to picking 'all fruit' also increased DR program costs for scenarios S10 Carbon Cap, S2 RPS, and S4 Ultra Green. Utilities will need to spend more money on advertising and recruitment, and will additionally need to offer more

options and technologies to customers. In S4 Ultra Green, we assumed an increase of 5%, which takes into account any offsetting effects from the smart grid that requires more expensive technology, while making older technologies cheaper and more efficient through economies of scale. We assume that costs increase uniformly across programs, but vary by scenario as follows.

Table 4-12 *Changes to DR Cost per kW Saved by Scenario*

Scenario	Effect
S2 RPS Residential	2% over Reference
S2 RPS C&I	2% over Reference
S10 Carbon Cap Residential	3% over Reference
S10 Carbon Cap C&I	3% over Reference
S1 High Growth Residential	n/a
S1 High Growth C&I	n/a
S4 Ultra Green Residential	5% over Reference
S4 Ultra Green C&I	5% over Reference

4.3.10 DR and EE Cost Escalation Rates

Cost Escalation rates are calculated based on scenario-related assumptions provided by Midwest ISO. The assumption used for each of the scenarios is a cost escalation rate of 8.39%, compared to 8.0% used in the reference case. Therefore, a 67% increase in cost escalation rates over the baseline value was derived. This is applied uniformly across all scenarios.

Table 4-13 *Changes to Cost Escalation Rates by Scenario*

Scenario	Effect
S2 RPS Residential	67% over Reference
S2 RPS C&I	67% over Reference
S10 Carbon Cap Residential	67% over Reference
S10 Carbon Cap C&I	67% over Reference
S1 High Growth Residential	67% over Reference
S1 High Growth C&I	67% over Reference
S4 Ultra Green Residential	67% over Reference
S4 Ultra Green C&I	67% over Reference

4.4 RESULTS

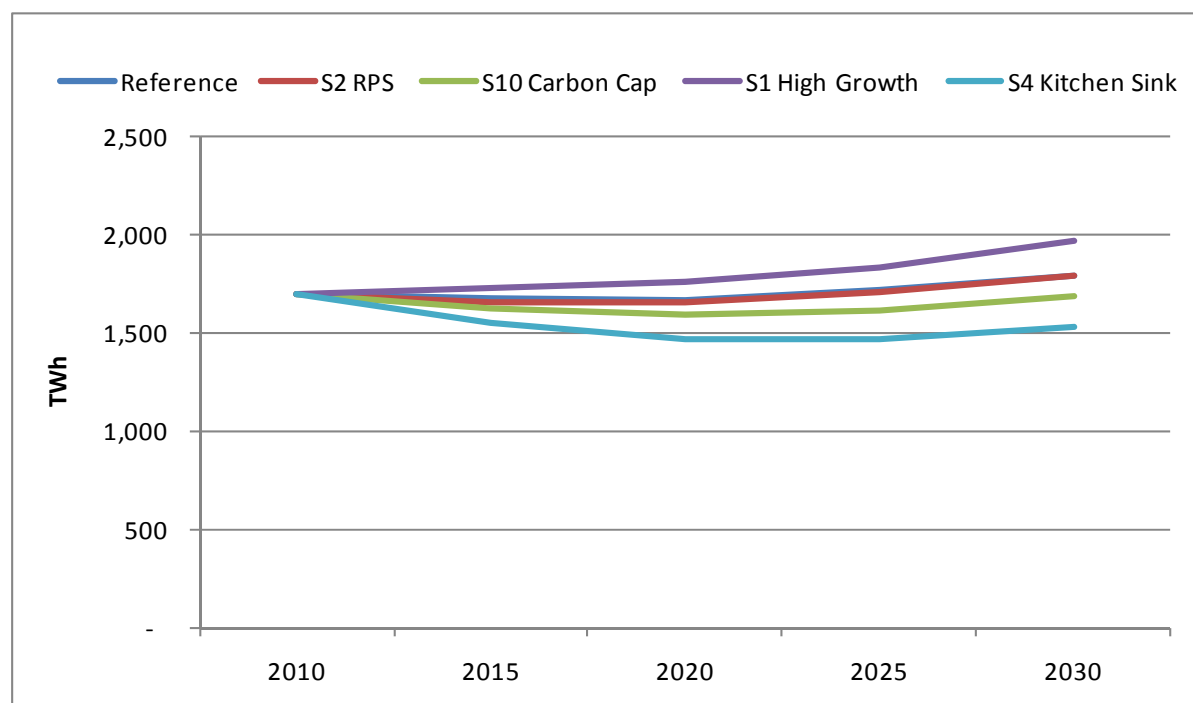
4.4.1 Baseline Energy Forecast

Table 4-14 and Figure 4-4 show the effect the changes to the key assumptions have on the baseline energy use forecast for each scenario. The S1 High Growth scenario shows that with the recovery there is a significant increase in the baseline energy use. Although the electric vehicles in the S4 Ultra Green scenario increase the energy significantly it is tempered by the competing effects of the RPS and Carbon Cap.

Table 4-14 Baseline Energy Forecast by Scenario (TWh)

	2010	2015	2020	2025	2030	% Increase (2010-30)	Average Annual Growth (%)
Reference	1,696	1,673	1,663	1,716	1,795	5.8%	0.3%
S2 RPS	1,695	1,654	1,652	1,708	1,789	5.5%	0.3%
S10 Carbon Cap	1,695	1,627	1,593	1,619	1,684	-0.7%	0.0%
S1 High Growth	1,696	1,733	1,755	1,838	1,964	15.8%	0.7%
S4 Ultra Green	1,695	1,554	1,470	1,472	1,529	-9.8%	-0.5%

Figure 4-4 Baseline Energy Forecast by Scenario



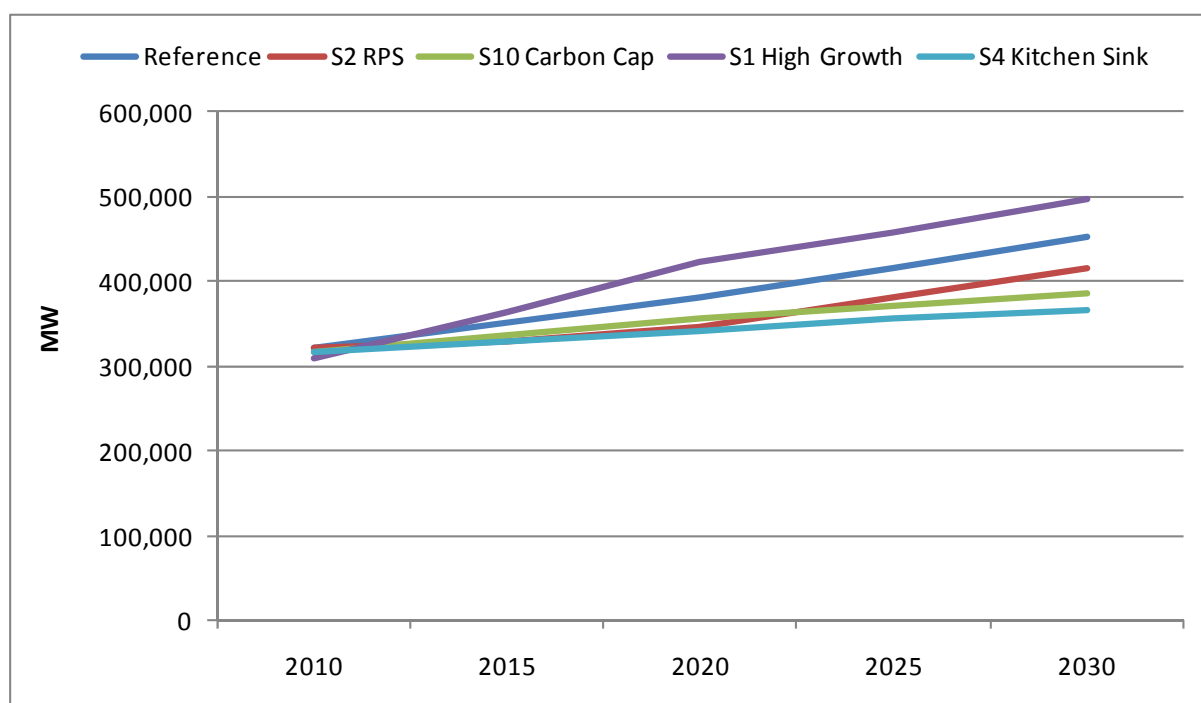
4.4.2 Baseline Demand Forecast

Table 4-15 and Figure 4-5 show the effect the changes to the key assumptions have on the baseline demand forecast for each scenario before any effect from EE or DR programs. The S1 High Growth scenario shows that with the economic recovery there is an increase in the baseline demand.

Table 4-15 Baseline Demand Forecast by Scenario (MW)

	2010	2015	2020	2025	2030	% Increase (2010-30)	Average Annual Growth (%)
Reference	321,693	350,215	381,101	414,824	451,667	40.4%	1.7%
S2 RPS	321,052	328,667	345,961	380,600	414,553	29.1%	1.3%
S10 Carbon Cap	317,934	336,561	356,721	370,475	386,704	21.6%	1.0%
S1 High Growth	309,241	364,909	422,736	458,429	497,682	60.9%	2.4%
S4 Ultra Green	315,974	328,684	342,200	355,675	366,355	15.9%	0.7%

Figure 4-5 Baseline Demand Forecast by Scenario



4.4.3 Peak Demand Savings from EE and DR Programs

In this section, we show the peak-demand savings from EE and DR programs. We also show the affect of those savings on the peak demand forecast.

Table 4-16 shows the peak-demand savings from EE and DR programs for each of the scenarios. The S4 Ultra Green scenario achieves the most peak demand savings due to the effect of RPS, carbon cap legislation, smart grid and extremely high electricity prices. Table 4-17 shows the effect the changes to the key assumptions have on the peak demand savings from EE programs only and Table 4-18 shows the effect from DR programs only.

Table 4-16 Peak Demand Savings from EE and DR Programs by Scenario (MW)

	2010	2015	2020	2025	2030
Reference Case	20,537	57,452	82,029	90,924	96,764
S2 RPS	28,084	50,169	59,199	63,891	68,477
S10 Carbon Cap	18,285	38,055	50,412	52,619	55,127
S1 High Growth	17,613	37,253	47,797	51,300	55,120
S4 Ultra Green	37,323	91,656	124,580	130,611	135,451

Table 4-17 Peak Demand Savings from EE Programs Only by Scenario (MW)

	2010	2015	2020	2025	2030
Reference Case	1,953	21,936	39,630	45,567	48,200
S2 RPS	2,064	23,878	43,807	50,715	53,868
S10 Carbon Cap	2,102	24,457	45,052	52,252	55,551
S1 High Growth	1,948	23,161	43,326	50,568	53,858
S4 Ultra Green	2,102	25,141	47,170	55,160	58,876

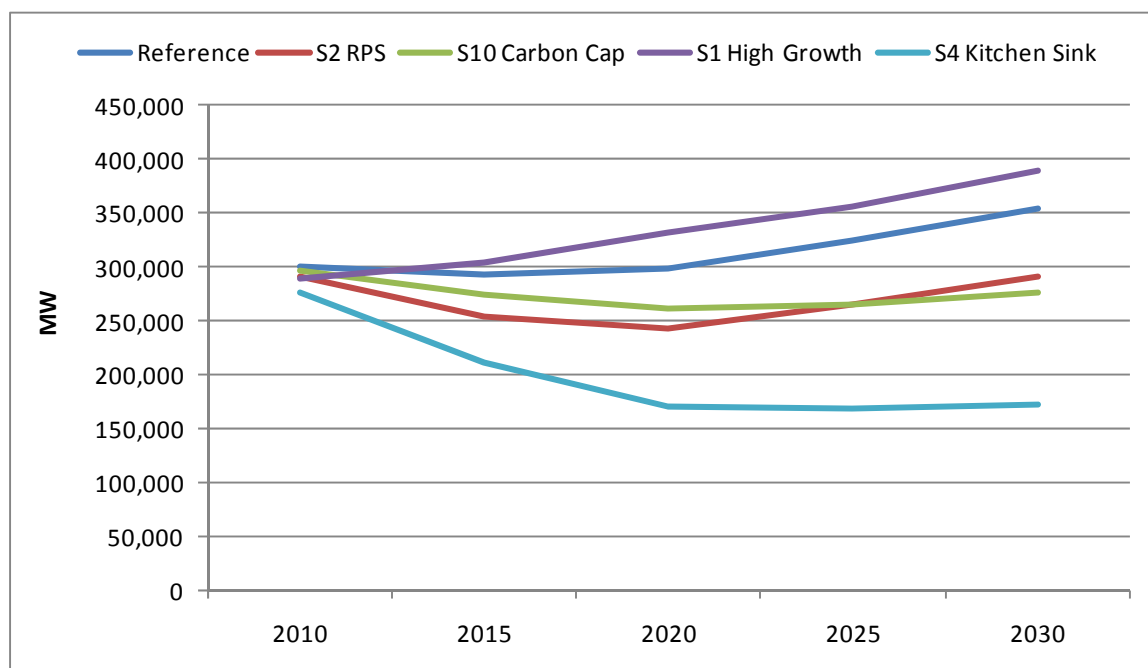
Table 4-18 Peak Demand Savings from DR Programs Only by Scenario (MW)

	2010	2015	2020	2025	2030
Reference Case	18,584	35,517	42,399	45,357	48,564
S2 RPS	28,084	50,169	59,199	63,891	68,477
S10 Carbon Cap	18,285	38,055	50,412	52,619	55,127
S1 High Growth	17,613	37,253	47,797	51,300	55,120
S4 Ultra Green	37,323	91,656	124,580	130,611	135,451

Table 4-19 and Figure 4-6 show the peak demand forecast for each scenario after the demand savings from EE and DR programs are applied. With the exception of S1 High Growth, the scenarios result in peak demand forecasts that are below the 2010 peak demand.

Table 4-19 Peak Demand Forecasts after EE and DR Program Savings by Scenario (MW)

	2010	2015	2020	2025	2030	% Increase (2010-30)	Average Annual Growth (%)
Reference	301,156	292,763	299,072	323,900	354,903	17.8%	0.8%
S2 RPS	290,904	254,619	242,954	265,995	292,208	0.4%	0.0%
S10 Carbon Cap	297,548	274,050	261,256	265,603	276,026	-7.2%	-0.4%
S1 High Growth	289,681	304,495	331,612	356,561	388,704	34.2%	1.5%
S4 Ultra Green	276,548	211,887	170,450	169,904	172,029	-37.8%	-2.4%

Figure 4-6 Forecasts of Peak Demand After EE and DR Program Savings

4.4.4 Energy Savings from EE Programs

In this section, we show the energy savings from EE programs. We also show the affect of those savings on the energy forecast.

Table 4-20 shows the effect the changes to the key assumptions have on the energy savings from EE programs for each of the scenarios. The S4 Ultra Green scenario achieves the most energy savings due to the impact of RPS, carbon cap legislation, smart grid and extremely high electricity prices.

Table 4-20 Energy Savings from EE Programs by Scenario (GWh)

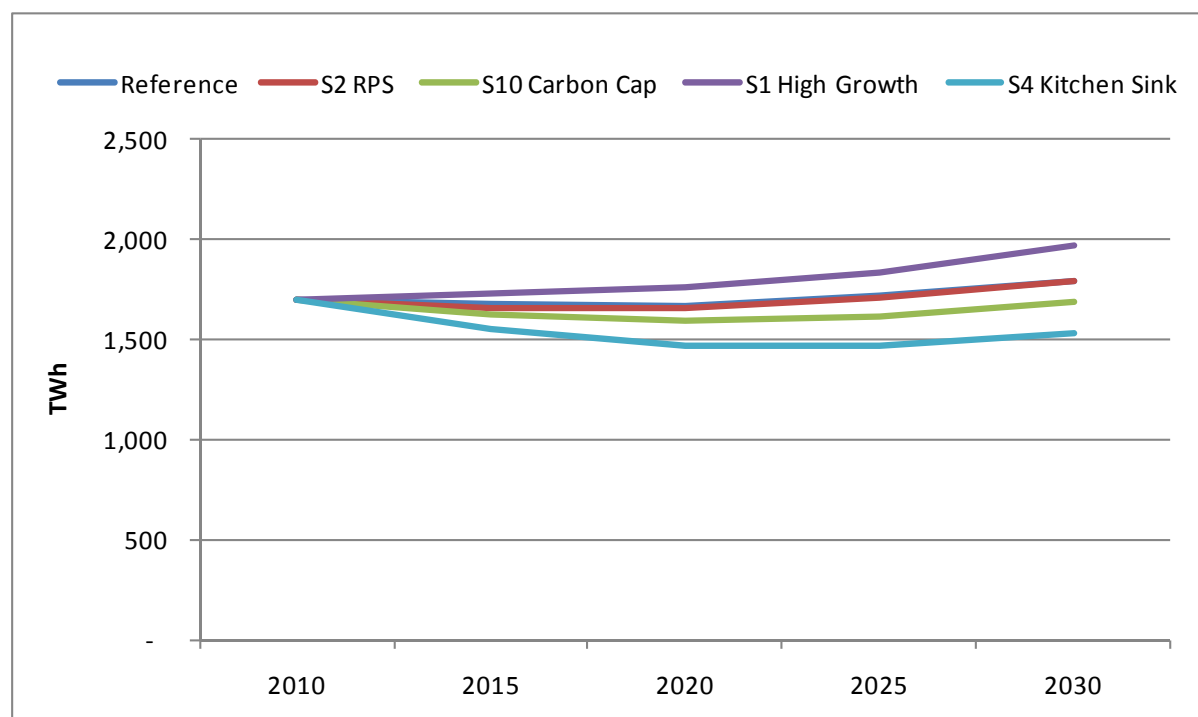
Baseline Demand	2010	2015	2020	2025	2030
Reference	9,948	110,754	202,161	235,603	250,238
S2 RPS	10,422	120,097	222,686	261,462	278,973
S10 Carbon Cap	10,620	123,066	229,183	269,665	288,009
S1 High Growth	9,816	116,670	221,138	261,902	280,217
S4 Ultra Green	10,620	126,556	240,235	285,278	306,000

Table 4-21 and Figure 4-7 shows the energy forecast after the savings from EE programs are applied. Please note that the Reference forecast and the S2 RPS forecasts are nearly the same. The S10 Carbon Cap and S4 Ultra Green scenarios result in declining electricity use for the first ten years of the forecast and then a slight ramping up.

Table 4-21 Energy Forecasts by Scenario (TWh)

	2010	2015	2020	2025	2030	% Increase (2010-30)	Average Annual Growth (%)
Reference	1,696	1,673	1,663	1,716	1,795	5.8%	0.3%
S2 RPS	1,696	1,654	1,652	1,708	1,789	5.5%	0.3%
S10 Carbon Cap	1,695	1,627	1,593	1,619	1,684	-0.7%	0.0%
S1 High Growth	1,696	1,733	1,755	1,838	1,964	15.8%	0.7%
S4 Ultra Green	1,695	1,554	1,470	1,472	1,529	-9.8%	-0.5%

Figure 4-7 Forecasts of Annual Energy Use After EE Program Savings



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