EISPC
EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

Assessment of Demand-Side Resources within the Eastern Interconnection

March 2013

Navigant Consulting, Inc.
For EISPC and NARUC

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ASSESSMENT OF DEMAND-SIDE RESOURCES WITHIN THE EASTERN INTERCONNECTION

prepared for

Eastern Interconnection States' Planning Council

and

National Association of Regulatory Utility Commissioners

prepared by

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Disclaimer

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Executive Summary

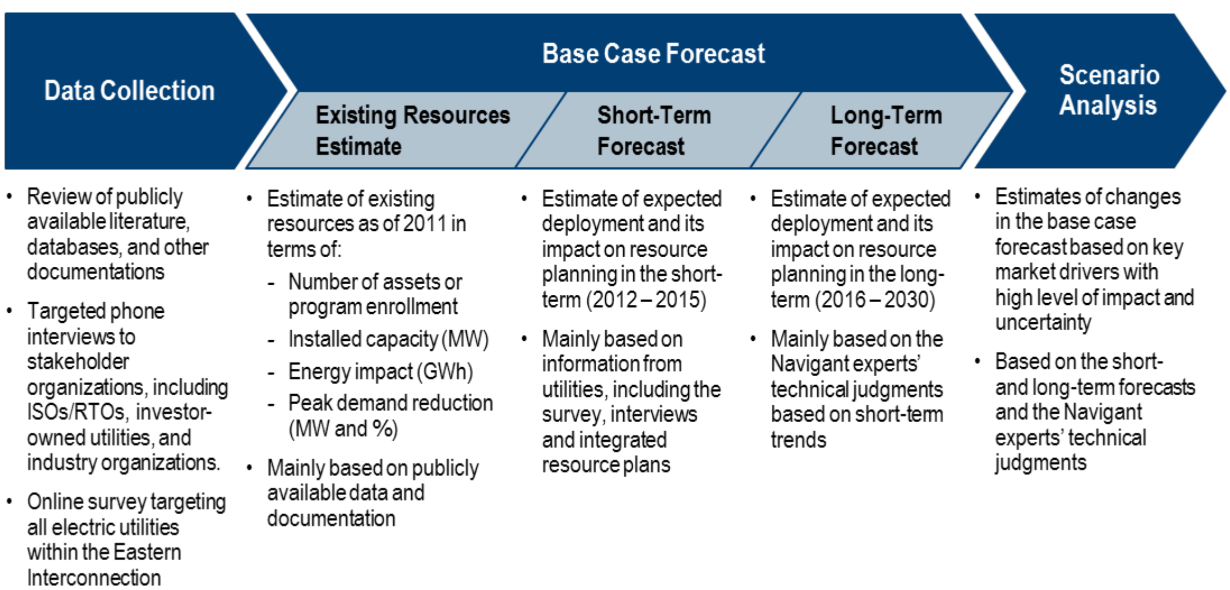
The National Association of Regulatory Utility Commissioners (NARUC) funded this assessment of demand-side resources and their existing and forecasted deployments within the eastern United States. The purpose of this study is to provide NARUC and the Eastern Interconnection States' Planning Council (EISPC) members with a better understanding of the intermediate and long-term demand-side resources that will impact the needs for future transmission development throughout the Eastern Interconnection.

This analysis, which is based upon planned deployment and programs, considers six categories of demand-side resources:

- Study #1: End-use energy efficiency programs (EE),
- Study #2: Demand response programs (DR),
- Study #3: Distributed energy storage systems (ES),
- Study #4: Distributed generation powered by fossil fuels (DG-F),
- Study #5: Distributed renewable resources (DG-R), and
- Whitepaper #1: Other programs and initiatives enabled by the smart grid (SG).

Figure ES-1 presents the key assessment steps this study followed: Data Collection; Base Case Forecast; and Scenario Analysis.

Figure ES-1. Overall Approach for the Demand-Side Resources Assessment



Data Collection

The data collection effort consisted of three steps:

1. The project team identified and reviewed publicly available resources including reports, papers, utility resource plans, and databases.
2. Based on the remaining data gaps, the team conducted targeted phone interviews with organizations such as independent system operators, regional transmission organizations, investor-owned utilities, state energy offices, industry organizations, and Federal agencies such as the Tennessee Valley Authority.
3. Navigant conducted an online survey targeting over 2,300 electric utilities within the Eastern Interconnection to collect the most current forecasts of retail electric sales, customer load, and deployment of demand-side resources. [1]

Table ES-1 summarizes the data sources used for each of the resource categories.

Table ES-1. Summary of Data Sources Referenced in this Study[2]

Data Source	EE	DR	ES	DG-F	DG-R	SG
Utility Survey	✓	✓	✓	✓	✓	✓
Stakeholder Interviews	✓	✓	✓	✓	✓	✓
Utility Integrated Resource Plans[3]	✓	✓		✓	✓	✓
DOE Energy Information Agency Data Files[4]	✓	✓		✓	✓	✓
Consortium for Energy Efficiency Financial Expenditure Data[5]	✓	✓				
ISO/RTO Planning Documents	✓	✓				
Commercial Databases[6]			✓	✓	✓	✓
DOE Office of Electricity Program Data[7]			✓			✓
Sandia Lab Storage Program Data			✓			
American Wind Energy Association Project Data Base					✓	
Edison Electric Institute (EEI) Smart Meter Survey						✓

Base Case Forecast

The "Base Case" forecast of this study represents the expected deployment of demand-side resources based on currently available market information and the continuation of current trends and policies assuming no radical technology changes or breakthroughs. This forecast is based upon planned deployment and programs, and is not an analysis of technical or market potential.

[1] This survey effort was funded independently by NARUC without any government funds.
[2] EE = Energy Efficiency; DR = Demand Response; ES = Energy Storage; DG-F = DG-Fossil; DG-R = DG-Renewables; SG = Smart Grid
[3] The term "Integrated Resource Plan" is used in this report to describe a utility's forward-looking resource plan filed with their state commission. For the purposes of this report, IRP also refers to documents that are not called an IRP (e.g., Florida's Ten-Year Site Plans), but have the same intent as a traditional IRP.
[4] Forms EIA-860 and EIA-861 (2010)
[5] CEE (2011)
[6] Sources include: Energy Acuity; Ventyx Velocity Suite; Navigant/Pike Research; Platt's; and SNL Financial.
[7] Relevant programs include: Smart Grid Investment Grant; Smart Grid Demonstration; Renewables and Distributed Systems Integration; and Energy Storage Systems programs.

The forecast includes three elements:

- **Resource capacity, presented in megawatts (MW)** includes total capacity of energy efficiency and demand response programs, installed capacity of operational distributed generation and energy storage units, and total capacity of time-based rates and conservation voltage reduction programs;[8]
- **Annual energy impact, presented in gigawatt hours per year (GWh/yr)** includes energy savings from EE programs and annual electricity generation from operational DG units; and
- **Peak load impact, presented in megawatts (MW)** of all demand-side resources considered as a result of program execution or technology operation during peak periods.[9]

Based on our forecast, the total resource capacity of demand-side resources will exceed 190,000 MW by 2030. End-use electricity savings, electricity generation from customer-owned generation assets, and reduction in system losses through utility smart grid programs associated with those resources would result in an annual energy impact of nearly 389,000 GWh/yr by 2030, or approximately 13% of the annual electricity consumption within the Eastern Interconnection. Similarly, the total peak load impact of demand-side resources will exceed 140,000 MW by 2030. This translates to nearly 20% of the forecasted peak demand within the Eastern Interconnect region.[10] Table ES-2 presents total peak load impact of demand-side resources by resource category.

Table ES-2. Total Demand-Side Resource Peak Load Impact by Resource Category

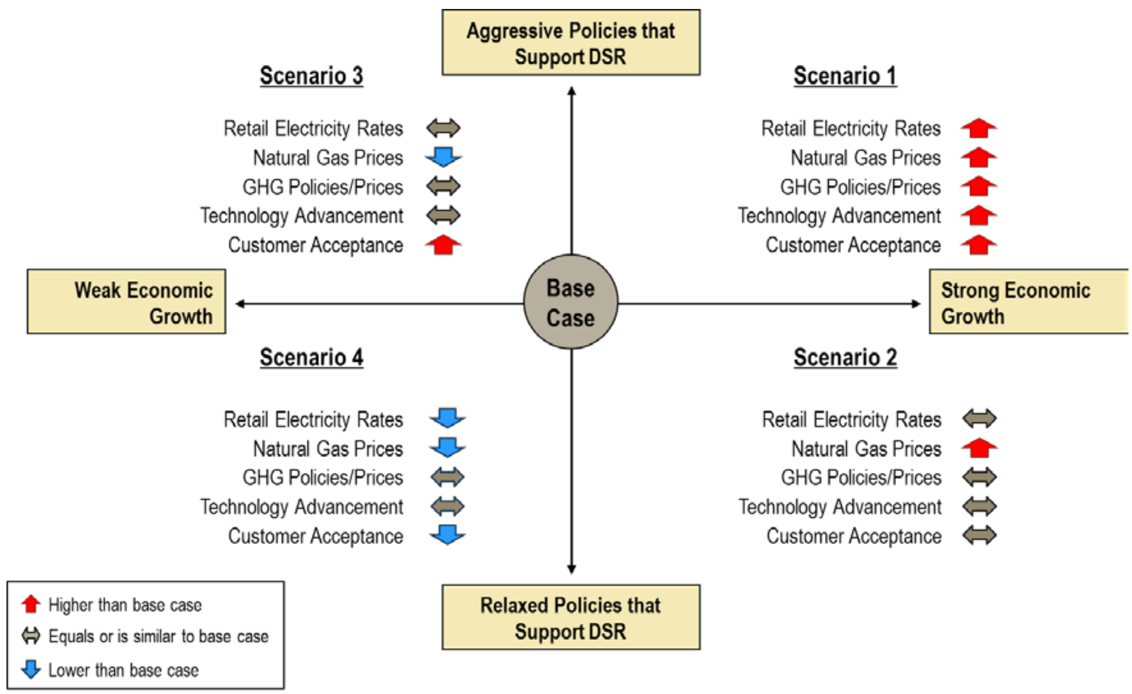
Resource Category		Projected Total Demand-Side Resource Capacity (MW)						
		2012	2013	2014	2015	2020	2025	2030
Energy Efficiency		3,016	5,650	8,567	11,542	25,956	40,106	53,369
Demand Response	*Conventional Programs*	23,514	26,451	31,245	32,005	31,614	32,412	33,415
	*Smart Grid-Enabled**	929	1,032	1,184	1,322	3,230	4,451	5,639
Energy Storage		64	68	76	79	629	1,253	2,040
DG-Fossil		15,740	15,666	15,663	15,625	16,031	16,695	17,671
DG-Renewables		4,198	4,713	5,289	5,972	10,745	17,007	24,516
Smart Grid (CVR)		353	557	612	1,124	1,481	3,276	4,075
TOTAL		48,103	54,424	62,918	67,948	89,950	115,454	140,972
Total Annual Peak Load		*577,087*	*585,752*	*596,594*	*604,471*	*640,249*	*677,684*	*718,217*
% of Peak Load Supported by Demand-Side Resources		8.3%	9.3%	10.5%	11.2%	14.0%	17.0%	19.6%
** Includes time-based rate programs that require AMI meters with two-way communication capability.*								

[8] It is common practice in resource planning to account for operating reserve to provide for regulation, load forecasting error, equipment-forced and scheduled outages, and local area protection. The estimated resource capacities included in this assessment have not been adjusted to include a reserve margin.
[9] This study compares the results of the demand-side resource forecast against annual peak load, which may occur in different seasons for different states.
[10] "Total peak demand" is the sum of non-coincident peak based on NERC forecast of peak demand for assessment areas from 2012 Long-Term Reliability Assessment.

Scenario Analysis

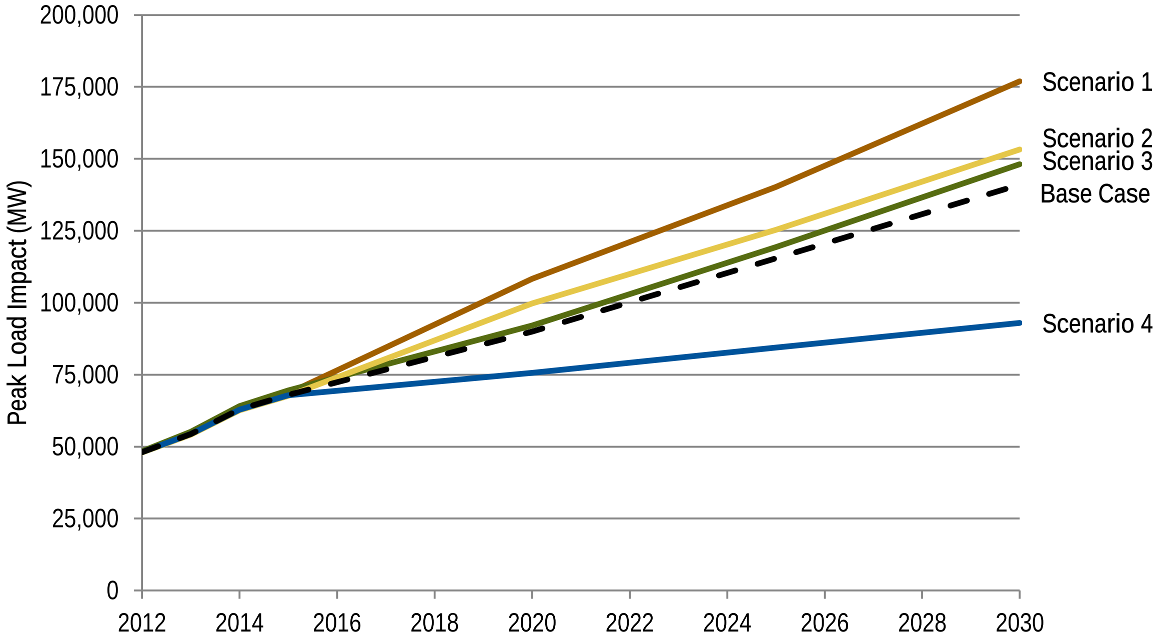
The final step of this analysis was a scenario analysis intended to address changes in forecasts related to seven market drivers with high levels of impact and uncertainty. The four scenarios depict alternative paths of demand-side resource adoption based on different trajectories of the two key drivers: aggressive versus relaxed goals pertaining to policies that support demand-side resources; and strong versus weak economic growth. The team further defined these scenarios in terms of how the five secondary drivers may behave in each instance. Figure ES-2 presents how the team defined each scenario relative to the Base Case.

Figure ES-2. Scenario Analysis Approach Based on the Market Drivers Affecting Adoption of Demand-Side Resources



Among the four scenarios, Scenario 1 has the largest total peak load impact. Aggressive policy goals coupled with penalties on greenhouse gas emissions lead to a significant increase in adoption of EE, DR, and DG-R, resulting in a nearly 26% increase in peak load impact relative to the Base Case. Conversely, Scenario 4 has the smallest total peak load impact. In the absence of supporting policies, low retail electricity prices lead to resistance to new investments aimed at reducing peak demand. Figure ES-3 presents the forecast of demand-side resource peak load impact through 2030 for the Base Case and four scenarios.

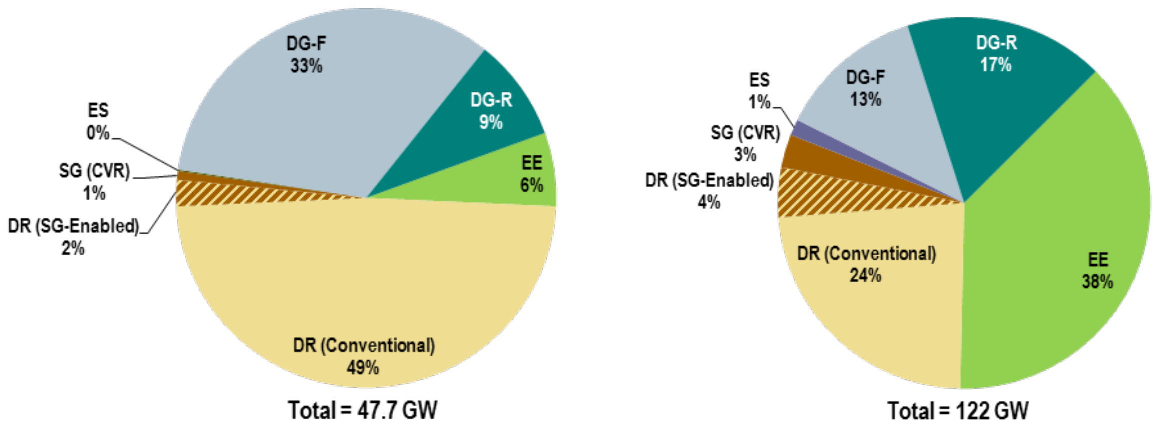
Figure ES-3. Scenario Analysis of Demand-Side Resources Peak Load Impact through 2030



Observations

As Table ES-2 indicates, the demand-side resources will continue to grow steadily through 2030 and will support nearly 20% of the forecasted annual peak load by 2030. Based on the result of the forecast, several additional key observations emerge. First, demand-side management programs will continue to grow as the largest contributor towards the overall peak load impact of demand-side resources. As Figure ES-4 indicates, energy efficiency programs and demand response programs (both conventional and smart grid-enabled programs) account for 57% of the total peak load impact from demand-side resources in 2012. This percentage will grow to 66% in 2030, mainly as a result of sustained long-term growth of energy efficiency programs.

Figure ES-4. Estimated Ratio of Demand-Side Resource Peak Load Impact in 2012 (Left) and 2030 (Right), by Resource Category



Second, resource categories supported by emerging technologies will exhibit the strongest growth. The total peak load impact of smart grid-enabled time-based rate programs, advanced utility CVR programs, and energy storage will increase by a factor of 6 between 2012 and 2030. This rate of growth is over three times as fast as that of conventional DSM programs.

Third, energy policies and retail electricity prices are the two market drivers likely to have the strongest influence on the growth in adoption of demand-side resources. In Scenario 1 (with strong economic growth and aggressive policy goals), policies that encourage implementation of DSM program and penalties on greenhouse gas emissions provides significant boost to the forecasted adoption of EE, DR and DG-R, resulting in nearly 26% increase in peak load impact relative to the Base Case. In contrast, in Scenario 4 (with weak economic growth and relaxed energy policy goals), the absence of supporting policies paired with the low retail electricity prices leads to resistance to new investments in utility DSM programs and DG-R.

1. Introduction

The National Association of Regulatory Utility Commissioners (NARUC) is a non-profit organization dedicated to representing the state public service commissions who regulate the utilities that provide essential services such as energy, telecommunications, water, and transportation. NARUC's mission is to serve the public interest by improving the quality and effectiveness of public utility regulation. Its members include all 50 states, the District of Columbia, the City of New Orleans, Puerto Rico, and the Virgin Islands.

NARUC serves as the umbrella organization for the Eastern Interconnection States' Planning Council (EISPC), a collaboration of the 39 eastern states[11], the City of New Orleans, and the District of Columbia, to support the coordinated involvement of member entities for region-wide planning efforts. This endeavor to institute a more coherent and comprehensive approach to planning for long-term electric power needs is supported by funding from the United States Department of Energy (DOE) pursuant to a provision of the American Recovery and Reinvestment Act (ARRA).

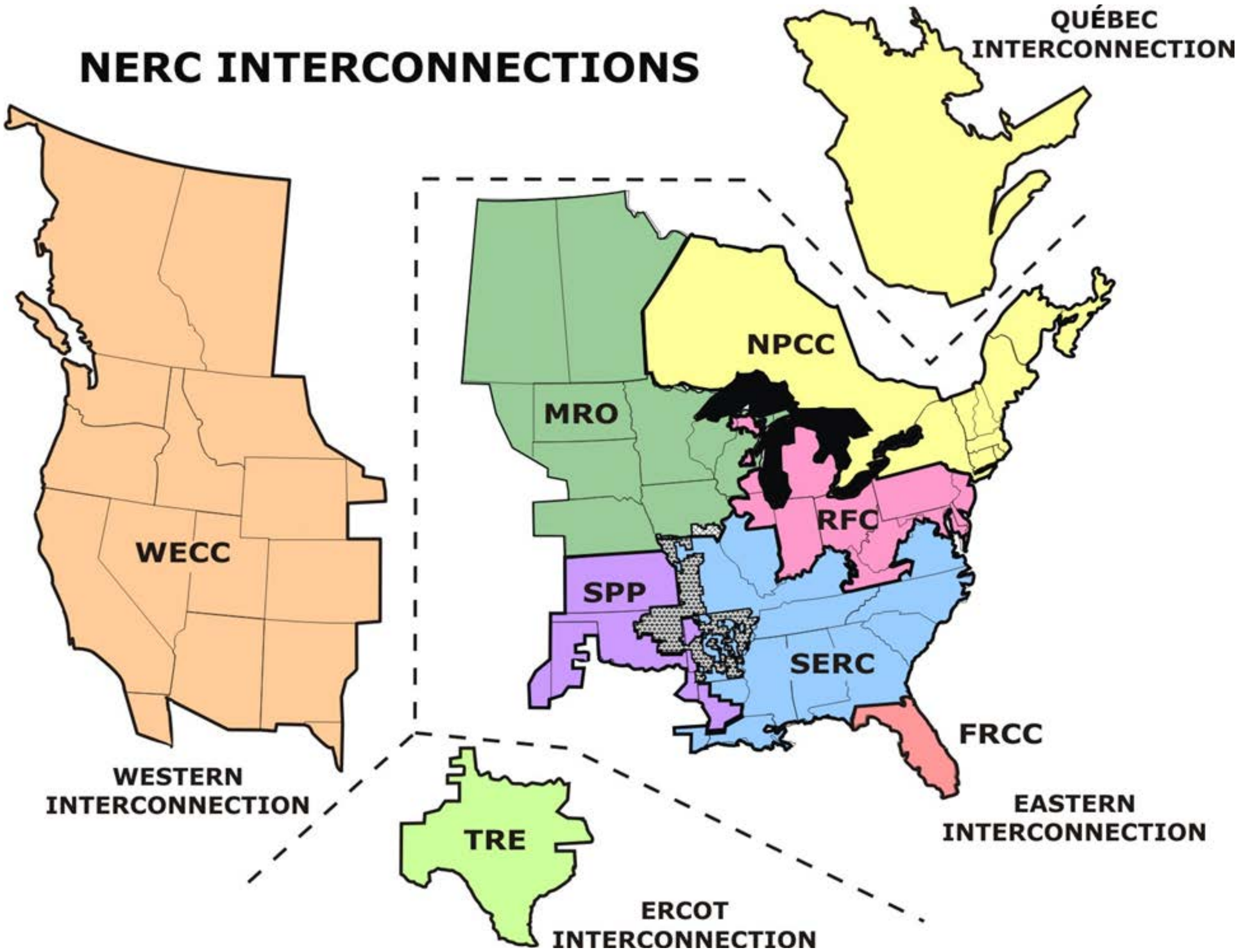
All members of EISPC are served by the Eastern Interconnection. The six North American Electric Reliability Corporation (NERC) regional reliability entities that comprise that territory are:

- Florida Reliability Coordination Council (FRCC)
- Midwest Reliability Organization (MRO)
- Northeast Power Coordinating Council (NPCC)
- ReliabilityFirst Corporation (RFC)
- SERC Reliability Corporation
- Southwest Power Pool (CPP)

Figure 1-1 presents the map of interconnections and NERC regional reliability entities.

[11] Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Vermont, Virginia, West Virginia, and Wisconsin

Figure 1-1. NERC Interconnections



The electric utility industry is entering a new phase where the innovations associated with many advanced technologies are converging to create new opportunities that will impact long-term planning. These advances include: smart grid; new cost-competitive distributed power generation and energy storage technologies; increased applications of communications and information technologies to the electricity sector; increases in end-use energy efficiency; and more widespread use of direct load control and demand response. The implications associated with the convergence of these technologies are not fully understood in terms of their effects on the transmission system, reliability, and long-term resource requirements. Thus, EISPC members are interested in the likely impact of these technologies and resources on regional transmission system planning.

The purpose of this study is to provide EISPC members with a better understanding of the intermediate and long-term resources that will impact the needs for future transmission development throughout the Eastern Interconnection. The information from this analysis will also inform future analyses that EISPC members may conduct.

2. Scope and Approach

2.1 Scope

The objective of this analysis was to assess the existing and forecasted deployment of demand-side resources in the 41 U.S. entities (39 U.S. states, New Orleans, and the District of Columbia) that comprise the Eastern Interconnection. The study considers six categories of demand-side resources: Energy Efficiency (EE), Demand Response (DR), Distributed Energy Storage (ES), Distributed Fossil Fuel Resources (DG-F), Distributed Renewable Resources (DG-R), and Smart Grid (SG). This study was based on planned deployment and programs, and was not an analysis of technical or market potential.

Table 2-1 presents the definitions of the six resource categories used in this study.

Table 2-1. Categories and Definitions of Demand-Side Resources

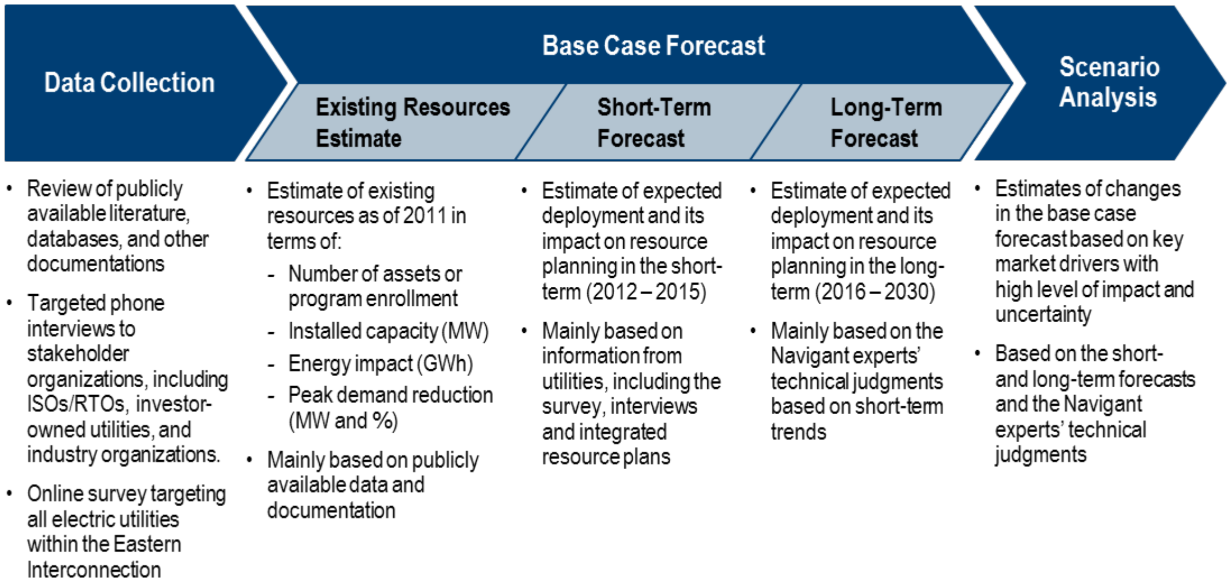
Resource Category	Definition
Energy Efficiency (EE)	End-use energy efficiency programs facilitated by utility and state policy programs, excluding initiatives related to demand response, smart grid, and distributed generation.
Demand Response (DR)	Incentive-based programs for customers to curtail loads during peak times, including direct load control, load curtailment rate classes, and aggregator-provided commercial and industrial DR. Does not include programs that require two-way communication and advanced metering infrastructure (AMI).
Distributed Energy Storage (ES)	Storage systems (1 MW and larger) used for peak load impact, time-shifting, renewables integration and frequency regulation. Includes batteries, flow batteries, and fly wheels.
Distributed Fossil Fuel Resources (DG-F)	Customer- and utility-sited gas, oil, and coal resources with nameplate capacity between 1 MW and 20 MW.
Distributed Renewable Resources (DG-R)	Customer- and utility-sited solar photovoltaics (PV), wind, biomass, and hydro resources under 10 MW.
Smart Grid (SG)	Programs enabled by AMI meters, two-way communications, or distribution automation, including time-based rates such as critical peak pricing (CPP), time-of-use (TOU), critical peak rebates (CPR), real time pricing (RTP), and variable peak pricing (VPP), as well as conservation voltage reduction (CVR).

Refer to the corresponding part in Section 3 for more precise definitions of these resource categories.

2.2 Approach

This study included three key steps: Data Collection, Base Case Forecast, and Scenario Analysis. Figure 2-1 summarizes each of the assessment steps.

Figure 2-1. Breakdown of Assessment Steps



2.2.1 Data Collection

The data collection consisted of three steps:

- First, the Navigant project team (Navigant) identified and reviewed publicly available resources including reports, papers, utility resource plans, and databases.
- Second, based on the remaining data gaps, the team conducted targeted phone interviews. Interviewed organizations include: independent system operators and regional transmission organizations (ISOs/RTOs); investor-owned utilities (IOUs); state energy offices; industry organizations; and Federal agencies such as the Tennessee Valley Authority.
- Third, Navigant conducted an online survey targeting over 2,300 electric utilities within the Eastern Interconnection. This survey was designed to collect the most current forecasts of retail electric sales, customer load, and deployment of demand-side resources. [12]

Table 2-2 summarizes the data sources used for each of the relevant resource categories. For the complete set of citations for data sources and other publicly available reports and articles that do not fall into the following categories, refer to Section 6.

[12] This survey effort was funded independently by NARUC without any government funds.

Table 2-2. Summary of Data Sources Referenced in this Study

Data Source Category	EE	DR	ES	DG-F	DG-R	SG
Utility Survey	✓	✓	✓	✓	✓	✓
Stakeholder Interviews	✓	✓	✓	✓	✓	✓
Utility Integrated Resource Plans (IRPs)[13]	✓	✓		✓	✓	✓
DOE Energy Information Agency (EIA) Data Files[14]	✓	✓		✓	✓	✓
Consortium for Energy Efficiency (CEE) Financial Expenditure Data[15]	✓	✓				
ISO/RTO Planning Documents	✓	✓				
Commercial Databases[16]			✓	✓	✓	✓
DOE Office of Electricity (OE) Program Data[17]			✓			✓
Sandia Lab Storage Program Data			✓			
American Wind Energy Association (AWEA) Project Data Base					✓	
Edison Electric Institute (EEI) Smart Meter Survey						✓
Other Publicly Available Reports and Articles	✓	✓	✓	✓	✓	✓

2.2.2 Base Case Forecast

The "Base Case" forecast of this study represents the expected deployment of demand-side resources based on the available market information and the continuation of current trends and policies assuming no radical technology changes or breakthroughs. It should be noted that the goal of this analysis was not to evaluate the potential of demand-side resources adoption, but to use current activity and commitment to provide a reasonable outlook on their adoption and impact on regional- and state-level transmission planning.

The Base Case forecast includes estimates for existing resources[18], as well as short-term expected deployment through 2015 and long-term forecasted deployment through 2030. The existing resource estimate and short-term forecast, which represent committed programs and continuation of 2012 market activity, are predominantly based on information from utilities and industry organizations, including project databases and integrated resource plans. The long-term forecast is based on the interpretation of short-term trends by the project team and other Navigant subject matter experts.

The forecast includes three elements:

[13] The term "Integrated Resource Plan" is used in this report to describe a utility's forward-looking resource plan filed with their state commission. For the purposes of this report, IRP also refers to documents that are not called an IRP (e.g., Florida's Ten-Year Site Plans), but have the same intent as a traditional IRP.
[14] Forms EIA-860 and EIA-861 (2010)
[15] CEE (2011)
[16] Sources include: Energy Acuity; Ventyx Velocity Suite; Navigant/Pike Research; Platts; and SNL Financial.
[17] Relevant programs include: Smart Grid Investment Grant; Smart Grid Demonstration; Renewables and Distributed Systems Integration; and Energy Storage Systems programs.
[18] Based on 2010 data for AMI meters, 2012 data for EE and DR programs, and 2011 for all other resource categories.

- **Resource capacity (MW)** includes total capacity of EE and DR programs, installed capacity of operational distributed generation (DG) and energy storage units, and total capacity of time-based rates and CVR programs;[19]
- **Annual energy impact (GWh/yr)** includes energy savings from EE programs, and annual electricity generation from operational DG units; and
- **Peak load impact (MW)** of all demand-side resources considered as a result of program execution or technology operation during peak periods.[20]

Section 3 presents a more detailed discussion of the forecast results for each resource category and Appendix A presents the forecast results differentiated by the 41 EISPC entities.

2.2.3 Scenario Analysis

The final step of this study was a scenario analysis intended to address changes in forecasts that could occur due to fluctuations in key market drivers with high levels of impact and uncertainty. Table 2-3 presents the seven market drivers that the team deemed most influential to future adoption of demand-side resources.

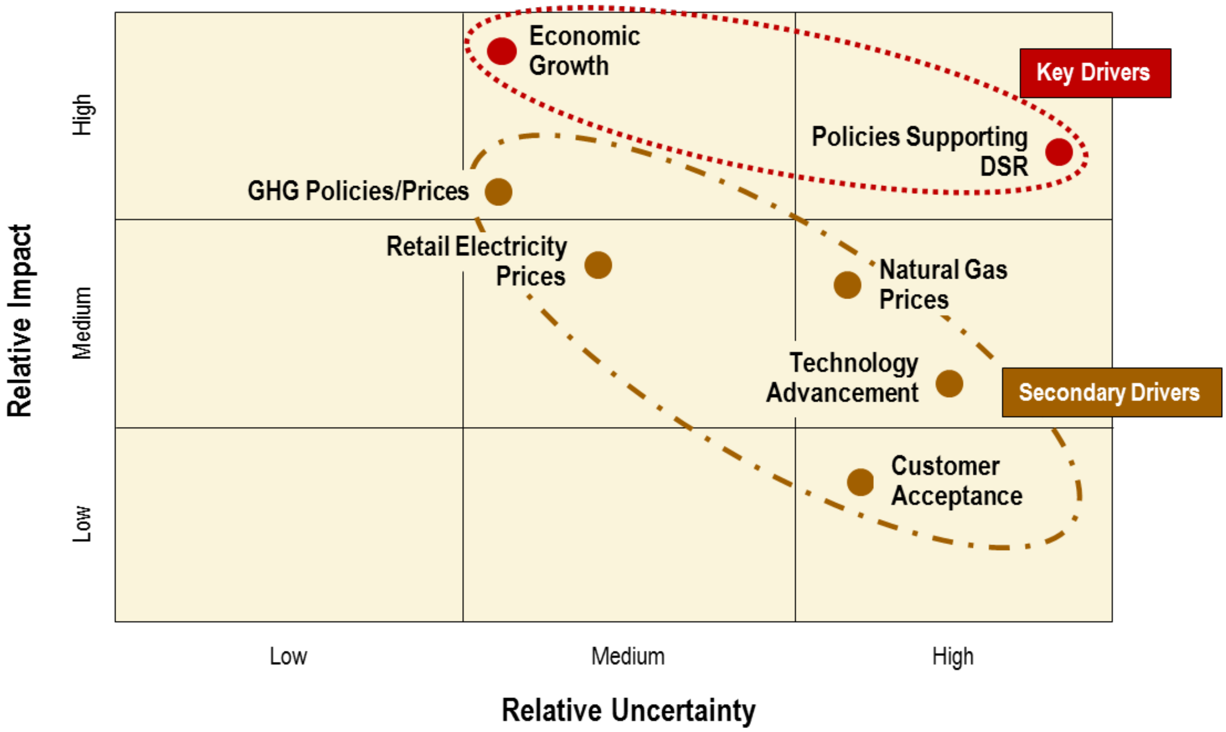
Table 2-3. Scope of the Scenario Drivers

Scenario Driver	Scope
Policies Supporting Demand-Side Resources (DSR)	Policies that may promote, incentivize, or mandate increased adoption of demand-side resources, including: • Renewable Portfolio Standards • Energy Efficiency Resource Standards • Adoption Targets for smart meters/time-based rate programs.
Economic Growth	Annual rate of U.S. domestic GDP growth.
Retail Electricity Price	Average retail price of electricity across residential, commercial, and industrial customers.
Natural Gas Prices	Market trend of natural gas, in terms of average retail price across residential, commercial, and industrial customers, as well as the Henry Hub price.
Greenhouse Gas (GHG) Policies/Prices	Federal or state-level policies on reduction of greenhouse gas emissions or emissions intensity as it pertains to the electricity sector (e.g., impact on generation mix and retail electricity prices).
Technology Advancement	The level of RD&D/commercialization activities for technologies that results in significant reduction in cost, increase in adoption, and/or enhancement in performance of the demand-side resources.
Customer Acceptance	The level of customer acceptance of demand-side resources.

Of these seven drivers, Navigant identified both economic growth and energy policies that support demand-side resources as the two with the highest potential impact and most uncertainty for demand-side resources. Figure 2-2 presents the scenario drivers arranged according to their relative impact and uncertainty.

[19] It is common practice in resource planning to account for operating reserve to provide for regulation, load forecasting error, equipment-forced and scheduled outages, and local area protection. The estimated resource capacities included in this assessment have not been adjusted to include a reserve margin.
[20] This study compares the results of the demand-side resource forecast against annual peak load, which may occur in different seasons for different states.

Figure 2-2. Evaluation of Market Drivers Affecting Adoption of Demand-Side Resources



The team developed four scenarios that depict different paths of demand-side resources adoption based on different trajectories of the two key drivers: aggressive versus relaxed goals pertaining to policies that support demand-side resources; and strong versus weak economic growth. Table 2-4 describes the four adoption scenarios.

Table 2-4. Definition of Adoption Scenarios

Scenario	Descriptions
Scenario 1 (Stronger economic growth and more aggressive energy policy targets relative to the Base Case)	Under this scenario, both the Federal and state governments pursue more aggressive energy policy targets relative to the Base Case. Public support for actions against climate change culminates in a regulation that applies a penalty for greenhouse gas (GHG) emissions. These factors, combined with strong and sustained economic growth, result in a continuous rise in energy prices at a faster pace than that of the Base Case. Breakthroughs in advancements of enabling and supporting technologies, as well as widespread customer acceptance of advanced energy management solutions further fuel the increased adoption of demand-side resources.
Scenario 2 (Stronger economic growth and more relaxed energy policy targets relative to the Base Case)	Similar to Scenario 1, this scenario assumes a stronger economic growth relative to the Base Case is sustained through 2030. However, setting policy goals in the areas of renewables, energy efficiency, or greenhouse gas is not a high priority, resulting in a more relaxed set of pertinent policy goals relative to the Base Case. Therefore, the energy prices will remain largely equal to those of the Base Case; although, a strong economy is typically associated with increase in energy prices.
Scenario 3 (Slower economic growth and more aggressive energy policy targets relative to the Base Case)	Similar to Scenario 1, in this scenario government agencies pursue more aggressive energy policy targets relative to the Base Case. However, with slower economic growth relative to the Base Case, the economy is not able to support drastic policy changes such as GHG emissions regulations. As such, relevant government bodies do not expand their policymaking efforts beyond the areas of renewables and energy efficiency resources. Under this economic and policy environment, demand-side resources are widely accepted among its stakeholders as a sensible way to save costs and resources.
Scenario 4 (Slower economic growth and more relaxed energy policy targets relative to the Base Case)	Similar to Scenario 3, this scenario assumes a more stagnant economic development relative to the Base Case. Furthermore, setting policy goals in the areas of renewables, energy efficiency, or greenhouse gas is not a high priority, resulting in more relaxed set of pertinent policy goals relative to the Base Case. Stakeholders are not given any incentive increase adoption of demand-side resources, and utility customers continue to push back on enabling technologies due to documented and perceived concerns.

These four scenarios also reflect the impact of the five secondary drivers. Figure 2-3 presents how the secondary drivers may behave relative to the Base Case in each of the scenarios.

Figure 2-3. Evaluation of Market Drivers Affecting Adoption of Demand-Side Resources

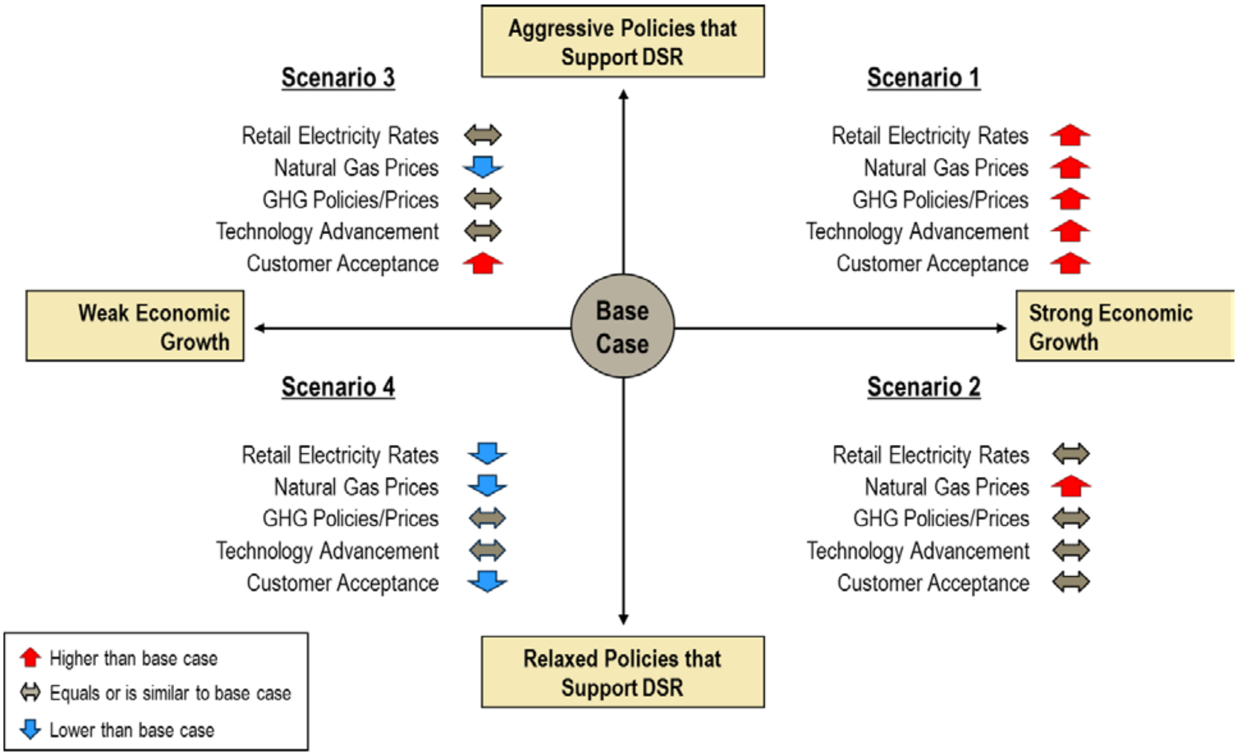


Table 2-5 summarizes the assumptions regarding each driver for the four scenarios as well as the Base Case.

Table 2-5. State of Scenario Drivers for Each Adoption Scenario

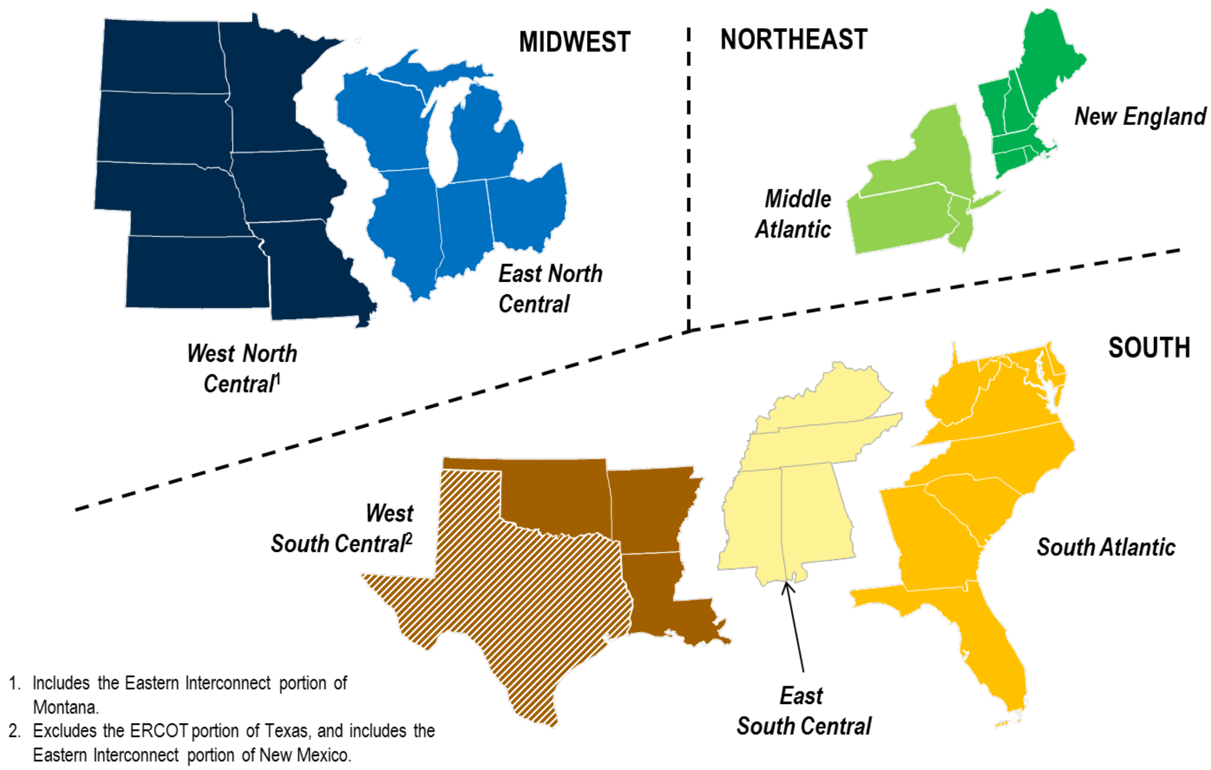
Scenario Driver		Base Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Policies Supporting DSR		Develops at the expected rate	Federal and state agencies pursue aggressive goals	Fed. and state agencies relax policy goals	= Scenario 1	= Scenario 2
Economic Growth		Rate of GDP growth = 2.5%/yr	Rate of GDP Growth = 3%/yr		Rate of GDP Growth = 2%/yr	
Retail Elec. Price		Remains at the 2012 level in real dollars through 2030	35% above the Base Case by 2030	Same as the Base Case		5% below the Base Case by 2030
NG Prices	*Retail*	Avg. rate of change = 1.5%/yr in real dollars	40% above the Base Case by 2030	Same as the Base Case		5% below the Base Case by 2030
	Henry Hub	Avg. rate of change = 3%/yr in real dollars	25% above the Base Case by 2030	5% above the Base Case by 2030	5% below the Base Case by 2030	10% below the Base Case by 2030
GHG Policies/ Prices		No viable emissions regulation mechanisms or pricing schemes established before 2030	Some market or regulatory mechanism in place by 2030 that results in an emissions penalty equivalent to $25/ton of CO_2 equivalent	Same as the Base Case		
Technology Advancement		No significant breakthroughs	Breakthroughs that brings about meaningful impact on DSR by 2030.	Same as the Base Case		
Customer Acceptance		Increases at the expected rate	DSR accepted as a norm	Same as the Base Case	DSR accepted as a norm	Customers continue to push back

See Appendix B for more precise descriptions of each scenario and the bases of these assumptions.

3. Approach and Results by Resource Category

The following subsections present the data used, assumptions, and forecast results for each resource category. In these sections, the project team chose to aggregate the data by U.S. Census Region and Division for ease of reading and because their boundaries coincide with state borders. Figure 3-1 presents the three Census Regions and the seven Census Divisions within the Eastern Interconnection.

Figure 3-1. U.S. Census Regions and Divisions[21]



Refer to Appendix A for state-by-state breakdowns of the forecast results.

3.1 Study #1: Energy Efficiency

Navigant forecasted the penetration of existing and planned energy efficiency (EE) within the Eastern Interconnection with attention to the following dimensions:

- State,

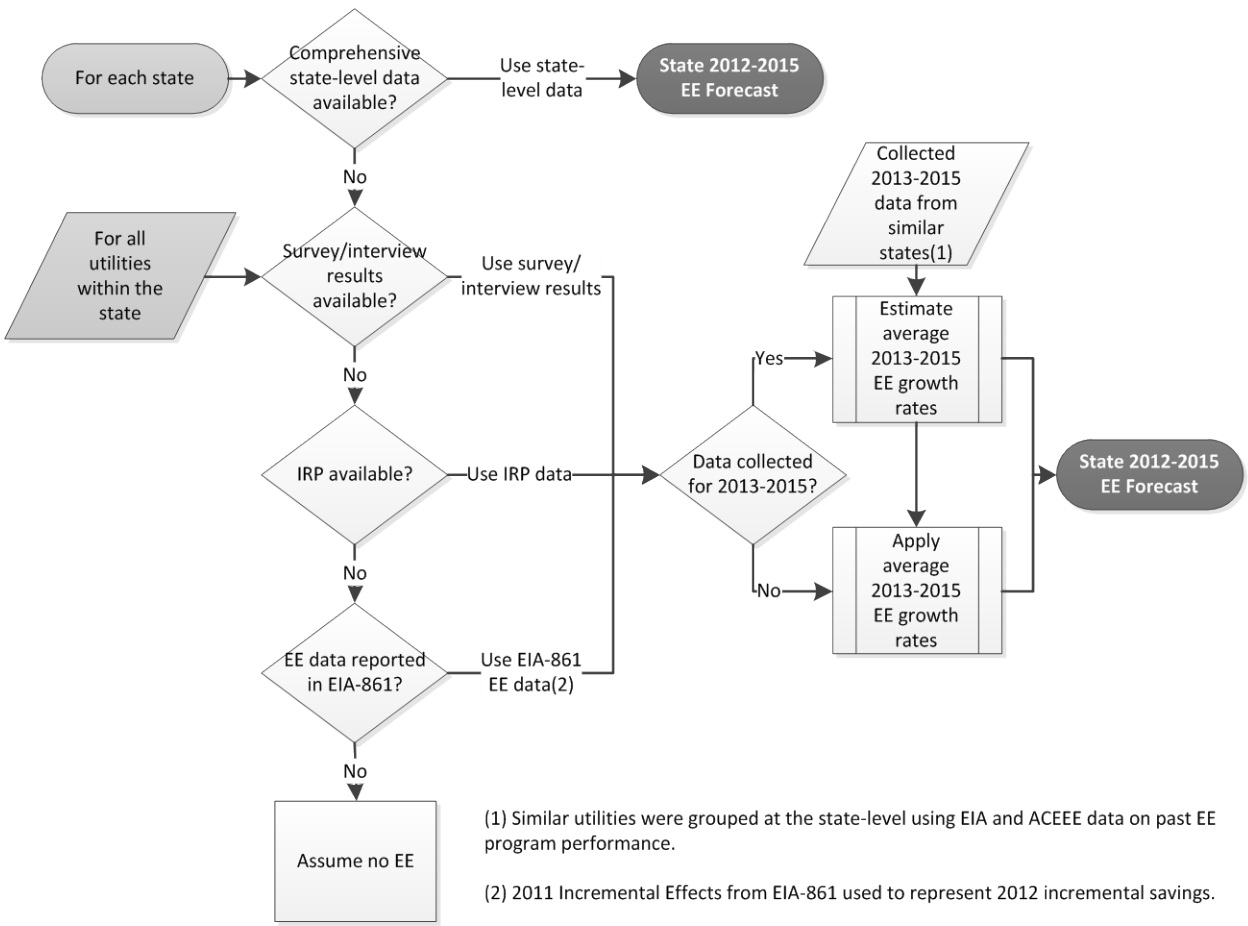
[21] This figure presents the boundaries of Census regions and division, and not necessarily the way this report aggregates the forecast results. For instance, this study does not include the ERCOT portion of Texas, but does include the Eastern Interconnect portion of both Montana and New Mexico. Although Montana and New Mexico are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.

- Savings incremental to 2011 (i.e., new savings from existing resources, as well as projected savings from EE resources that are new in 2012 or after), and
- Customer segment (i.e., Residential, C&I).

The EE in this report considers programmatic savings, but does not explicitly consider savings from codes and standards because it was outside the scope of this analysis to quantify these impacts and it was assumed these savings were accounted for either within a utility's load forecast or at the national level. However, if apparent and applicable, the project team did remove savings attributable to codes and standards.

This analysis represents a bottom-up forecast based on aggregated, publicly-available data and a limited number of confidential sources. To synthesize the various data sources, the project team compiled the collected data in a model built in SAS® analytics software, and applied the normalization and analysis steps shown in Figure 3-2 so that aggregation could occur meaningfully and accurately. Sections 3.1.1 and 3.1.2 describe the data sources, assumptions, and forecasting approach in more detail.

Figure 3-2. Overview of Analysis Methodology and Data Sources



3.1.1 Sources and Data Collection

The primary sources of data used for the EE analysis are utility integrated resource plans (IRPs).[22] While not all states in the Eastern Interconnection require utilities to file an IRP, roughly three-quarters of the states do require utilities to file an IRP or some other type of long-term plan. These IRPs typically contain forecasts of existing and planned load, energy, EE, and DR for the utility and sometimes contain information about customer segments and program types. Navigant collected data from over 70 IRPs in 29 states, which represent about 75% of the states in the Eastern Interconnection.

Navigant used both primary and secondary sources to augment the IRP data and fill in gaps where utilities were not required to file an IRP or filed an IRP that was confidential or out-of-date. One of the key sources used was the Energy Information Administration (EIA)'s Annual Electric Power Industry Report (Form EIA-861), which collects data from utilities on their existing demand-side management programs. Navigant also used utility-level data collected through surveys; spoke to utilities, ISO/RTOs, and commission staff; reviewed state-level data from other sources, including statewide EE programs; and benchmarked results against CEE's 2012 Annual Industry Report and ACEEE's 2012 State Energy Efficiency Scorecard. For a complete list of sources reviewed and used, please see Section 6.

In addition to the annual energy and peak load impacts each year, Navigant also collected available information on whether the resource was incremental or cumulative, committed or planned, net or gross, and other characteristics as discussed in Section 3.1.2.

3.1.2 Analysis Approach

The goal of this analysis is to forecast the adoption of demand-side resources, such as EE, and the associated impact on electricity demand in terms of three factors: resource capacity; annual energy impact; and peak load impact. In the context of the EE forecast, these factors are defined as follows:

- **Resource capacity** refers to the estimated reduction in gross electricity generation capacity required to meet annual peak demand within the Eastern Interconnection as a result of reduced end-use energy consumption;
- **Annual energy impact** refers to the estimated reduction in gross annual electricity generation within the Eastern Interconnection as a result of reduced end-use energy consumption from state and utility programmatic efforts. The annual energy impacts are presented as the incremental EE savings to 2011 cumulated for each following year such that the impact is zero in 2011 and the sum of all incrementally added EE in each subsequent year; and
- **Peak load impact** is considered the same as resource capacity for EE in this analysis.

Using available resources, Navigant made every effort possible to understand whether the annual energy and peak load impacts from EE were already included in a utility's load forecast and to only forecast incremental EE. Unfortunately, this information was not always available, thus the EE impacts presented in this analysis likely include some EE that has already been accounted for in utility forecasts.

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[22] The term "Integrated Resource Plan" is used in this report to describe a utility's forward-looking resource plan filed with their state commission. For the purposes of this report, IRP also refers to documents that are not called an IRP (e.g., Florida's Ten-Year Site Plans or Maryland's Energy Efficiency and Conservation Plans), but have the same intent as an IRP.

As described above, it was not within the scope of this analysis to quantify the impacts of codes and standards and it was assumed the corresponding savings were accounted for either within a utility's load forecast or at the national level. However, the project team did remove savings attributable to codes and standards, if apparent and applicable.

Considerations and Identified Issues

As each source used its own set of assumptions and dimensions to forecast and characterize EE savings, Navigant took a number of steps to normalize the collected data and make it consistent for aggregation. Key steps and assumptions include the following:

1) Ensuring that EE savings were reported as savings accrued incrementally after 2011 rather than total cumulative savings was the most significant challenge associated with the EE analysis. Reporting incremental savings is important because many utilities have incorporated established EE savings into their long-term load and energy forecasts, making it difficult to report total EE savings on a truly cumulative basis. Analytical issues occurred when either it was unclear whether the data were incremental or cumulative or if the data was cumulative and unavailable for either 2011 or 2012. In these cases, Navigant cross-checked data with other available sources to make a best-guess estimate.
2) Some utilities presented combined forecasts of EE and DR. To estimate the savings from EE versus DR in these cases, Navigant looked at the ratio of EE to DR savings for utilities across all the states that reported both types separately and found that, on average, 80% of a utility's EE/DR resource capacity came from DR savings and 20% came from EE savings, while virtually all of the utility's EE/DR annual energy impacts came from EE. These average ratios of EE to DR for resource capacity and annual energy impacts were then applied to forecasts with EE and DR combined.
3) For some utilities, peak demand impact was unavailable, so Navigant estimated the peak demand impact from the reported EE annual energy impact. To do so, Navigant found the average ratio of annual energy impact to peak demand impact for the EE programs of utilities that reported both types separately. This average ratio was then applied to EE annual energy impact forecasts to estimate a peak demand impact.
4) Winter and summer peak demand impacts were not distinguished within the analysis results because insufficient data were available to assess them individually. If both winter and summer peak demand impacts were available for an entity, the maximum was used.
5) Many utilities with service territories spanning more than one state did not report savings separately for each state. In these cases, Navigant used the ratio of utility-reported bundled-delivered energy in each state to the total bundled-delivered energy across its territory[23] as a proxy for the proportion of savings in each state.
6) In states with both statewide EE programs and utility-level EE programs, the team took care to avoid double-counting the annual energy impacts by carefully reviewing data sources and speaking to state staff, as needed, for clarification.

[23] Source: U.S. Energy Information Administration. 2012. *Form EIA-861 -- Annual Electric Power Industry Report*. http://www.eia.gov/electricity/data/eia861/index.html.

Although this information was less frequently available from data sources, Navigant also considered the following dimensions in the data collection process:

1) Savings distinguished by customer segment (i.e., Residential, Commercial, Industrial, and Other);
2) Savings at the customer level, rather than at the generator;
3) Committed versus planned savings, where *committed* savings are existing savings and those already approved by the utility or commission, and *planned* savings are those that still require future approval;
4) Gross savings, rather than net savings to represent the total amount of savings that may impact transmission planning; and
5) Amortized lifetime savings, rather than lifetime savings reported all in the first year or only first-year savings reported.[24]

Due to the limited data available for these dimensions, the team collected the available data in a consistent manner, but with the exception of the customer segment information (see below), did not conduct additional analysis. Future studies may find additional data sources to explore these areas in more detail.

Base Case Forecast Methodology

Navigant collected data on the EE planned by more than 100 Eastern Interconnection entities in 2012-2015 from IRPs, surveys, interviews, and other publicly-available reports. Since forward-looking EE forecasts could not be collected for all Eastern Interconnection utilities, Navigant sought to fill in gaps for utilities with other information, including 2011 Form EIA-861 data, extrapolation, and growth rate assumptions for 2012-2015. These methods are described in the following paragraphs and shown hierarchically in Figure 3-2.

<u>Existing EE (2012)</u>
Navigant first identified comprehensive, publicly-available sources on EE forecasted at the state-level. Examples include the EE forecasting work done by ISO New England (ISO-NE) to capture the EE efforts of all program administrators in each New England state, as well as Wisconsin's *Strategic Energy Assessment*, which includes the planned EE efforts from both utilities and the statewide EE program.

For states without comprehensive statewide information, Navigant collected utility-level EE forecasts from the survey Navigant conducted on behalf of NARUC, IRPs and other planning documents, or, in a limited number of cases, interviews with utility and state staff. In total, these state-level and utility-level sources include over 70 IRPs representing 29 states, which provided data more than 98% of the estimated EE in 2012.

In some cases, it was unclear whether the EE annual energy impacts collected for 2012 were incremental or cumulative because the data source was vague or 2011 savings were not provided for comparison. To

[24] For utilities that did not report amortized lifetime savings, the project team used a ten year lifetime to amortize the savings. Source: Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S., EPRI, Report No. 1016987, Page 6-1, January 2009.

address this issue, the team compared the 2012 impacts to the incremental EE the utility reported through Form EIA-861 for 2011[25] to benchmark the savings and help determine whether the savings were incremental or cumulative.

Finally, for utilities not already included in the analysis, Navigant used the utility-level data reported through Form EIA-861 to estimate existing EE savings. Since 2012 data were not available at the time of this writing, Navigant used the Form EIA-861 data for 2011 as a proxy for existing EE in 2012. As a result, this is likely a conservative estimate of 2012 EE for these utilities. While Navigant obtained data for more than 100 utilities from Form EIA-861, most of these utilities are small and comprise less than 0.3 GWh/yr of the over 14 GWh/yr of EE savings collected by Navigant from other data sources.

Near-Term EE Forecast (2013-2015)

In addition to the information provided for 2012, many of the state-level and utility-level sources discussed above also include forecasts for EE from 2013 to 2015. The primary exception to this is the Form EIA-861 data, which does not include forward-looking projections. To extrapolate the Form EIA-861 data over 2013-2015, Navigant developed growth rate assumptions based on the data collected from the IRP, ISO, and state-level sources. First, the team grouped utilities by state using EIA and ACEEE data on past EE program performance with the assumption that utilities located in the same state or another state with similar policies and historical EE activity will likely have similar EE deployment trends. Table 3-1 presents these state groupings. The team then calculated average annual growth rates for each group from the collected EE forecast data and used these rates to extrapolate the 2012 data.

Table 3-1. Assumed Groups of States with Similar EE Deployment Trends

Group 1	Group 2	Group 3	Group 4
Vermont	Delaware	District of Columbia	Alabama
Connecticut	Illinois	Florida	Arkansas
Iowa	Maryland	Georgia	Kansas
Massachusetts	Montana	Indiana	Louisiana
Maine	New Hampshire	Kentucky	Mississippi
Michigan	New Jersey	Missouri	North Dakota
Minnesota	Ohio	North Carolina	South Dakota
New York	Pennsylvania	Nebraska	Texas
Rhode Island	Virginia	New Mexico	West Virginia
Wisconsin		Oklahoma	
		South Carolina	
		Tennessee	

[25] The project team used the "incremental effects" from Form EIA-861, which respondents were instructed to submit as "those changes in energy use (measured in megawatt hours) and peak load (measured in megawatts) caused in the current reporting year by new participants in DSM programs that already existed in the previous reporting year, and all participants in your new DSM programs that existed for the first time in the current reporting year."

Long-Term EE Forecast (2016-2030)
In general, the EE long-term Base Case assumptions reflect the relative maturity of EE as a resource and expectation that much of the low-hanging savings have already been achieved; however, current policies and fairly established acceptance by both customers and utilities will continue to drive EE activity.

In extending the Base Case forecast through 2030, Navigant assumed that new EE activity in the long-term stays roughly constant with the near-term EE growth such that the incremental new EE added each year stays constant as a percent of annual energy consumption from 2015 through 2030. As a result, the cumulative forecast grows at a steady rate.[26]

Exceptions to this include the New England, Middle Atlantic, and East North Central Census Regions, which all have very aggressive near-term growth that will likely slow in the long-term. In New England and the Middle Atlantic, ISO-NE and NYISO have developed regionally comprehensive state-level forecasts of all planned EE programmatic savings through 2022. The EE programs are mature in these regions and the incremental EE added each year in the ISO's forecasts decline slightly over time. Instead of the methodology described above, these forecasts are used for 2016-2022 in the ISO's representative states. To extend the forecasts to 2030, rather than hold the incremental EE constant as a percent of energy consumption as done in the other regions, the team continued to decline the incremental EE percentages to reach 16% and around 12% cumulative EE in 2030 for the New England and Middle Atlantic Regions, respectively. In East North Central, the team similarly decreased the incremental EE starting in 2016, such that the region reaches 13% cumulative EE in 2030. Even with EE growth slowing down over time, these regions still have the highest cumulative penetrations of EE in 2030.

Estimated Customer Sector Breakdowns
As part of the data collection process, Navigant collected available information on whether the EE savings were achieved through the residential, commercial, industrial, or other customer sectors. As this information was not available from all sources, a thorough analysis by customer sector was not possible. Additionally, many sources with customer sector data did not explicitly distinguish the commercial, industrial, and other sectors from one another. However, the collected data suggests general trends in aggregate, which are presented in Section 3.1.3 as the proportion of residential versus non-residential savings.

Scenario Analysis Approach

For the scenario analysis of EE, the team adjusted the additional growth factors to account for the changes in scenario driver conditions. The team assumed that the following drivers were particularly influential to the adoption of EE:

- **Energy Policies that Support Demand-Side Resources:** The primary driver for EE is expected to be local, state, and Federal policy supporting EE, such as Energy Efficiency Resource Standards (EERS) or greenhouse gas regulations. This also includes market rules and regulations governing EE's participation in organized capacity markets within the ISO/RTO regions, but

[26] The team also assumed that energy efficient equipment is replaced at the end of the equipment's useful life with similar or more efficient equipment, such that the energy savings already achieved do not diminish significantly over time.

does not include the EE savings directly attributable to code and standard changes, which are not within the scope of this analysis.

- **Retail Electricity Prices:** Higher utility bills are one of the key drivers for customer investment in EE as a way to reduce household bills or operational costs. More attractive paybacks can also encourage customers to invest in more significant EE measures that may have higher upfront capital costs, but yield greater potential savings.
- **Technology Advancement:** While advancements in end-use technologies are expected to play a more minor role than policies and retail prices in future EE penetration, more efficient technologies and emerging tools that allow customers to better understand and control their energy consumption will likely create new conservation opportunities and contribute to increased EE.

Beyond these three drivers, the team assumed that customer acceptance is already relatively high for EE and will not change significantly across the scenarios. The team also assumed that changes in economic growth and natural gas prices will not have significant impacts on the forecast.

3.1.3 Results

Base Case Results

For the Eastern Interconnection, the Base Case results suggest that cumulative EE savings will be about 9.0% of annual energy consumption in 2030, and annual incremental savings will grow at an average annual rate of around 0.47% of annual energy consumption. Table 3-2 and Table 3-3 present the Base Case forecasts of EE annual energy impact and peak load impact through 2030, respectively, aggregated by U.S. Census Region as the total cumulative impacts since 2011. As resource capacity and peak load impact are considered the same for EE in this analysis, Table 3-3 also shows the EE resource capacity. Refer to Appendix A for a state-by-state breakdown of each forecast.

Table 3-2. Projected EE Annual Energy Impact by U.S. Census Region – Cumulative Relative to 2011

U.S. Census Division	U.S. Census Region	Projected EE Annual Energy Impact (GWh/yr)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	1,308	2,422	3,795	5,414	12,433	17,363	21,070
	Middle Atlantic	4,562	7,415	10,654	13,449	24,676	34,488	45,566
Midwest	East North Central	4,313	8,931	13,942	19,447	39,427	58,793	72,606
	West North Central [a]	1,396	2,229	3,324	4,409	10,907	17,648	24,645
South	South Atlantic	3,034	6,184	9,458	12,909	34,879	58,060	81,391
	East South Central	632	1,217	1,867	2,423	5,722	9,430	13,095
	West South Central [a b]	387	772	1,217	1,683	4,043	6,598	9,143
TOTAL		15,631	29,170	44,258	59,733	132,087	202,381	267,514

a. *Portions of both Montana and New Mexico fall within Eastern Interconnection territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

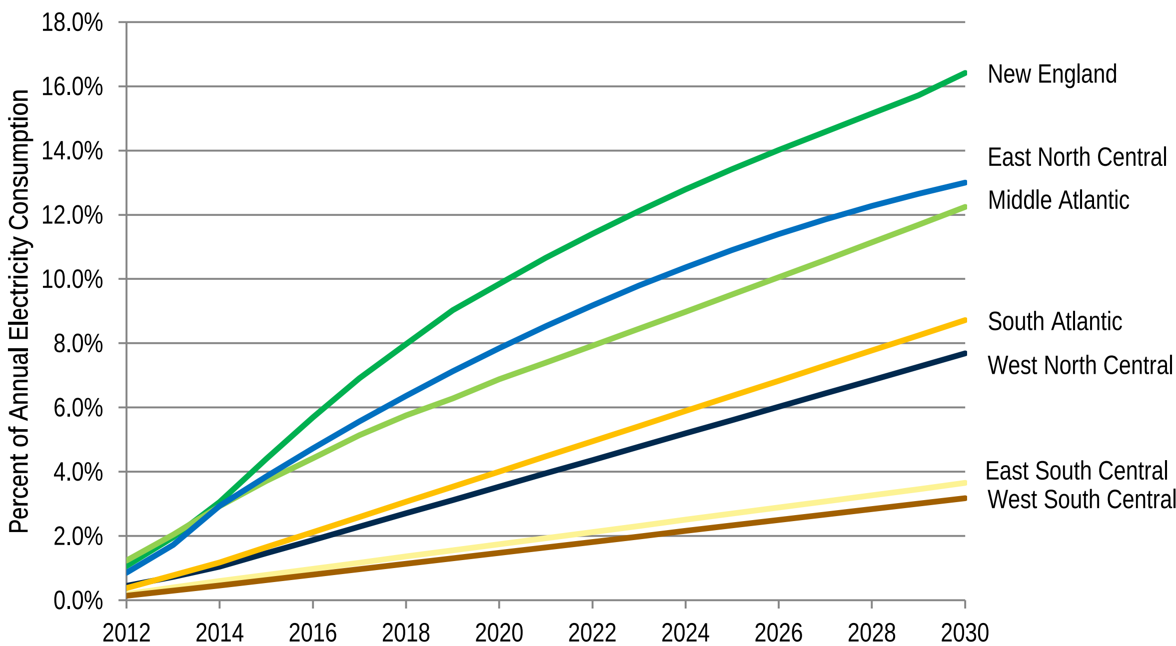
Table 3-3. Projected EE Resource Capacity and Peak Load Impact by U.S. Census Region – Cumulative Relative to 2011

U.S. Census Division	U.S. Census Region	Projected EE Resource Capacity and Peak Load Impact (MW)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	203	382	605	872	2,028	2,820	3,338
	Middle Atlantic	909	1,470	2,107	2,654	4,894	6,895	9,158
Midwest	East North Central	704	1,463	2,298	3,229	6,622	9,901	12,235
	West North Central [a]	278	433	634	833	2,032	3,276	4,568
South	South Atlantic	734	1,537	2,357	3,196	8,551	14,199	19,882
	East South Central	120	232	354	465	1,122	1,861	2,592
	West South Central [a b]	68	134	213	294	707	1,153	1,597
TOTAL		3,016	5,650	8,567	11,542	25,956	40,106	53,369

a. *Portions of both Montana and New Mexico fall within Eastern Interconnection territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

Based on our forecast, EE will steadily increase for all regions of the Eastern Interconnection. The South Atlantic and East North Central Regions are projected to have the most cumulative EE in 2030, partly because of the Regions' size and because of existing conditions favorable for EE growth, including EERS in many of the states. As Figure 3-3 shows, however, New England, East North Central, and Middle Atlantic are expected to have the most EE as a percent of annual energy consumption. This is reinforced by Table 3-4, which shows the average incremental EE added each year over the analysis timeframe as a percent of annual energy consumption. Even with the annual incremental EE declining in the long-term in these regions (see discussion in Section 3.1.2), they still have strong near-term EE activity and the highest average growth rates. The lowest penetration and growth is expected in the South Central Region.

Figure 3-3. EE Annual Energy Impact as a Percent of Regional Electricity Consumption – Cumulative Relative to 2011



Note: These results assume that the amount of new EE each year stays constant in the long-term as a percent of annual electricity consumption, but the cumulative forecast continues to grow. Exceptions include New England, East North Central, and Middle Atlantic (see text).

Table 3-4. Average Annual Incremental EE Energy Impact by U.S. Census Region

U.S. Census Division	U.S. Census Region	2012-2020 (%)	2012-2030 (%)
Northeast	New England	1.09%	0.86%
	Middle Atlantic	0.76%	0.64%
Midwest	East North Central	0.87%	0.68%
	West North Central [a]	0.39%	0.40%
South	South Atlantic	0.45%	0.46%
	East South Central	0.19%	0.19%
	West South Central [a b]	0.16%	0.17%
TOTAL		0.53%	0.48%

a. *Portions of both Montana and New Mexico fall within Eastern Interconnection territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

In general, the regions that historically have the strongest EE initiatives continue to lead in terms of EE penetration and growth. These include the Middle Atlantic, East North Central, and New England Regions. New England is forecasted to have the highest penetration of EE at 4.4% of annual electricity consumption in 2015 and just over 16% by 2030.

Navigant also estimated the proportion of EE annual energy impacts by customer sector. From the data collected for this analysis, Navigant estimates that about 55% of EE annual energy impact in 2012 is from non-residential customers and 45% is from residential customers. The proportion of EE from each of the customer sectors is assumed to be relatively constant over the analysis timeframe.

Scenario Results

Table 3-5 and Figure 3-4 present the forecast of EE annual energy impact through 2030 for the Base Case and four scenarios outlined in Section 3.1.2. The team assumed that the near-term EE impacts projected for 2012 through 2015 are the same in all scenarios since much of this EE is already committed (e.g., in statewide plans, IRPs, regulatory filings, etc.) and changes in the key scenario drivers are unlikely to impact the market quickly enough to affect significantly the EE committed through 2015. Table 3-6 also presents the average incremental EE added each year as a percent of annual energy consumption for each scenario.

Table 3-5. Scenario Analysis of EE Annual Energy Impact through 2030 – Cumulative to 2011

Scenario	Projected EE Annual Energy Impact - Cumulative to 2011 (GWh)						
	2012	2013	2014	2015	2020	2025	2030
Base Case	15,631	29,170	44,258	59,733	132,087	202,381	267,514
Scenario 1	15,631	29,170	44,258	59,733	180,844	251,155	321,017
Scenario 2	15,631	29,170	44,258	59,733	122,841	188,214	248,788
Scenario 3	15,631	29,170	44,258	59,733	164,579	225,684	286,240
Scenario 4	15,631	29,170	44,258	59,733	103,165	107,762	110,386

Figure 3-4. Scenario Analysis of EE Annual Energy Impact through 2030 – Cumulative to 2011

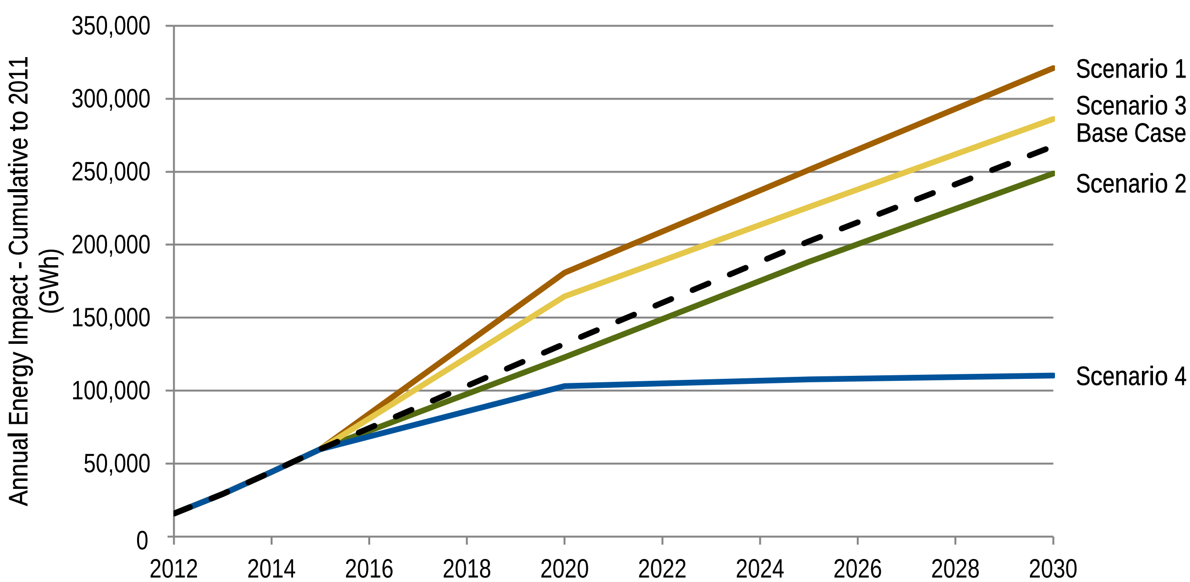


Table 3-6. Average Annual Incremental EE Energy Impact by Scenario

Scenario	2012-2020 (%)	2012-2030 (%)
Base Case	0.53%	0.48%
Scenario 1	0.72%	0.57%
Scenario 2	0.49%	0.44%
Scenario 3	0.66%	0.51%
Scenario 4	0.41%	0.20%

As shown above, Scenario 1 (with aggressive policy goals and strong economic growth) has the largest annual energy impact at 20% higher than the Base Case through 2030, as a result of the assumed high electricity prices and robust demand-side policies. The next highest scenario is Scenario 3 (with aggressive policy goals and weak economic growth), which is 7% higher than the Base Case through 2030, as a result of the assumed demand-side policies and state's higher targets. Both Scenarios 1 and 3 reflect higher growth through 2020 with more moderate growth afterwards to show the most significant policy impacts occurring in the mid-term and then leveling off in the long-term. Scenario 2 (with strong economic growth and relaxed policy goals) is 7% lower than the Base Case by 2030 to reflect weaker policy drivers, but otherwise favorable conditions. Scenario 4 (weak economic growth and relaxed policy goals) is lower than the Base Case because, in the absence of supporting policies, the low retail electricity prices lead to customer resistance to new EE investments.

These results align with recent EE projections from Lawrence Berkeley National Laboratory (LBNL), which show annual incremental savings from customer-funded EE programs in the U.S. increasing from about 0.5% of electric utility retail sales in 2010 to 0.8% in 2025 at an average annual incremental rate of 0.72%. For comparison, Navigant estimates that incremental savings from customer-funded EE programs in the Eastern Interconnection are 0.58% of retail sales in 2012. While the LBNL forecast shows incremental EE savings increasing as a percent of retail sales, Navigant's Base Case finds that the incremental savings decrease in the long-term to 0.39% of retail sales in 2030. As a result, Navigant's average incremental EE in the Base Case is lower than LBNL's projections in the long-term. As shown in Table 3-6, however, the annual incremental savings for Scenario 1 from 2012-2020 reflect similar growth trends as the LBNL forecast.

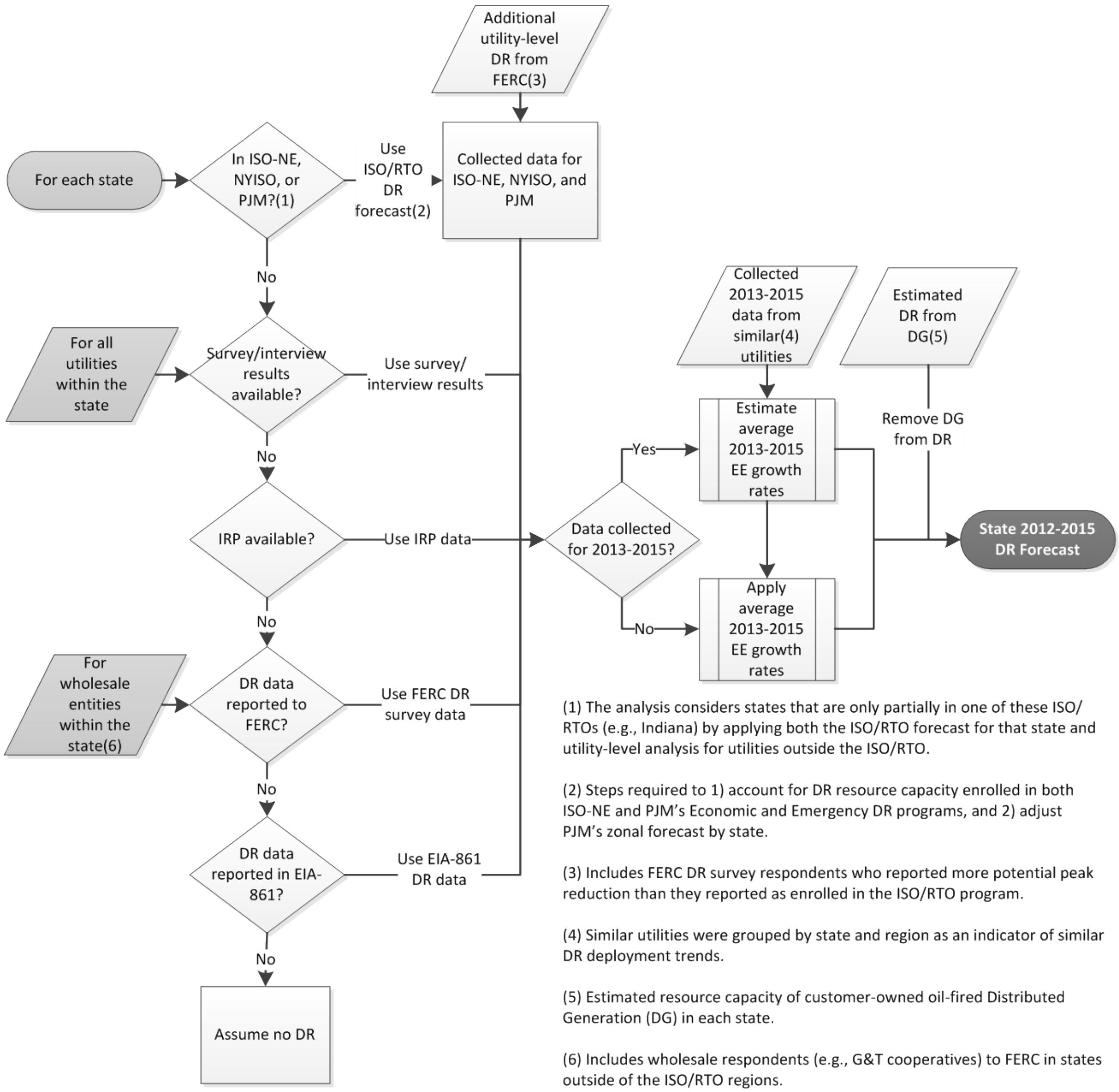
3.2 *Study #2: Demand Response*

Navigant forecasted the penetration of existing and planned demand response (DR) within the Eastern Interconnection with attention to the following dimensions:

- State,
- DR resource type (e.g., Direct Load Control, Time-Based Rates, etc.), and
- Customer segment (i.e., Residential, C&I).

This analysis represents a bottom-up forecast based on aggregated, publicly-available data and a limited number of confidential sources. To synthesize the various data sources, the project team compiled the collected data in a model built in SAS® analytics software and applied the normalization and analysis steps shown in Figure 3-5, such that aggregation could occur meaningfully and accurately. Sections 3.2.1 and 3.2.2 describe the data sources, assumptions, and forecasting approach in more detail.

Figure 3-5. Overview of DR Analysis Methodology and Data Sources



(1) The analysis considers states that are only partially in one of these ISO/RTOs (e.g., Indiana) by applying both the ISO/RTO forecast for that state and utility-level analysis for utilities outside the ISO/RTO.

(2) Steps required to 1) account for DR resource capacity enrolled in both ISO-NE and PJM's Economic and Emergency DR programs, and 2) adjust PJM's zonal forecast by state.

(3) Includes FERC DR survey respondents who reported more potential peak reduction than they reported as enrolled in the ISO/RTO program.

(4) Similar utilities were grouped by state and region as an indicator of similar DR deployment trends.

(5) Estimated resource capacity of customer-owned oil-fired Distributed Generation (DG) in each state.

(6) Includes wholesale respondents (e.g., G&T cooperatives) to FERC in states outside of the ISO/RTO regions.

3.2.1 Sources and Data Collection

The primary sources of data used for the DR analysis are ISO/RTO forecasts in states that allow DR to participate in capacity markets and utility Integrated Resource Plans (IRPs)[27] for all other states. While not all states in the Eastern Interconnection require utilities to file an IRP, roughly three-quarters of the states do require utilities to file an IRP or some other type of long-term plan. These IRPs typically contain forecasts of existing and planned load, energy, EE, and DR for the utility, and sometimes contain information about customer segments and program types. Navigant collected data from over 70 IRPs in 29 states, which represent about 75% of the states in the Eastern Interconnection.

In instances when utilities are not required to file an IRP, only have older or confidential IRPs, or offer DR programs within an ISO/RTO that do not participate in the ISO/RTO markets, Navigant used other primary and secondary sources to augment the ISO/RTO and IRP data. Two of the key sources used to fill in data gaps were the Federal Energy Regulatory Commission's (FERC) *Assessment of Demand Response & Advanced Metering* survey, which collects data from utilities on their existing and near-term plans for DR programs, and the Energy Information Administration (EIA)'s Annual Electric Power Industry Report (Form EIA-861), which collects data from utilities on their existing demand-side management programs. Navigant also spoke to utility, ISO/RTO, and commission staff; used utility-level data collected through the surveys conducted on behalf of NARUC; reviewed state-level data on statewide programs and initiatives; and benchmarked results against the North American Electric Reliability Corporation's (NERC) *2012 Long-Term Reliability Assessment*. For a complete list of sources reviewed and used, please see Section 6.

In addition to DR resource capacity and peak demand impact, Navigant also collected available information on the type of DR program, applicable customer segments, whether the resource was incremental or cumulative, and a number of other characteristics that informed the normalization process. These characteristics are discussed in Section 3.2.2.

3.2.2 Analysis Approach

The goal of this analysis is to forecast the adoption of demand-side resources, such as DR, and the associated impact on electricity demand in terms of three factors: resource capacity; annual energy impact; and peak load impact. In the context of the DR forecast, these factors are defined as follows:

- **Resource capacity** refers to the reduction in gross electricity generation capacity required within the Eastern Interconnection due to the total end use load reduction capabilities available from DR program participants;
- **Annual energy impact** refers to the estimated change in gross annual electricity generation within the Eastern Interconnection due to an actual net change in the end use energy consumption of DR program participants (i.e., taking into account the snapback effect); and
- **Peak load impact** refers to the estimated change in annual peak demand within the Eastern Interconnection due to the actual change of end use load by DR program participants.

[27] The term "Integrated Resource Plan" is used in this report to describe a utility's forward-looking resource plan filed with their state commission. For the purposes of this report, IRP also refers to documents that are not called an IRP (e.g., Florida's Ten-Year Site Plans or Maryland's Energy Efficiency and Conservation Plans), but have the same intent as an IRP.

The ratio of actual peak load impact to available resource capacity is referred to in this report as the *realization rate* for DR, and it is discussed in the following paragraphs.

Considerations and Identified Issues

As each source used its own set of assumptions and dimensions to forecast and characterize DR savings, Navigant took a number of steps to normalize the collected data and make it consistent for aggregation. Key steps and assumptions include the following:

1) Based on the expectation that most customers will reduce peak demand by shifting their load off-peak, Navigant assumed negligible annual energy impact from DR. This assumption is consistent with the data collected from IRPs and other sources, where most entities do not forecast energy savings from DR.[28]
2) Some utilities presented a combined forecast of EE and DR. In such cases, to estimate the distinct savings from DR and EE, Navigant looked at the ratio of EE to DR savings for utilities in all the states that reported both types separately. The team found that on average, out of a utility's EE/DR resource capacity, 80% came from DR savings and 20% from EE savings, while virtually all of the utility's EE/DR annual energy impacts came from EE. These average ratios of EE to DR for resource capacity and annual energy impacts were then applied to forecasts with combined EE and DR.
3) Winter and summer peak demand impacts were not distinguished in the analysis results because insufficient data was available to assess them individually. If both winter and summer peak demand impacts were available for an entity, the maximum was used.
4) Navigant addressed five potential ways in which the total amount of DR could be double-counted. They are described here:
    a) **Wholesale versus retail DR:** Particularly in the ISO/RTO regions, a DR resource may participate at the wholesale level, at the retail level, or at both. To avoid double-counting DR that is reported by both wholesale and retail entities, Navigant used the following processes:
        i) Navigant interviewed ISO/RTO staff to help identify the best available DR forecasts for each ISO/RTO.[29] These ISO/RTO forecasts comprise the majority of the DR in these regions; however, some DR does occur outside the ISO/RTO markets. To capture these savings, Navigant supplemented the ISO/RTO data with the FERC DR survey respondents who reported more potential peak reduction than they reported as enrolled in the ISO/RTO program.
        ii) Other DR provided at the wholesale level might include DR offered by an electric distribution company directly to a wholesale customer, such as a large industrial customer on a wholesale tariff, or DR offered through wholesalers like generation and

[28] While some studies have found energy savings from time-based rates, specifically time of use rates, the savings have typically been very small and some recent studies have shown very small *increases* in energy consumption, the causes of which are unknown at this time.

[29] Regional forecasts were identified for ISO-NE, NYISO, and PJM; however, no comprehensive regional forecast was identified for MISO, so Navigant developed the DR forecast using state- and utility-level sources. Since the PJM forecasts DR on a zonal basis, Navigant used the portion of zonal load in each state to allocate the DR savings by state. Source: "Estimated State Load – Hourly," FERC Form 714 Part III Schedule 2, EIA Form-861, Ventyx research.

transmission cooperatives or energy service providers. While the potential exists for double-counting the savings reported by these wholesale entities with savings reported by the retail entities they represent, with limited time and resources available to look at each case individually, unless otherwise specified, Navigant adopted the data provided by FERC and included the savings from both the wholesale and retail entities in the total.

b) **Participating in multiple programs:** Many DR programs allow participants to enroll in multiple programs; however, those participants are unable to provide peak reduction in more than one program with the same load at the same time. Other than for the Economic and Emergency/Reliability DR programs in ISO-NE and PJM, there exists limited information on quantifying the portion of DR enrolled in multiple programs; therefore, Navigant did not adjust for this potential overlap. Using publicly available information, the team assumed that all of the Economic DR in ISO-NE[30] and around 1,850 of the 2,270 MW of Economic DR in PJM[31] is also enrolled as Emergency/Reliability DR. Thus, the analysis includes no incremental Economic DR for ISO-NE and about 420 MW of Economic DR for PJM.

c) **Distributed generation:** Distributed generation (DG) (e.g., standby diesel generators) is eligible for participating in many DR programs across the country. Since the resource capacity of DG is captured elsewhere in this analysis (see Sections 3.4 and 3.5), Navigant estimated the portion of forecasted DR from DG and removed this portion from the DR forecast to avoid double-counting DG capacity. While the portion of DR from DG is not publicly available for many programs, a report by the Northeast States for Coordinated Air Use Management (NESCAUM) estimates that DG comprises 10 to 23% of DR enrolled in the NYISO, PJM, and ISO-NE capacity markets. The Environmental Law & Policy Center estimates up to 41% of DR participation in MISO is from DG. As only customer-owned diesel generators are likely to participate in DR programs, Navigant compared the total resource capacity of customer-owned oil-fired DG forecasted for each state32 to the total DR capacity for each state and found that the estimated DG capacity is significantly less than 10 to 41% of the estimated DR capacity in most states. This suggests that the resources used to develop the forecast of customer-owned oil-fired DG may not adequately capture the amount of actual capacity on the grid. Thus, Navigant subtracted the total amount of customer-owned oil-fired DG from the DR forecasted for each state as a conservative estimate of the DG capacity participating in DR programs[33]. As a result, the total DR numbers presented in this report likely represent some capacity contributions from DG.

[30] ISO New England, Demand Resources Working Group, December 2012, available at http://www.iso-ne.com/committees/comm_wkgrps/mrkts_comm/dr_wkgrp/mtrls/2012/dec52012/a01_intro_drwg_mtg_12_05_2012.ppt.

[31] PJM, Load Response Activity Report, July 2012, available at http://pjm.com/markets-and-operations/demandresponse/~/media/markets-ops/dsr/2012-dsr-activity-report-20120712.ashx.

[32] Customer-owned DG includes DG owned by Commercial and Industrial customers. Oil-fired DG includes diesel fuel, as well as other fossil fuel like jet fuel and kerosene; however, the impact of those other fuels on the results is considered to be negligible for the purposes of this analysis. See Section 3.4 for more discussion on the DG forecast.

[33] Limited exceptions to this methodology included ISO-NE, where DG can only participate in ISO-NE's Real Time Emergency Generation (RTEG) program. In this case, Navigant excluded the RTEG program from the DR forecast and did not subtract any estimated DG from the final DR forecast.

d) **Smart grid:** As described in Section 3.6, smart grid savings are estimated from smart grid-enabled time-based rates and conservation voltage reduction (CVR). The savings from smart grid-enabled time-based rates are included in the total DR savings presented in this section and should not be added together. CVR savings are only captured under smart grid.
e) **Energy efficiency:** More efficient end-use loads can reduce the amount of peak reduction capacity available from that end-use. For example, improving the efficiency of a customer's air conditioning unit can decrease the amount of capacity considered available for reduction from that air conditioning unit. These effects are not considered in this analysis because the total impact of EE on available DR resource capacity is thought to be relatively small.

5) For the purposes of this analysis, Navigant grouped different DR program types into the following *sub-resource categories* for DR: Direct Load Control, Time-Based Rates, Emergency/Reliability C&I DR, Economic C&I DR, and Other. See Appendix C for descriptions of each category.
6) Many utilities with service territories spanning more than one state did not report savings separately for each state. In these cases, Navigant used the ratio of utility-reported bundled-delivered energy in each state to the total bundled-delivered energy across its territory[34] as a proxy for the proportion of savings in each state.

Navigant also considered the following dimensions in the data collection process; however, this information was less frequently available from data sources:

a) Coincidence with utility and system peak;
b) The realization rate of available resource capacity to actual peak load impact for DR;
c) Savings broken out by customer segment (i.e., Residential, Commercial, Industrial, and Other);
d) Savings at the customer level, rather than at the generator;
e) Cumulative versus incremental savings, where *cumulative* savings include both new and existing DR savings and *incremental* savings only include new savings in a given year;
f) Committed versus planned savings, where *committed* savings are existing savings and those already approved by the utility or commission and *planned* savings are those that still require future approval; and
g) Gross savings, rather than net savings, to represent the total amount of savings that may impact transmission planning.

Due to the limited data available for these dimensions, the team collected the available data in a consistent manner, but with the exception of the realization rate and customer segment information (see below), did not conduct additional analysis. Future studies may find additional data sources to explore these areas in more detail.

Base Case Forecast Methodology

Navigant collected data on the DR planned by more than 100 Eastern Interconnection entities in 2012-2015 from IRPs, surveys, interviews, and other publicly-available reports. Since forward-looking DR forecasts could not be collected for all Eastern Interconnection utilities, Navigant sought to fill in gaps

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[34] Source: U.S. Energy Information Administration. 2012. *Form EIA-861 -- Annual Electric Power Industry Report*. http://www.eia.gov/electricity/data/eia861/index.html.

with other information, including data on DR performance in 2011 from FERC's 2012 DR survey, extrapolation, and growth rate assumptions for 2012-2015. Navigant then used NERC's 2012 Long-Term Reliability Assessment (2012 LTRA) to extrapolate all utilities' 2015 DR out to 2030, based on regional peak demand growth. These methods are described in the following paragraphs and shown hierarchically in Figure 3-5.

Existing DR (2012)

Navigant first identified publicly available sources on DR forecasted at the state-level, which primarily included ISO/RTO load forecasts and capacity market projections. In ISO-NE, NYISO, and PJM, the ISO/RTO DR's forecasts are used rather than utility-level forecasts, with one exception to capture utility DR that does not participate in organized DR markets: if a FERC DR survey respondents reported more potential peak reduction than what they reported as enrolled in the ISO/RTO program, the difference between the two was added to the ISO/RTO forecast.

For states without this information available, Navigant collected utility-level DR forecasts from the survey it conducted on behalf of NARUC, IRPs and other planning documents, and, in a limited number of cases, interviews with utility and state staff. In total, these sources included over 70 IRPs representing 29 states and provided more than 70% of the estimated DR resource capacity in 2012.

For entities not already included in the analysis, Navigant used utility-level data reported through FERC's 2012 DR survey[35] and Form EIA-861 for utilities that did not respond to the FERC survey to estimate existing DR savings. As 2012 data were not available at the time of this writing, Navigant used the FERC and EIA data on DR performance in 2011 as a proxy for existing DR in 2012. Thus, this is likely a conservative estimate of 2012 DR for these utilities. In total, Navigant used data for more than 100 utilities, most of which are smaller utilities, from FERC's DR survey and EIA. Savings from the FERC survey comprise about 9.5 GW and savings from Form EIA-861 comprise about 1.1 GW of the almost 40 GW of DR savings collected by Navigant from all data sources.

To avoid double-counting DR resource capacity, these various data sources were aggregated according to the steps discussed above in the Considerations and Identified Issues section.

Near-Term DR Forecast (2013-2015)

While much of the data collected from IRPs includes DR penetration through 2015, this information was not available for all utilities, including the utilities added through the FERC DR survey. To extrapolate the 2012 DR data to those utilities without forecast data collected in 2013 to 2015, Navigant developed growth rate assumptions based on the data collected from the IRP, ISO, and state-level data sources.

The team first grouped utilities by state and by NERC or ISO/RTO region (see Table 3-7) under the assumption that regional similarities in policies, level of historical DR activity, and market rules are key predictors for DR growth across these groupings. The team then calculated average growth rates for each year from the collected DR forecast data and used these rates to extrapolate the 2012 data. For ISO-

[35] The project team used the "potential peak reduction" from FERC's DR survey, which respondents were instructed to submit as "the potential peak reduction in megawatts attributable to the group of customers… in this program/tariff. For utilities, this is the sum of potential demand reduction capability achieved by the program participants at the time of their annual peak load…"

NE, NYISO, PJM, and FRCC, the team applied the same growth rates as calculated from the collected data, since uniform regional market drivers and more mature markets are expected to motivate utilities in a more consistent manner. For MISO, SPP, and SERC, the team reduced the growth rates by half to reflect greater uncertainty and fewer motivating factors in near-term DR growth for utilities in these regions, particularly for the smaller ones that are less likely to have IRP forecasts available.

Table 3-7. Assumed Groups of States with Similar DR Deployment Trends

FRCC	ISO-NE	MISO	PJM	NYISO	SERC	SPP
Florida	Connecticut	Iowa	DC	New York	Alabama	Kansas
	Massachusetts	Indiana	Delaware		Arkansas	Missouri
	Maine	Michigan	Illinois		Georgia	Nebraska
	New Hampshire	Minnesota	Maryland		Kentucky	New Mexico
	Rhode Island	Montana	New Jersey		Louisiana	Oklahoma
	Vermont	North Dakota	Ohio		Mississippi	Texas
		South Dakota	Pennsylvania		North Carolina	
		Wisconsin	Virginia		South Carolina	
			West Virginia		Tennessee	

Notes: For states in more than one region, the grouping is based on the region with the greatest share of the state's retail activity.

Long-Term DR Forecast (2016-2030)

To extend the forecast through 2030, Navigant assumed that the growth in DR savings will level off to parallel the growth in peak demand so that that DR resource capacity will stay constant as a percent of peak demand from 2015-2030. The exception to this includes New England where the recent ISO-NE capacity auction results significantly decreased from 1400 MW of DR capacity in 2015 to less than 900 MW of in 2016[36]. To capture this decrease, Navigant used the ISO-NE's 2016 auction results in 2016 and assumed that the DR capacity in 2016 stays constant as a percent of peak demand, rather than the DR capacity in 2015 staying constant.

This slowing growth of DR is a general trend indicated in the IRPs and other collected DR forecasts. This assumption is also consistent with the Optimistic BAU case in Oak Ridge National Laboratory's *Eastern Interconnection Demand Response Potential* study that was recently completed for EISPC and shows DR growth leveling off to match demand growth in about the same timeframe.

Estimated Customer Sector Breakdowns

As part of the data collection process, Navigant collected available information on whether the DR savings were achieved through the residential, commercial, industrial, or other customer sectors. Since this information was not available from all sources, a thorough analysis by customer sector was not possible. Additionally, many sources with customer sector data did not explicitly distinguish the commercial, industrial, and other sectors from one another. However, the collected data suggests

[36] For consistency, ISO-NE's DR resource capacity numbers for 2012-2016 are based on the Real-Time Demand Response cleared in the primary Forward Capacity Auctions, although the actual capacity that participates in the market has historically been less after reconfiguration auctions.

general trends in aggregate, which are presented in Section 3.2.3 as the average proportion of residential versus non-residential savings.

Estimating the DR Sub-Resource Categories

To the extent possible, the project team sought to collect data on DR program type to develop estimates of DR penetration by sub-resource category. These categories include Direct Load Control, Emergency/Reliability DR, Economic DR, and Time-Based Rates. Time-Based Rates is further divided into smart grid-enabled Time-Based Rates, which require two-way communications like Advanced Metering Infrastructure (AMI), and traditional Time-Based Rates that do not rely on AMI meters (i.e., primarily Time of Use rates with Automatic Meter Reading (AMR) meters). This distinction is discussed more in Section 3.6.

Since sub-resource category data was not always available from secondary sources, Navigant assumed that the average breakdown of sub-resource categories for entities with data available from IRPs, ISO/RTOs, and FERC applies to other entities without available data within the same region. For these purposes, the team used the same regional groupings as in the near-term extrapolation.

Adjusting from DR Resource Capacity to Peak Demand Impact

The majority of data collected on DR savings was in terms of resource capacity because sources like IRPs and ISO forecasts typically consider the amount of DR available to decrease resource requirements or reserve margins. As discussed at the beginning of Section 3.2.2, the ratio of actual peak load impact to available resource capacity is referred to here as the *realization rate* for DR. To find the realization rates, Navigant used the ratio of potential peak reduction to realized (or actual) peak reduction reported by respondents to FERC's 2012 DR survey. The team only used respondents within the Eastern Interconnection and averaged the realization rates over each different program type, assuming that realization rates tend to be more consistent for similar control and event types. As expected, the dispatchable resource types like Direct Load Control and Emergency/Reliability DR have higher realization rates than the largely non-dispatchable Time-Based Rates category. It is worth noting that these realization rates may be lessened at higher DR penetrations or under more frequent calling of DR events due to customer fatigue and higher likelihood of resources not being available for curtailment.

Table 3-8. Realization Rates for Adjusting DR Resource Capacity to Peak Demand Impact

Sub-Resource Category	Realization Rate
Direct Load Control	63%
Time-Based Rates	45%
Emergency/Reliability DR	67%
Economic DR	42%
Other DR	78%

Notes: Based on the ratio of potential peak reduction to realized peak reduction reported by respondents within the Eastern Interconnection to FERC's 2012 DR survey. Only programs with a realized peak reduction greater than zero were included to adjust (to the extent possible) for programs which were available, but not called, during the survey timeframe.

Scenario Analysis Approach

For the scenario analysis of DR, the team adjusted the additional growth factors to account for the changes in scenario driver conditions. The team assumed that the following drivers were particularly influential to the adoption of DR:

- **Energy Policies that Support Demand-Side Resources:** One of the primary drivers for DR is expected to be state, regional, and federal policy supporting DR, particularly regulations that guide resource participation in organized markets and market rules. Policies supporting renewables (e.g., Renewable Portfolio Standards) may also indirectly affect DR resource capacity, since DR deployed as ancillary services to support renewables integration may also be used for peak reduction.
- **Economic Growth:** Changes in economic growth typically impact load growth. One of the key reasons utilities adopt DR is to meet increased load growth in a more cost-effective way than building new capacity. Thus, strong economic growth is expected to lead to higher DR penetration.
- **Customer Acceptance:** The success of DR programs relies on customers' willingness to participate. While some types of DR programs, such as direct load control, are relatively well-established with customers and have fairly predictable event participation rates, the enrollment and event response rates are more uncertain for newer programs like time-based rates. Greater customer acceptance leads to more available DR resource capacity and higher peak demand impacts.
- **Technology Advancement:** Advancements in control systems and communications, including lower installation and integration costs as these technologies become more mature, are expected to play a significant role in future DR growth. Broad adoption of technologies such as advanced meters, programmable communicating thermostats, and Automated Demand Response (Auto-DR) will allow customers and utilities to control a wider range of end-use loads with greater confidence, reliability, and fidelity.

Beyond these drivers, the team assumed that retail electricity rates could impact DR if tied to a time-based rate structure that incentivizes peak reduction, but will not otherwise play a significant role. The team assumed that changes in natural gas prices will not have significant impacts on the forecast.

3.2.3 Results

Base Case Results

For the Eastern Interconnection, the Base Case results suggest that DR resource capacity will be about 8.7% of annual energy consumption in 2030. Table 3-9 and Table 3-10 present the forecasts of DR resource capacity and peak load impact through 2030, respectively, aggregated by U.S. Census Region. Annual energy impact is not presented here, since as discussed in Section 3.2.2, a negligible change in annual energy impact is assumed for DR. Refer to Appendix A for a state-by-state breakdown of each forecast.

Table 3-9. Projected DR Resource Capacity by U.S. Census Region

U.S. Census Division	U.S. Census Region	Projected DR Resource Capacity (MW)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	1,253	1,435	1,460	1,462	899	957	1,025
	Middle Atlantic	6,767	8,416	9,539	9,706	10,230	10,800	11,427
Midwest	East North Central	6,694	7,352	9,981	10,298	10,848	11,439	12,080
	West North Central [a]	6,035	6,670	7,252	7,569	7,969	8,362	8,779
South	South Atlantic	11,657	13,033	15,638	16,032	17,002	18,078	19,232
	East South Central	4,785	4,993	5,420	5,494	5,881	6,286	6,730
	West South Central [a b]	1,931	2,035	2,409	2,586	2,746	2,877	3,026
TOTAL		39,123	43,933	51,698	53,148	55,574	58,799	62,298

a. *Portions of both Montana and New Mexico fall within Eastern Interconnection territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

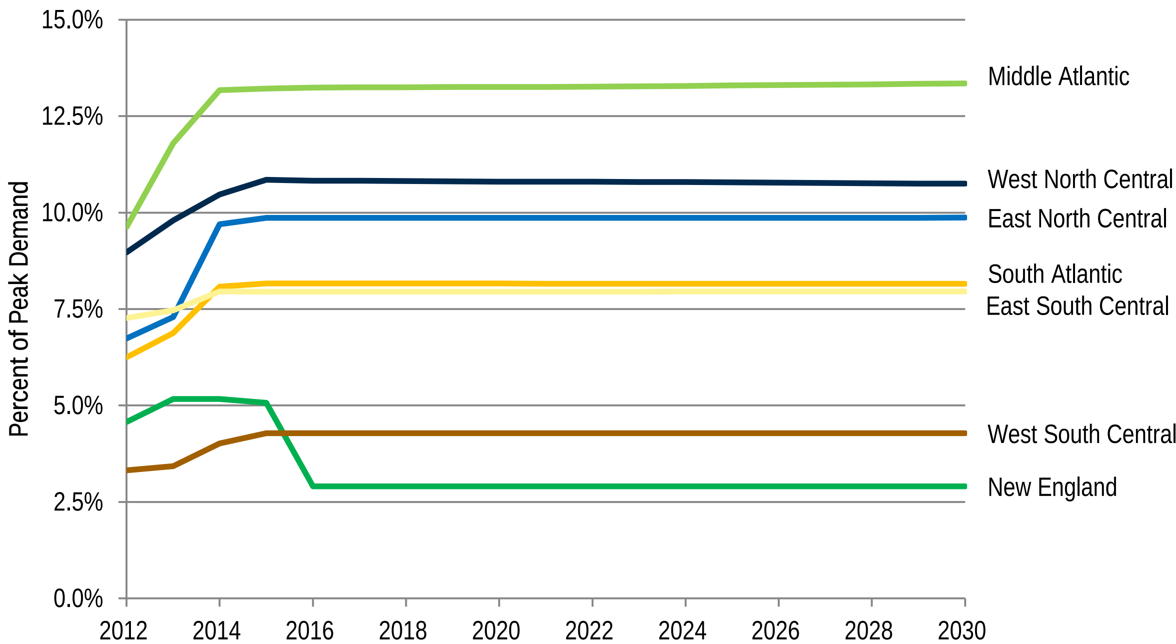
Table 3-10. Projected DR Peak Load Impact by U.S. Census Region

U.S. Census Division	U.S. Census Region	Projected DR Resource Capacity (MW)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	792	907	923	925	572	609	653
	Middle Atlantic	4,346	5,411	6,134	6,240	6,577	6,944	7,347
Midwest	East North Central	4,291	4,707	6,418	6,614	6,968	7,349	7,761
	West North Central [a]	3,759	4,151	4,509	4,704	4,953	5,198	5,457
South	South Atlantic	7,314	8,181	9,828	10,069	10,678	11,353	12,077
	East South Central	2,747	2,867	3,125	3,170	3,392	3,627	3,882
	West South Central [a b]	1,194	1,260	1,492	1,604	1,703	1,784	1,877
TOTAL		24,443	27,484	32,429	33,327	34,844	36,863	39,054

a. *Portions of both Montana and New Mexico fall within Eastern Interconnection territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

Based on our forecast, DR will steadily increase for all regions of the Eastern Interconnection. The greatest growth is expected to occur in the East North Central Region, followed by the Middle Atlantic and South Atlantic Regions, while low growth is expected in the East South Central Region and negative growth in the New England Region. As Figure 3-6 indicates, the Middle Atlantic and West North Central Regions are projected to have the highest penetrations of DR at 13.3% and 10.7%, respectively, of regional peak demand in 2015 and in the future.

Figure 3-6. DR Resource Capacity as a Percent of Regional Peak Demand



Note: Since the DR Base Case assumes that DR savings grow at the same rate as peak demand in 2016-2030, DR savings as a percent of peak demand stays constant after 2015.

As shown in Figure 3-6, the Middle Atlantic Region is a major leader, as are the West and East North Central Regions in terms of near-term DR penetration and growth. This is likely due to the PJM, NYISO, and MISO markets, which encourage greater DR participation. Specific states with high DR penetrations include Pennsylvania and Florida.

In contrast, near-term growth in New England is relatively flat, and the recent capacity auction results for 2016 actually show a significant decrease in committed DR capacity from close to 1400 MW in 2015 to less than 900 MW of Real-Time Demand Response in 201637. While these results may be indicative of future trends for DR, it is too soon to know if this decrease in DR activity is due to broader market trends or characteristics particular to New England's market.

Overall, these results align with projections of dispatchable DR from NERC's 2012 LTRA and the results from FERC's recent DR survey. NERC forecasts 39.4 GW of dispatchable DR in the Eastern Interconnection in 2013[38], while this analysis estimates roughly 38.4 GW of dispatchable DR resource capacity. However, FERC's 2012 DR survey estimated the penetration of dispatchable and non-

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[37] For consistency, ISO-NE's DR resource capacity numbers for 2012-2016 are based on the Real-Time Demand Response cleared in the primary Forward Capacity Auctions, although the actual capacity that participates in the market has historically been less after reconfiguration auctions.

[38] Includes the total load-modifying and resource-side DR for FRCC, MISO, MRO-Other, NPCC, PJM, SERC, and SPP.

dispatchable DR as 64.3 GW in 2011[39], which is significantly higher than the 39.1 GW of resource capacity that Navigant estimated for 2012.

Key differences between Navigant's analysis and that of FERC include: the use of IRP data instead of self-reported data for many of the utilities; the removal of DG capacity from DR; the removal of almost 5 GW of time-based rates from the FERC data;[40] and different methods for eliminating double-counting.

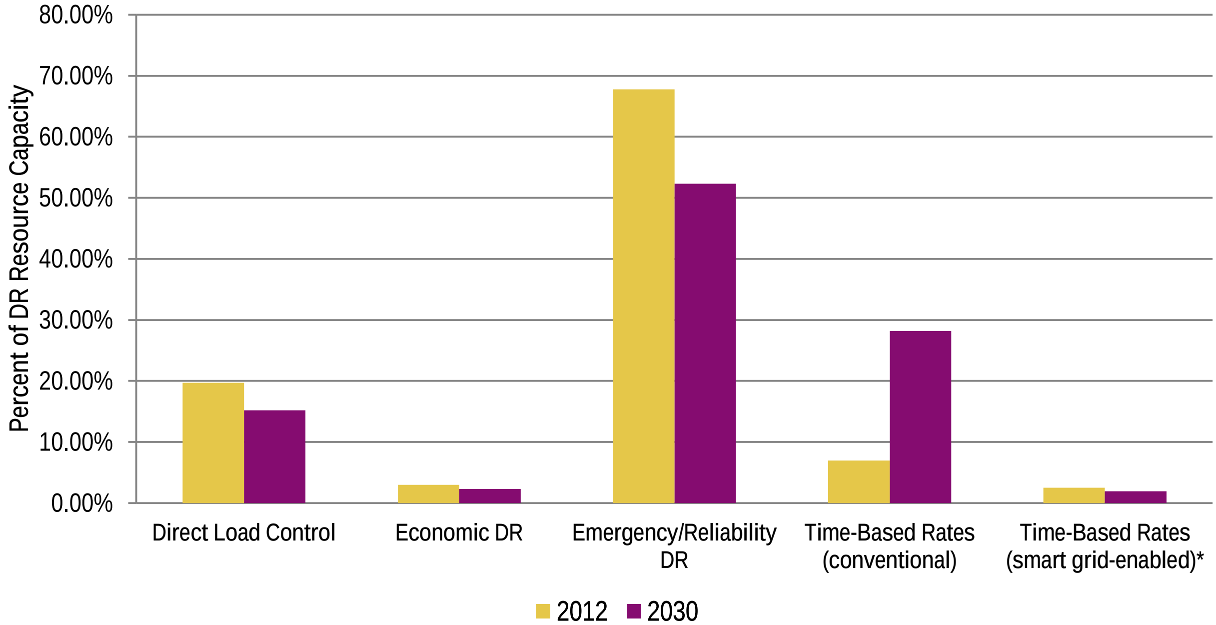
Navigant also estimated the proportions of DR resource capacity by customer sector and sub-resource category. From the data collected for this analysis, Navigant estimates that about 33% of DR resource capacity in the Base Case is from residential customers and the remaining 67% is from non-residential customers.

Of the DR sub-resource categories, Navigant found that Emergency/Reliability DR accounts for nearly 70% of existing DR resource capacity. As Figure 3-7 shows, Direct Load Control is the second largest category and accounts for almost 20% of DR in 2012. While time-based rates are currently less than 10% of the DR resource capacity, the penetration of time-based rates is expected to increase to roughly 30% of DR by 2030 primarily due to the deployment of AMI and other smart grid technologies (see additional discussion in Section 3.6). Since minimal data were available for the DR sub-resource categories beyond 2012, Navigant assumed that the proportions of the conventional DR sub-resource categories stay constant relative to one another as smart grid-enabled DR grows and conventional DR shrinks over time. This effect can be seen for 2030 in Figure 3-7.

[39] Includes the total potential peak reduction estimated for FRCC, MRO, NPCC, RFC, SERC, and SPP.

[40] Through discussions with utility staff and review of secondary resources, Navigant identified misreported data for some of the time-based rate programs for C&I customers in the FERC survey results. This data was removed from Navigant's analysis.

Figure 3-7. Percentage of DR Resource Capacity by Sub-Resource Category in 2012



* Includes time-based rate programs that require AMI meters with two-way communication capability.

Scenario Results

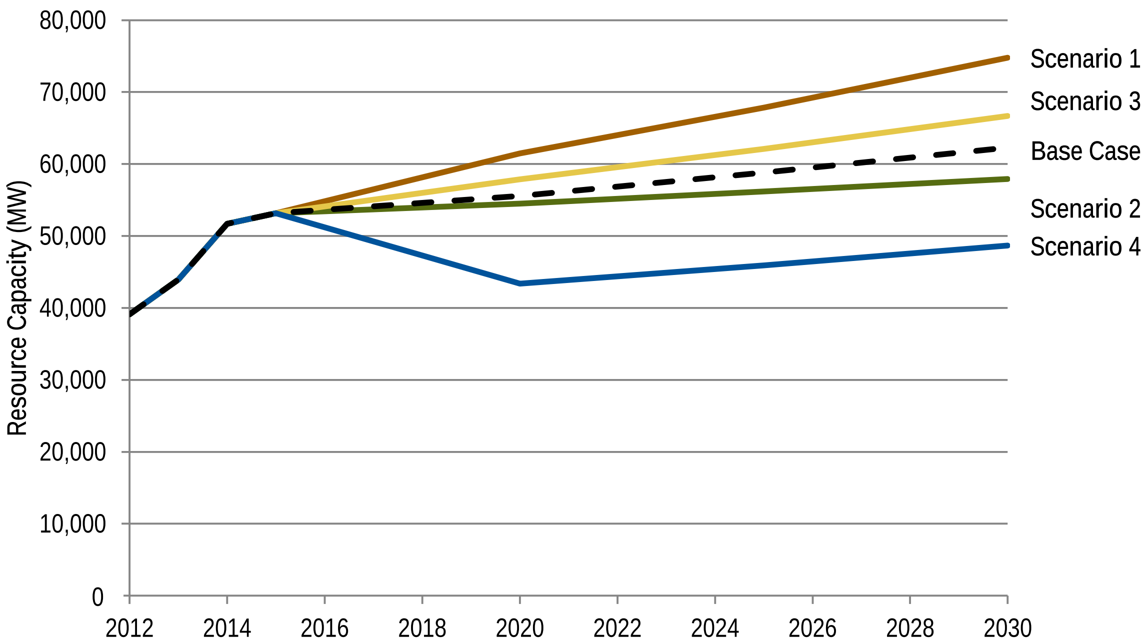
Table 3-13 presents the forecast of DR resource capacity through 2030 for the Base Case and four scenarios outlined in Section 3.2.2. The team assumed that the near-term DR capacity projected for 2012 through 2015 is the same in all scenarios because much of this capacity is already committed (e.g., in forward capacity markets, IRPs, regulatory filings, etc.) and changes in the key scenario drivers are unlikely to impact the market quickly enough to significantly affect the DR committed through 2015.

Table 3-11. Scenario Analysis of DR Resource Capacity through 2030

Scenario	Projected DR Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Base Case	39,123	43,933	51,698	53,148	55,574	58,799	62,298
Scenario 1	39,123	43,933	51,698	53,148	61,473	67,816	74,758
Scenario 2	39,123	43,933	51,698	53,148	54,476	56,175	57,937
Scenario 3	39,123	43,933	51,698	53,148	57,860	62,081	66,659
Scenario 4	39,123	43,933	51,698	53,148	43,379	45,915	48,651

Figure 3-8 presents the forecast of DR resource capacity through 2030 for the Base Case and four scenarios in graphic form. Due to the assumed favorable demand-side policies, technology advancements, and high customer acceptance, Scenario 1 (with aggressive policy goals and strong economic growth) has the largest growth in DR capacity through 2030 to 10.4% of peak demand. The next highest is Scenario 3 (with aggressive policy goals and weak economic growth), which grows to about 9.3% of peak demand in 2030 as a result of more robust demand-side policies and customer acceptance, but weaker economic activity and no other significant drivers. Scenario 2 (with strong economic growth and relaxed policy goals) is lower than the Base Case at 8.1% of peak demand in 2030 due to some increase in customer acceptance and higher load growth driving resource capacity needs, but no significant policy drivers. Scenario 4 (weak economic growth and relaxed policy goals) is also lower than the Base Case at 6.7% of peak demand in 2030 because, in the absence of supporting policies, the low load growth lead to utility resistance to new DR investments.

Figure 3-8. Scenario Analysis of DR Resource Capacity through 2030



3.3 *Study #3: Distributed Energy Storage*

Navigant forecasted the penetration of existing and planned energy storage (ES) within the Eastern Interconnection with attention to the following dimensions:

- State and
- Application (frequency regulation, load shifting, renewable integration, and deferral of transmission and distribution capacity investment).

This analysis represents a bottom-up estimate and forecast based on publicly and commercially available information. Because the sources focus on existing (2012) and near-term (2013-2015) resource capacity data, Navigant developed a set of assumptions to forecast the peak load impact. For the long-term forecast (2016-2030), a peak load impact from ES was determined and then converted into a resource capacity value. Section 3.3.2 describes these assumptions and forecasting approach.

3.3.1 Sources and Data Collection

In developing the near-term forecast for ES, Navigant leveraged prior work with government entities, utilities, and vendors. The project team used its library of several hundred reports, articles, presentations, and papers to estimate the existing and planned commercial ES installations. The primary data sources include the Navigant Energy Storage Database, the Pike Research (A Part of Navigant) Energy Storage Tracker (Q4 2012), and Energy Acuity. These data sources provide project-specific information on location, technology, capacity, duration, application, and owner of the ES unit. Section 3.3.2 describes this project-specific information.

3.3.2 Analysis Approach

The goal of this analysis is to forecast the adoption of demand-side resources, such as ES, and the associated impact on electricity demand in terms of three factors: resource capacity, annual energy impact, and peak load impact. In the context of the ES forecast, these factors are defined as follows:

- **Resource capacity** refers to installed gross capacity of ES devices;
- **Annual energy impact** refers to estimated reduction in annual electricity consumption as a result of the operation of ES devices[41]; and
- **Peak load impact** refers to the estimated reduction in generation capacity requirement to meet annual peak demand within the Eastern Interconnection as a result of the operation of ES devices.

Considerations and Identified Issues

The near-term ES projects and market applications in the Eastern Interconnection are fairly well-known and documented. However, difficulties arise in forecasting ES from 2016 through 2030 because of uncertainty in the following factors:

- Technology advancements and limitations (e.g., power, energy, and footprint),
- Location of interconnection (generation and transmission, distribution, end-user),
- Owner (utility, non-utility merchant/independent power producer, end-user),
- Regulatory structure (regulated, deregulated, partially deregulated), and
- Other (e.g., degree of automation on the grid, and permitting).

With respect to technology type, this study evaluates the following ES assets: flow batteries, flywheels, conventional and advanced lead acid batteries, lithium-ion (Li-ion) batteries, sodium-sulfur (NaS), and sodium-ion (Na-ion) batteries. Navigant did not include large-scale storage such as pumped hydro storage (PHS) and compressed air energy storage (CAES), technology demonstrations with a focus on chemistry development, or thermal storage. The large-scale technologies are not considered to be distributed demand-side resources and the technology demonstrations with a focus on chemistry development are not expected to have any impact on the grid.

[41] Navigant assumed negligible annual energy impact from ES because the majority of ES devices target applications with other primary foci. In most cases, the use of energy storage will increase energy requirements due the inherent losses in storage systems.

Additionally, there is significant interest in vehicle-to-grid (V2G) applications as an opportunity for the utility to take advantage of the ES capacity in electric vehicles (EVs). While this may be possible in the future as EV penetration increases, smart grid assets are implemented, and business models develop, based on previous investigations performed for the DOE and utilities, Navigant considers V2G applications as opportunities that are beyond the timeframe of this study.

Base Case Forecast Methodology

Existing ES (2012) and Near-Term ES Forecast (2013-2015)

The methodology for estimating the existing market penetration of ES and the near-term forecast through 2015 included a review of both existing studies and publicly available data.

The first step in estimating the ES market was to understand the environment within which ES devices would operate. This includes: assets that will be deployed; the owners of those assets; the type of markets in which they will be deployed; and the locations of the deployments on the grid. Table 3-12, Table 3-13, and Table 3-14 list and describe the criteria used in the analysis pertaining to location, regulatory structure, and owner, respectively. The device's application (e.g., renewable energy integration, peak shifting, and frequency regulation) and resulting impact(s) depend greatly on these criteria.

Table 3-12. ES Location Definitions

Location Subcategory	Definition
Generation & Transmission (G&T)	Includes ES devices located between the generator and the power transformer at a step-down distribution substation.
Distribution	Includes the following: • ES devices located between a distribution step-down substation and the end-user. Typical voltages in this part of the grid range from 12 to 138 kilovolts. • ES devices located in the step-down substation and located on the secondary side of the transformer. • ES deployed in a "community energy storage" configuration.
End-User	Includes ES devices located within the end-user premises, as opposed to the utility-side of the meter. The end-user is the person or entity that uses energy, as distinct from, for example, entities that engage in wholesale energy transactions or purchases made by a landlord or other "distributor."

Table 3-13. Definitions of Regulatory Structure

Regulatory Structure Subcategory	Definition
Regulated	A market in which utilities are vertically integrated, incorporating most elements of electric delivery and service into a single company.
Deregulated	A market in which retail services, delivery (transmission and distribution) and power generation have been separated, allowing for independent power producers and other suppliers to participate in the market. This structure encourages competition at the retail energy service level and wholesale energy supply levels.
Partially Deregulated	A hybrid of the two markets above-defined.

Table 3-14. ES Owner Definitions

Owner Subcategory	Definition
Utility	An owner that maintains and operates a local transmission and/or distribution grid, such as an investor-owned utility, municipal utility, or electric cooperative.
Non-Utility Merchant/ Independent Power Producer	An owner that can independently deploy generation and ES assets for wholesale market participation or contracts with utilities or end users.
End-User	An owner that is primarily an end-user of electricity.

As the announcement, funding, construction, and full deployment of an ES project requires several years of effort, Navigant assumed that the near-term ES capacity projected for 2013 through 2015 is already known from the literature collected. Also from the literature, the peak load impact was estimated based on technology (discharge duration) and targeted application. In the near-term, the most appealing application for ES is frequency regulation (ancillary services).

Long-Term ES Forecast (2016-2030)

From 2016 through 2030, ES will increasingly target long-duration applications. The long-term forecast of ES focuses on three applications: renewables integration[42]; load shifting; and deferral of transmission and distribution capacity investment. Navigant first estimated the market requirement for each of the three applications in terms of the percentage of annual peak load. The team then estimated the percentage of this market requirement that distributed ES will address. Table 3-15 describes the assumptions made for each application in order to calculate peak load impact and subsequently, resource capacity.

Table 3-15. ES Application Assumptions

ES Application	Market Requirement for Application	% of the Requirement addressed by ES
Frequency Regulation & Renewable Integration	2% of annual peak load	2.5% to 7.5%
Load Shifting	100% of annual peak load	0.03% to 0.08%
Deferral of Transmission and Distribution Capacity Investment	1% of annual peak load	1% to 5%

Note: The percent varies by year.

Moreover, to convert from peak load impact to resource capacity, Navigant assumed certain duration factors for each application based on today's ES technologies and their discharge rates. Table 3-16 states these duration factors.

[42] Renewable integration application includes services such as energy firming and shifting. For this analysis, frequency regulation and renewables integration were combined into one category.

Table 3-16. Duration Factor for Adjusting ES Peak Demand Impact to Resource Capacity

Application	Duration Factor
Frequency Regulation & Renewable Integration	50%
Load Shifting	75%
Deferral of Transmission and Distribution Capacity Investment	80%

Scenario Analysis Approach

For the scenario analysis of ES, the team adjusted the market size for ES applications and the duration factors to account for the changes in scenario driver conditions. The team assumed that the following drivers were particularly influential to the adoption of ES:

- **Energy Policies that Support Demand-Side Resources:** One of the primary drivers for ES is expected to be state, regional, and Federal policy supporting ES, particularly regulations that guide resource participation in organized markets and market rules. For example, depending on the policies in place, utilities could consider ES as either a transmission and distribution asset or a generation asset. Policies supporting renewables (e.g., Renewable Portfolio Standards) may also indirectly affect ES resource capacity because ES can address the intermittency of wind and solar generation.
- **Technology Advancement:** Advancements in storage chemistries, decreases in material costs, and increases in cycle life as these technologies become more mature are expected to play a significant role in achieving greater market penetration. These improvements could lead to cost reductions of 50% or greater over this timeframe, resulting in several applications becoming more attractive.

3.3.3 Results

Base Case Results

Table 3-17 presents the forecast of ES resource capacity through 2030, aggregated by U.S. Census Region.

Table 3-17. Projected ES Resource Capacity by U.S. Census Region

U.S. Census Division	U.S. Census Region	Projected ES Resource Capacity (MW)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	2	4	4	4	46	98	163
	Middle Atlantic	38	39	71	93	115	242	396
Midwest	East North Central	5	7	7	7	164	345	566
	West North Central [a]	1	1	1	1	110	231	378
South	South Atlantic	43	43	43	43	310	661	1,091
	East South Central	0	0	0	0	110	236	391
	West South Central [a, b]	0	0	0	0	95	200	327
TOTAL		88	93	125	149	951	2,013	3,312

a. *Portions of both Montana and New Mexico fall within Eastern Interconnection territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

The market for ES is in its early stage of development and will remain modest over the next decade. Growth is slow in the near-term while demonstration projects are commissioned and empirical data is gathered on the operations and maintenance requirements and total lifecycle costs. Navigant forecasts that growth in ES adoption will begin to gain traction following 2015 as the current demonstration projects validate the performance of ES technologies. Furthermore, Navigant expects additional technological advances and cost reductions to accelerate the development of the ES market.

From these capacity values, Navigant estimated peak load impact. Table 3-18 presents the forecasted peak load impact from ES resources. Annual energy impact is not presented here, since as discussed in Section 3.3.2, a negligible change in annual energy impact is assumed for ES.

Table 3-18. Projected ES Peak Load Impact by U.S. Census Region

U.S. Census Division	U.S. Census Region	Projected ES Peak Load Impact (MW)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	1	2	2	2	27	58	97
	Middle Atlantic	15	15	23	26	68	142	235
Midwest	East North Central	5	7	7	7	96	203	337
	West North Central [a]	1	1	1	1	65	136	225
South	South Atlantic	43	43	43	43	182	388	649
	East South Central	0	0	0	0	65	138	233
	West South Central [a, b]	0	0	0	0	56	118	195
TOTAL		64	68	76	79	558	1,182	1,970

a. *Portions of both Montana and New Mexico fall within Eastern Interconnection territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

Refer to Appendix A for a state-by-state breakdown forecast of resource capacity and peak load impact.

Scenario Results

Table 3-19 presents the forecast of ES resource capacity through 2030 for the Base Case and four scenarios outlined in Section 3.3.2. The team assumed that the near-term ES capacity projected for 2012 through 2015 is the same in all scenarios because to announce, fund, construct, and fully deploy an ES project requires several years of effort, and changes in the key scenario drivers are unlikely to impact the market quickly enough to significantly affect ES through 2015.

Table 3-19. Scenario Analysis of ES Resource Capacity through 2030

Scenario	Projected ES Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Base Case	88	93	125	149	951	2,013	3,312
Scenario 1	88	93	125	149	1,640	3,472	5,720
Scenario 2	88	93	125	149	951	2,013	3,312
Scenario 3	88	93	125	149	1,426	3,019	4,969
Scenario 4	88	93	125	149	713	1,510	2,484

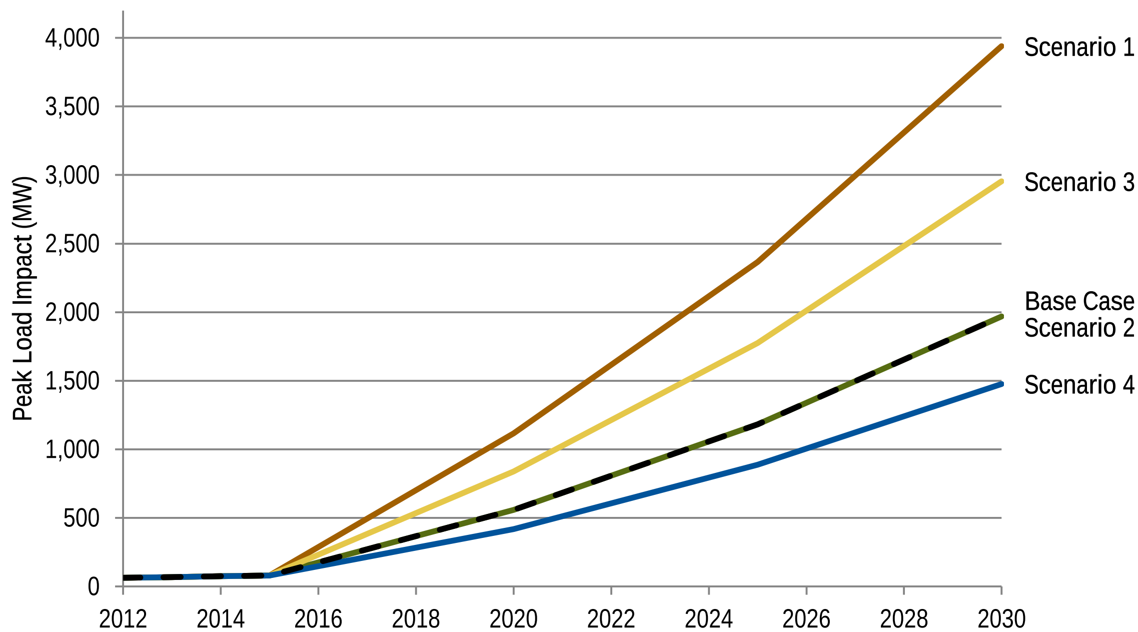
Scenario 1 (with aggressive policy goals and strong economic growth) has the largest growth in ES capacity through 2030, as a result of the assumed favorable demand-side policies and technology advancements. The next highest is Scenario 3 with aggressive policy goals and weak economic growth. Scenario 2 (with strong economic growth, relaxed policy goals, and no significant technology advancement) is the same as the Base Case, as a result of higher load growth driving resource capacity needs, but no significant policy drivers or technology advancement. Scenario 4 (weak economic growth and relaxed policy goals) is lower than the Base Case because, in the absence of supporting policies and advancement in technologies, the low load growth leads to utility resistance to new ES investments.

Table 3-20 and Figure 3-9 present the forecast of ES peak load impact through 2030 for the Base Case and four scenarios.

Table 3-20. Scenario Analysis of ES Peak Load Impact through 2030

Scenario	Projected ES Peak Load Impact (MW)						
	2012	2013	2014	2015	2020	2025	2030
Base Case	64	68	76	79	558	1,182	1,970
Scenario 1	64	68	76	79	1,117	2,365	3,939
Scenario 2	64	68	76	79	558	1,182	1,970
Scenario 3	64	68	76	79	838	1,774	2,954
Scenario 4	64	68	76	79	419	887	1,477

Figure 3-9. Scenario Analysis of ES Peak Load Impact through 2030



3.4 *Study #4: Distributed Generation with Fossil Fuels*

Navigant forecasted the penetration of existing and planned fossil-fueled distributed generation (DG-F) within the Eastern Interconnection with attention to the following dimensions:

- State,
- Owner type (commercial, industrial, and utility), and
- Fuel type (gas, oil, coal, and other).

This analysis represents a bottom-up estimate and forecast based on publicly and commercially available information. As the majority of data garnered relates to historical installations, Navigant developed a set of assumptions to forecast the deployment of DG-F capacity and convert that forecast into annual energy impact and peak load impact. Section 3.4.1 describes these assumptions and forecasting approach.

3.4.1 Sources and Data Collection

To examine the state-by-state capacity over time, current and historical data were collected from Platt's World Electric Power Plant (WEPP) Database and ICF International's Combined Heat and Power (CHP) Installation Database. Platt's WEPP Database is a global inventory of electric power generating units of all sizes. It includes information such as ownership, location, and engineering design data for power plants and technologies operated by regulated utilities, private power companies, and industrial or commercial autoproducers[43]. The ICF's CHP Database is supported by both the U.S. Department of Energy and Oak Ridge National Laboratory and includes state-specific CHP units and details such as

[43] Platt's WEPP descmeth document.

location, fuel type, application, and prime mover. No other reliable sources of installed DG capacity were identified.

Platt's Database was selected as the primary source for this information because it is more comprehensive and detailed than any other source investigated; and Navigant incorporated the ICF Database into the analysis to increase the comprehensiveness of CHP data. The team used the following criteria when discerning which units to include in the analysis:

1. Units in the Eastern Interconnection;
2. Units with a capacity[44] between and including 1 and 20 MW;
    a. 1 MW serves as a lower boundary because while there are many DG-F units of smaller capacity, the quality of data is low due to lack of complete reporting[45]. As it is very difficult to get an accurate estimation of their aggregated capacity, those small units were excluded from the analysis to maintain a higher quality of data.
    b. 20 MW is the upper boundary because larger units exhibit characteristics commonly associated with centralized rather than distributed generation.
3. Units that are currently operating, planned, or retired between 1970 and 2011; and
4. Units operating on coal, gas, or oil-based fossil fuels
    a. Beyond coal, gas, and fuel oil, the team considered a multitude of miscellaneous fuel types, including jet fuel, kerosene, coke oven gas, and blast-furnace gas[46]. However, there were no units powered by those miscellaneous fuels that met the other criteria.
    b. The team excluded generation units powered by non-fossil fuels, such as renewables and wastes.

3.4.2 Analysis Approach

The goal of this analysis is to forecast the adoption of demand-side resources, such as DG-F, and the associated impact on electricity demand in terms of three factors: resource capacity; annual energy impact; and peak load impact. In the context of the DG-F forecast, these factors are defined as follows:

- **Resource capacity** refers to installed gross capacity of DG-F units physically available to provide deliverable power to load;
- **Annual energy impact** refers to estimated annual electricity generation from operational DG-F units; and
- **Peak load impact** refers to the estimated reduction in generation capacity requirement to meet annual peak demand within the EI as a result of the operation of DG-F units.

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[44] This is gross capacity according to the sources referenced.
[45] Platt's WEPP Database.
[46] Platt's WEPP Database includes other fuel categories that are fossil fuels, including: blast-furnace gas, bitumen, coal syngas, gasified petroleum coke, coal, coke oven gas, coke, coal-water mixture, ethanol, flare gas or wellhead gas, gas, gasoil, jet fuel, kerosene, liquefied natural gas, liquefied petroleum gas, naphtha, gasified crude oil or refinery bottoms or bitumen, fuel oil, orimulsion, petroleum coke synthetic gas, oil shale, and tar sands.

Considerations and Identified Issues

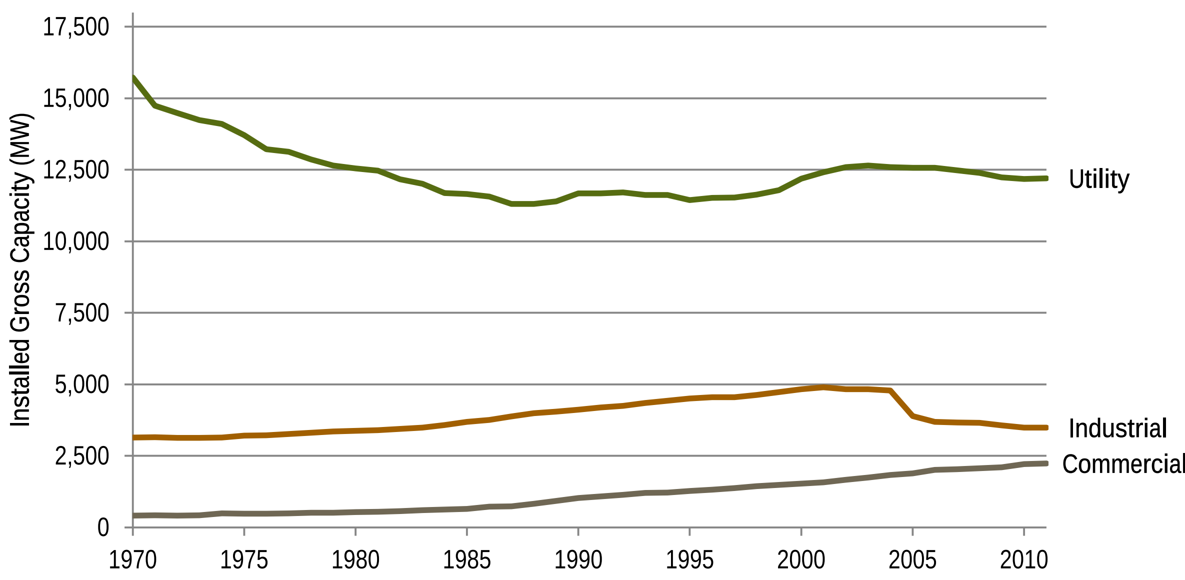
The most significant challenge associated with the analysis of DG-F was the reconciliation of the two data sources: Platt's WEPP Database and the ICF CHP Installation Database. In merging the two databases, the team identified multiple duplicate listings with inconsistent data, i.e., some units were listed in both databases with different gross capacity values, fuel types, or installation years. In such instances, the information given in Platt's WEPP Database was used because it contains more comprehensive and detailed information on each unit.

With the exception of a small number of planned units, Platt's WEPP and the ICF Databases only include historical and current capacity values. Therefore to determine future values, the team designed an approach to use state-level historical installation data as an input and forecast deployment out to 2030 based on a unit's business type and fuel type. The following section details the breakdown of business type and fuel type.

Base Case Forecast Methodology

In order to establish the Base Case, it was necessary to get an accurate view of the historical data. Both Platt's and the ICF Database include two key attributes of each DG-F unit: the business type of the unit's owner and its fuel type. Figure 3-10 shows the capacity based on business type from 1970 through 2011.

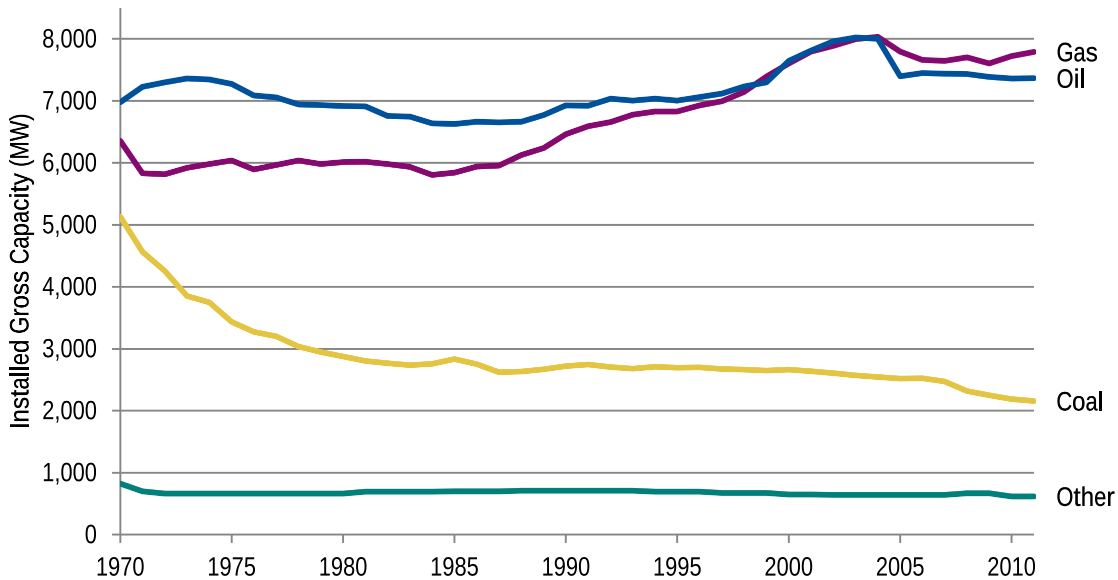
Figure 3-10. Historical DG-F Capacity for All Business Types



As Figure 3-10 indicates, there are historical trends distinctive to each business type. While utility-owned units have accounted for the majority of the total DG-F capacity within the entire Eastern Interconnection, that capacity has decreased over time. On the other hand, the capacity of the units owned by commercial entities has steadily increased over the past 40 years.

There is a similar need for separation in terms of fuel type. Figure 3-11 shows the historical trends of distributed generation with respect to a given fuel type. "Other" fuel includes jet fuel, kerosene, coke oven gas, and blast-furnace gas.

Figure 3-11. Historical DG-F Capacity for All Fuel Types



Oil-fired generators had the largest capacity from 1970 through 2004, when they were surpassed by gas-fired generation. Coal-fired distributed generation exhibited a rapid decrease in capacity from 1970 to 1980; and since then it has continued to decline, but at a slower rate due to retirements driven by rising costs of environmental compliance.

As the historical trends for installed capacity associated with different business types and fuel types are sufficiently unique, the team subdivided historical capacity data into twelve unique combinations of business types (i.e., utility, commercial, and industrial) and fuel types (i.e., coal, gas, oil, and other), to segment the forecasting process. The data was further segmented at the state-level to reflect market and regulatory considerations unique to each state.

Within each state, the team determined the Base Case resource capacity of each business type-fuel type (BT-FT) combination in 2012, 2013, 2014, and 2015 using the previous five-year rate-of-change in capacity. An additional growth factor was also applied to certain BT-FT combinations that will likely follow different growth trends in the next four years than they have in the last five. These additional growth factors consider economic, legislative, and market influences. For example, the team expects that the capacity of coal-fueled distributed generation will decline from 2011 due to factors such as "sustained low natural gas prices, higher coal prices, slow growth in electricity demand, and the implementation of Mercury and Air Toxics Standards and Cross-State Air Pollution Rule"[47]. Conversely, the adoption of gas-fueled units will likely accelerate due to "recent technological advances and

[47] US EIA. "Annual Energy Outlook 2012: with projections to 2035". June 2012. Pg 45. (www.eia.gov/forecasts/aeo)

continued drilling of shale gas reserves plays with high concentrations of natural gas liquids and crude oil" which result in low gas prices and the US becoming a net gas exporter[48].

To forecast the capacity from 2016 to 2030, a similar approach was taken. However, this longer term forecast was based on the 15-year trend going back to 1996 rather than looking at the capacity trend from 2006 through 2011. Again, an additional growth factor was applied to certain BT-FT combinations to reflect expected variance in trend from the historical values. For example, the additional growth factors for both gas-fueled units operated by commercial and industrial owners were increased to accelerate the slower growth that has been exhibited in these two areas over the past five years.

After forecasting the Base Case capacity to 2030, the team was able to calculate the yearly amount of electricity generated by these distributed power sources. To do this, the team worked with Navigant's industry experts to estimate net capacity factors for each of the BT-FT combinations. These net capacity factors reflect averages of both how often and at what percentage of capacity a specific type of unit will be generating power. Table 3-21 summarizes the range of capacity factors applied to different BT-FT combinations.

Table 3-21. DG-F Net Capacity Factors by Business and Fuel Type

Fuel Type	Net Capacity Factor by Business Type		
	Commercial	Industrial	Utility
Coal	30%	50%	50%
Gas	15%	40%	25%
Oil	7%	10%	10%
Other	5%	50%	5%

Finally, the peak load impact was calculated by using the total capacity for a given year in a given state and applying an availability factor of 0.9, which accounts for units that do not always operate at peak or may be undergoing maintenance during a peak event.

Scenario Analysis Approach

For the scenario analysis of DG-F, the team adjusted the additional growth factors to account for the changes in scenario driver conditions. The team assumed that the following drivers were particularly influential to the adoption of DG-F:

- **Retail Electricity Prices:** The primary incentive for commercial and industrial entities to install a DG unit is to reduce utility costs. Thus, changes in the retail electricity price would directly affect their decisions on whether or not to adopt DG-F.
- **Natural Gas Prices:** Retail natural gas prices are a critical consideration when commercial and industrial entities evaluate the cost-effectiveness of natural gas-fired DG units.

[48] US EIA. "Annual Energy Outlook 2012: with projections to 2035". June 2012. Pg 3. (www.eia.gov/forecasts/aeo)

- **Economic Growth:** Service reliability is one of the key reasons why large utility customers adopt DG-F. Changes in economic growth typically impact load growth. Therefore, to ensure service reliability, large commercial and industrial customers may choose to install DG-F units.

Beyond these three drivers, changes in relevant policies (e.g. RPS, and greenhouse gas regulations) may discourage some potential DG owners from adopting resources powered by fossil fuel. The team assumed that changes in technological advancement and customer adoption will not have significant impact on the forecast.

3.4.3 Results

Base Case Results

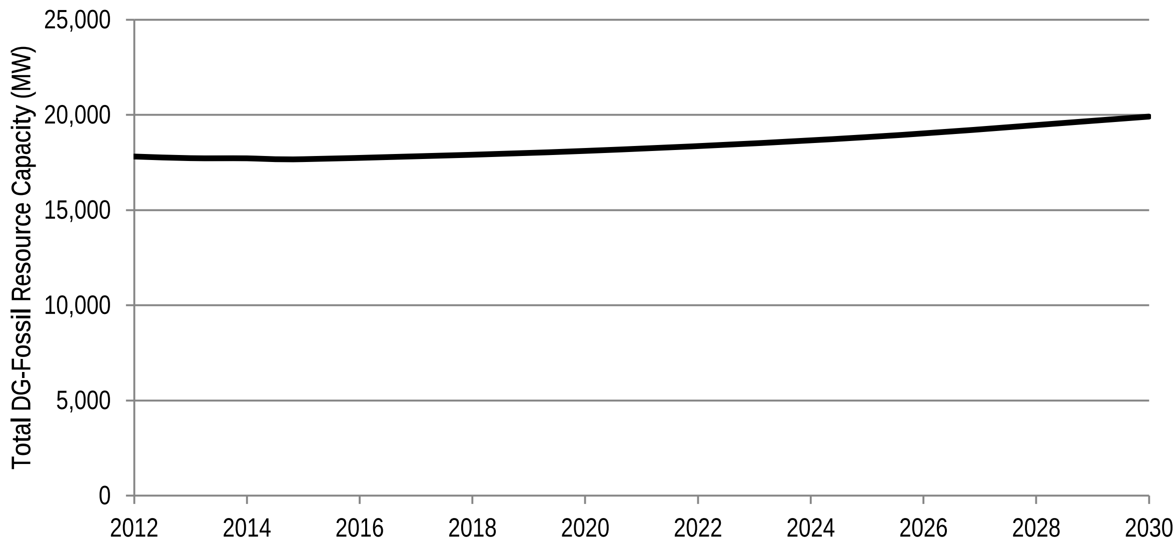
Based on the forecast, the overall level of peak load impact associated with DG-F will slightly decrease through 2015 due to retirements of older oil-fueled and coal-fueled units being of larger total capacity than the new additions. After 2015, the impact starts to increase, driven primarily by new adoption in the commercial and industrial sectors. Table 3-22 presents the forecast of DG-F resource capacity through 2030 aggregated by U.S. Census Region, and Figure 3-12 shows the trend through 2030.

Table 3-22. Projected DG-F Resource Capacity by U.S. Census Region

U.S. Census Division	U.S. Census Region	Projected DG-F Resource Capacity (MW)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	1,412	1,446	1,531	1,571	1,729	1,927	2,172
	Middle Atlantic	2,775	2,771	2,776	2,792	2,850	2,952	3,101
Midwest	East North Central	4,527	4,458	4,389	4,327	4,310	4,403	4,644
	West North Central [a]	4,007	3,999	3,972	3,946	4,036	4,147	4,273
South	South Atlantic	3,145	3,101	3,091	3,066	3,046	3,061	3,113
	East South Central	856	857	859	861	933	1,015	1,109
	West South Central [a b]	1,089	1,094	1,099	1,107	1,204	1,327	1,495
TOTAL		17,811	17,725	17,718	17,671	18,107	18,832	19,909

a. *Portions of both Montana and New Mexico fall within Eastern Interconnection territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

Figure 3-12. Projected DG-F Resource Capacity through 2030



Refer to Appendix A for state-by-state breakdown of the resource capacity forecast, and to Appendix D for the state-level aggregate annual growth rate of DG-F resource capacity.

From these capacity values, Navigant then estimated annual energy impact by applying the respective net capacity factor and for a given year, aggregating the individual results across the state. Peak load impact was estimated in a similar manner, except the availability factor was directly applied to a state's total capacity in a given year. Table 3-23 and Figure 3-13 present the forecasted annual energy impact.

Table 3-23. Projected DG-F Annual Energy Impact by U.S. Census Region

U.S. Census Division	U.S. Census Region	Projected DG-F Annual Energy Impact (GWh/yr)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	2,106	2,202	2,410	2,517	2,978	3,527	4,177
	Middle Atlantic	4,076	4,070	4,099	4,154	4,339	4,585	4,899
Midwest	East North Central	9,803	9,583	9,366	9,173	8,807	8,750	9,151
	West North Central [a]	7,378	7,360	7,319	7,279	7,421	7,634	7,890
South	South Atlantic	4,982	4,936	4,958	4,963	5,109	5,322	5,607
	East South Central	2,686	2,691	2,696	2,701	2,891	3,115	3,377
	West South Central [a b]	2,826	2,860	2,895	2,933	3,283	3,708	4,255
TOTAL		33,857	33,702	33,742	33,720	34,828	36,642	39,355

a. *Portions of both Montana and New Mexico fall within Eastern Interconnection territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

Figure 3-13. Projected DG-F Annual Energy Impact through 2030

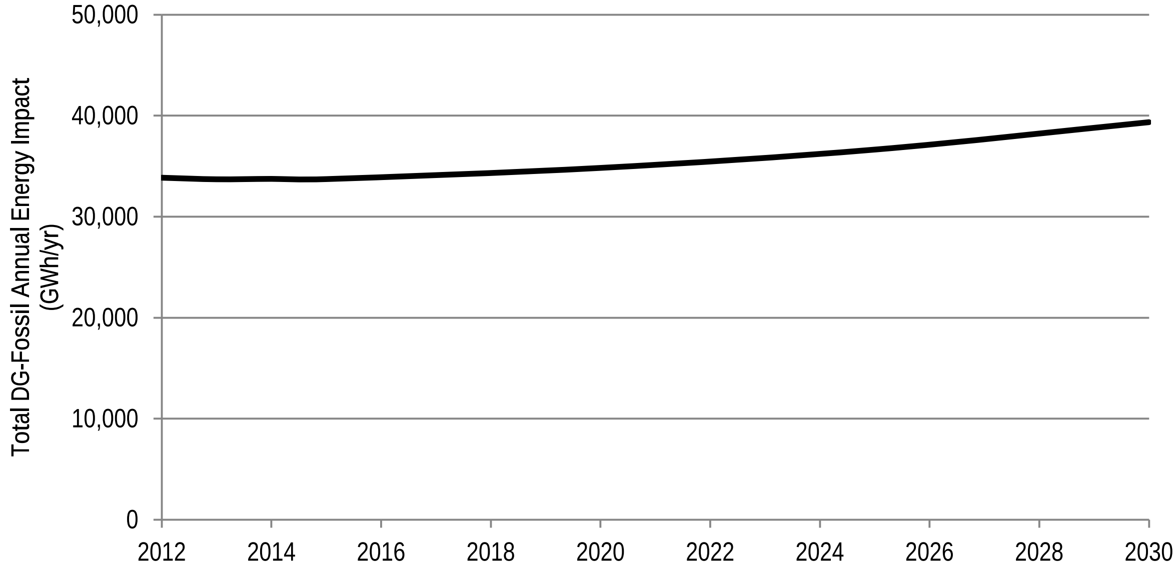


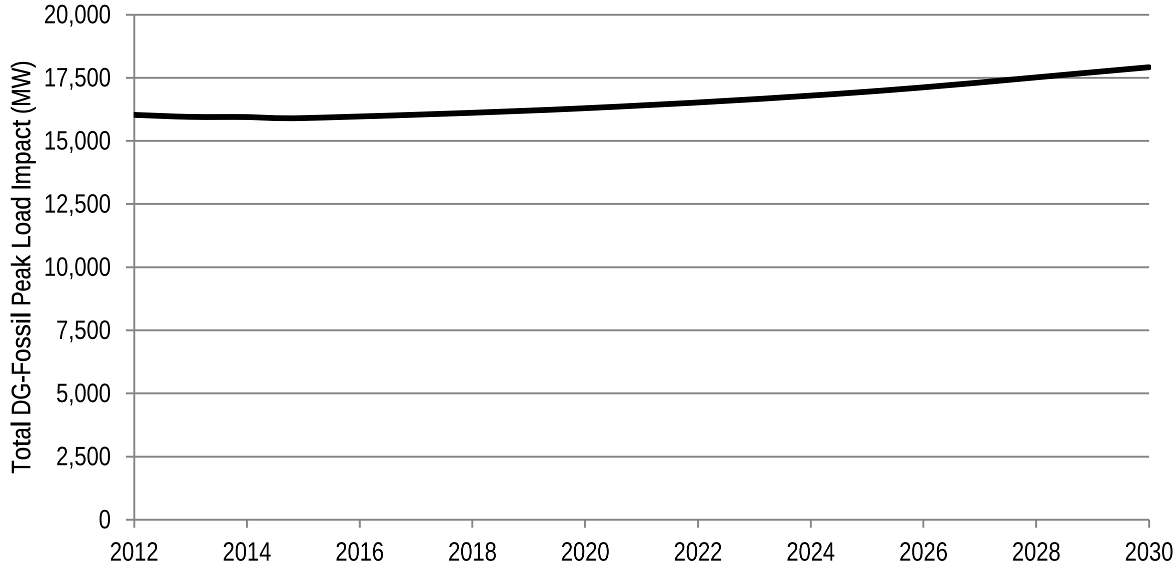
Table 3-24 and Figure 3-14 present peak load impact of forecasted DG-F resources.

Table 3-24. Projected DG-F Peak Load Impact by U.S. Census Region

U.S. Census Division	U.S. Census Region	Projected DG-F Peak Load Impact (MW)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	1,271	1,301	1,377	1,414	1,556	1,735	1,955
	Middle Atlantic	2,498	2,494	2,498	2,513	2,565	2,656	2,791
Midwest	East North Central	4,074	4,012	3,950	3,895	3,879	3,963	4,180
	West North Central [a]	3,607	3,599	3,575	3,551	3,632	3,733	3,846
South	South Atlantic	2,830	2,791	2,782	2,760	2,741	2,755	2,802
	East South Central	770	772	773	775	840	913	998
	West South Central [a b]	980	985	990	996	1,083	1,194	1,346
TOTAL		16,030	15,953	15,946	15,904	16,296	16,949	17,918

a. *Portions of both Montana and New Mexico fall within Eastern Interconnection territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

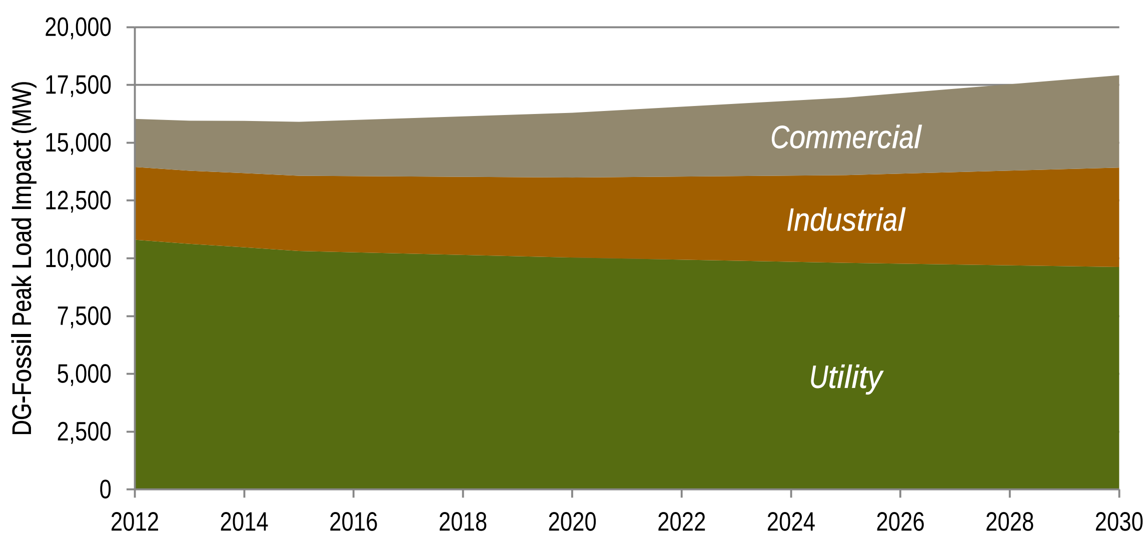
Figure 3-14. Projected DG-F Peak Load Impact through 2030



Refer to Appendix A for state-by-state breakdown of the annual energy impact and peak load impact forecasts.

Upon further examination of the peak load impact forecast, two additional interesting trends emerge. First, one would expect a shift in the breakdown of adoption across business types. While the forecast shows that the DG-F units owned by the utility sector will continue to account for the majority of the total DG-F capacity (and thus peak load impact) through 2030, the utility sector's share will concurrently continuously decline. Figure 3-15 breaks down the forecast of peak demand impact by business type.

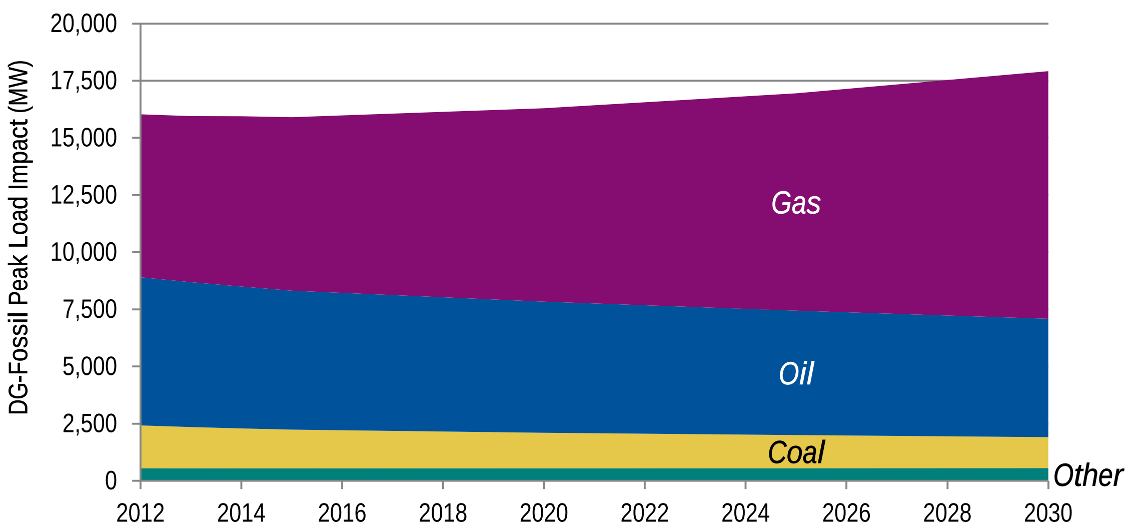
Figure 3-15. Projected DG-F Peak Load Impact by Business Type



Due to the operation of DG units at commercial and industrial facilities likely being prioritized based on the needs of the facility, they may not be available to be called upon during a peak event. Therefore, this shift in ownership could be significant with regard to peak load impact. However, if one assumes that price signals will provide adequate incentives to these commercial and industrial facilities, urging them to use their own generation during peak times, these units should still have an impact on the peak load.

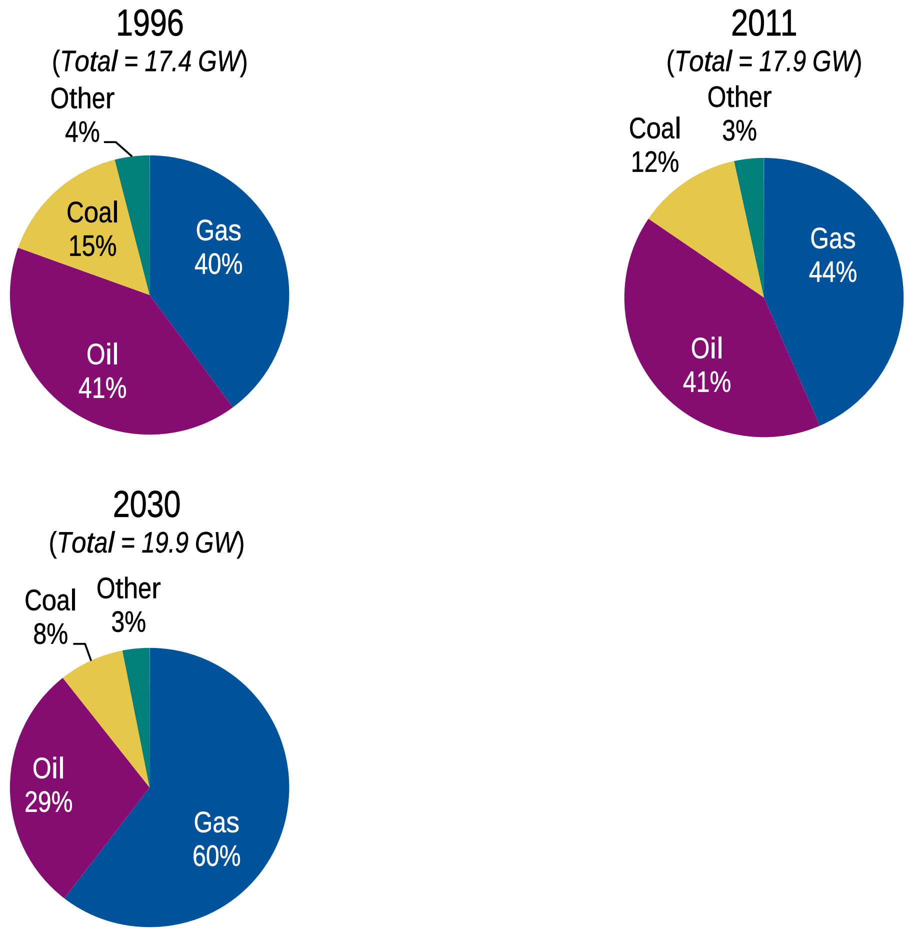
The second trend to note is the strong growth of gas-fired DG units. As Figure 3-16 shows, the peak demand impact for both coal- and oil-fired units are forecasted to decline steadily through 2030. Conversely, gas-fired units have a strong upward trend beginning in 2011, and significant overall growth in the long-term. This difference in the rates of change can likely be attributed to the relatively low cost of gas and criteria pollutant emissions associated with natural gas when compared to other fossil fuels.

Figure 3-16. Projected DG-F Peak Load Impact by Fuel Type



Given the strong growth in adoption of gas-fired DG units, the team forecasts that the relative share of gas-fired units within overall DG-F adoption will increase through 2030. Figure 3-17 presents the change in the ratio of fuels used to power DG-F units at three points through the timeframe of this forecast: 1996, which represents the earliest data points used to estimate forecasted rate of growth; 2011; and 2030.

Figure 3-17. Historical and Projected Ratios of DG-F Fuel Types in 1996, 2011, and 2030



While the ratios remain similar from 1996 to 2011, there is a slight decrease in percentage of coal capacity which corresponds to an increase in gas capacity. However, by 2030, both coal and oil capacities have decreased even further, resulting in a significant increase in gas capacity.

Scenario Results

With respect to the Base Case, in Scenario 1 (with strong economic growth and aggressive policy goals), there is a higher near-term growth rate for gas-fired DG, while oil and coal-fired DG decrease by the same rate in both the near and long-term. The team predicts this outcome as there will likely be impetus for consumers to increase gas-fired DG and decrease other DG-F to comply with the stricter GHG regulations. Additionally, in the long-term, there will be a lower total DG-F capacity, which may potentially be off-set by the increased adoption of DG-R.

In Scenario 2 (with strong economic growth and relaxed policy goals), the near-term growth rate of gas-fired DG substantially increases over the Base Case values, and slightly less so in the long-term. This is due to economic growth, which will favor the installation of additional DG units. Many of these DG units will likely be gas-fired due to the country's increasing interest in natural gas.

Scenario 3 (with weak economic growth and relaxed policy goals) predicts a slower growth for gas-fired DG relative to the Base Case. However, the gross capacities of coal- and oil-fired DG under this scenario decrease at a faster pace when compared to the Base Case. This is due to a similar need for DG, yet as more emphasis is being put on renewables, while gas will still increase, there will be an overall decrease in DG-F.

Scenario 4 (with weak economic growth and relaxed policy goals) parallels the Base Case's calculations as there are no drivers that would influence the current trends in DG-F.

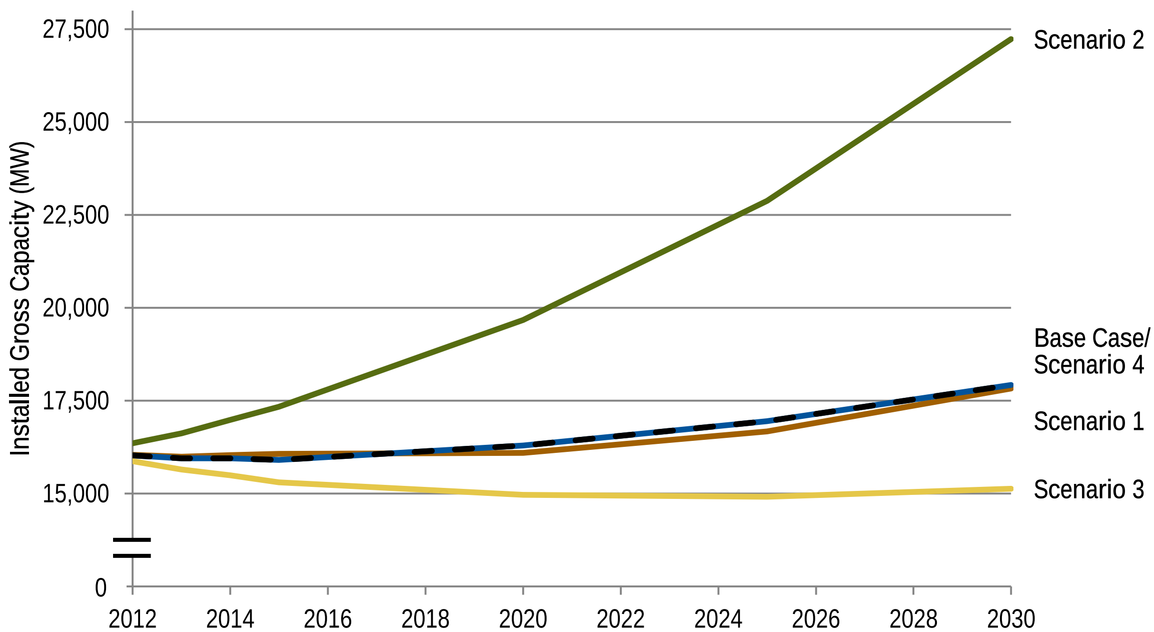
Table 3-25 represents the forecast of DG-F peak load impact through 2030 for the Base Case and the four scenarios.

Table 3-25. Scenario Analysis of DG-F Peak Load Impact through 2030

Scenario	Projected DG-F Peak Load Impact (MW)						
	2012	2013	2014	2015	2020	2025	2030
Base Case	16,030	15,953	15,946	15,904	16,296	16,949	17,918
Scenario 1	16,041	15,994	16,037	16,066	16,097	16,674	17,827
Scenario 2	16,352	16,619	16,981	17,339	19,675	22,876	27,231
Scenario 3	15,875	15,645	15,489	15,300	14,965	14,911	15,134
Scenario 4	16,030	15,953	15,946	15,904	16,296	16,949	17,918

Figure 3-18 presents the forecast of DG-F peak load impact through 2030 in comparison to the Base Case. Scenario 2 exhibits the highest impact, whereas Scenario 4 has the smallest.

Figure 3-18. Scenario Analysis of DG-F Peak Load Impact through 2030



3.5 Study #5: Distributed Generation with Renewable Resources

Navigant forecasted the penetration of existing and planned renewable distributed generation (DG-R) within the Eastern Interconnection with attention to the following dimensions:

- Location (state and corresponding reliability region) and
- Resource category (biomass, solar, hydropower, and wind).[49]

This analysis is derived from an estimate and forecast based on publicly and commercially available information. As the majority of data garnered relates to historical installations, Navigant developed a set of assumptions to forecast the deployment of DG-R capacity. Using publicly available information, the team converted the DG-R nameplate capacity forecast into annual energy impact and peak load impact. Sections 3.5.1 and 3.5.2 describe these assumptions and forecasting approach.

3.5.1 Sources and Data Collection

To examine the state-by-state capacity over time, current and historical data were collected from SNL Financial, Interstate Renewable Energy Council (IREC), and American Wind Energy Association (AWEA). Annual growth percentages were collected from National Renewable Energy Laboratory (NREL) and U.S. Energy Information Administration (EIA).

SNL Financial's Project Database was selected as the primary source for current and historical biomass and hydropower plant data as it was the most complete and detailed source available for those two types of distributed generation. Moreover, Navigant considers the SNL Database to be more comprehensive for distributed generation than Platt's Database or the Form EIA-861 data files. The SNL Database was filtered to include all operating biomass and hydropower plants in the Eastern Interconnection that have a capacity of 10 MW or less. Fuel cell plants were filtered out of the biomass project list, but all other types of biomass, such as biogas and landfill gas, were included in this analysis.

IREC's *U.S. Solar Market Trends 2011* report was selected as the primary source for current solar capacity by state. Reports dating back to 2006 were used to understand the historical trends in solar photovoltaics (PV). In its primary research, IREC obtained state data for grid-connected PV installations from three primary sources: state agencies, organizations administrating state incentive programs, and utility companies. In its secondary research, IREC collaborated with two other PV report-generating efforts: quarterly solar installation reports by GreenTech Media (GTM) and the Solar Energy Industries Association (SEIA) and annual survey-based reports on solar installations by utility by the Solar Electric Power Association (SEPA). Since IREC's reports include all sizes of solar plants, the SNL Database was used to identify any plants in the Eastern Interconnection over 10 MW in capacity. Large solar projects in Florida, New Jersey, New York, North Carolina, and Ohio were subtracted from IREC's state capacity totals.

AWEA's Project Database was selected as the primary source for current solar capacity by state. This source is generally considered the most complete database of existing U.S. wind projects. To isolate the

[49] Geothermal was not included in this analysis because there are no planned or existing geothermal plants in the Eastern Interconnection according the SNL Financial database.

distributed generation capacity, Navigant filtered out all projects with a capacity greater than 10 MW and for each state in the Eastern Interconnection summed the capacities of projects less than 10 MW.

In order to project the Base Case data out to 2030, annual growth rates were averaged from NREL's 2012 *Renewable Electricity Futures Study* and EIA's *Annual Energy Outlook 2013*. These average growth rates were used for biomass, hydropower, and wind to forecast the existing (2011) capacity by state out to 2030. The annual growth rates from NREL and EIA applied to each renewable resource category, not just distributed generation as a whole. After comparing the 2015 forecasts using these annual growth rates to the planned projects for each resource under 10 MW contained in the SNL Database, Navigant deemed the annual growth rates to be appropriate for forecasting distributed generation growth for biomass, hydropower, and wind.

Given the very different technical aspects and market drivers for small solar distributed generation and large solar plants in the near-term, Navigant developed a separate forecasting method for distributed solar PV involving the NREL and EIA reports referenced above, as well as the International Energy Agency (IEA)'s *World Energy Outlook 2010*. Existing state-by-state solar data for 2011 came from IREC's *U.S. Solar Market Trends 2011*. Each state in the Eastern Interconnection was identified by experts from Navigant's Renewables Group as high, medium, or low in terms of solar DG growth. For the period from 2012 through 2016, constant annual growth rates were used (High: 6%, Medium: 4%, and Low: 2%). For the period from 2017 to 2030, Navigant kept the growth rate ratios fixed and adjusted the values for each year based on an average of long-term forecasts for the US market (IEA's *World Energy Outlook 2010*, NREL's *Renewable Electricity Futures* Study; and EIA's *Annual Energy Outlook 2013*). Refer to Appendix D for state-level growth rate assumptions for solar PV adoption.

3.5.2 Analysis Approach

The goal of this analysis is to forecast the adoption of demand-side resources, such as DG-R, and the associated impact on peak demand in terms of three factors: resource capacity; annual energy impact; and peak load impact. In the context of the DG-R forecast, these factors are defined as follows:

- **Resource capacity** refers to the total installed nameplate capacity of DG-R units;
- **Annual energy impact** refers to estimated annual electricity generation from DG-R units that are operational; and
- **Peak load impact** refers to the generation capacity credit[50] given to DG-R units.

Considerations and Identified Issues

Independent System Operators (ISOs) typically lack visibility into planned distributed generation installations, as their domain is the transmission system. Thus, as the operators of the distribution system, utilities are typically the only parties with such visibility.

While most utilities tend to publish detailed demand response program plans in their Integrated Resource Plans (IRPs), few utilities publish detailed plans for distributed energy resources, primarily

[50] For U.S. regional reliability organizations, the Electric Load Carrying Capability (ELCC) is the preferred method for determining the capacity credit. See the subsection on Base Case Forecast Methodology for more detailed discussion of ELCC.

because very few utilities own distributed energy assets. For example, residential and commercial utility customers have typically been the owners of distributed PV systems. As these customers make their renewable purchase decisions independently of the utility, the utility will not have direct visibility into future installed capacity. While every owner of a grid-connected PV system must sign an interconnection agreement with the utility, the PV owner will not sign that agreement until fairly close to the system activation date. Interconnection agreement data, with such a short lead-time, is insufficient for planning on a five-year time horizon. Additionally, utilities may not have to report this data.

Base Case Forecast Methodology

As described in Section 3.5.1, the resource capacity numbers were developed using different sources. For biomass and hydropower, the SNL Database was used to sum the total resource capacity by state for projects under 10 MW. For solar, IREC's *U.S. Solar Market Trends 2011* report was used as the basis for the resource capacity by state and SNL's Database was used to filter out any large solar projects over 10 MW. Lastly, for wind, AWEA's Project Database was used to sum the total resource capacity by state for projects under 10 MW.

To determine annual energy impact, each state's DG-R resource capacity was multiplied by the capacity factor and 8760 hours/year. The capacity factor used for biomass was 75%, for small hydropower was 50%, and for small wind was 30%[51]. These numbers were vetted by experts within Navigant's Renewables Group. The capacity factor for solar varied by state and came from the NREL/DOE System Advisor Model.

To estimate the potential for peak load impact, Navigant considered the impact of variable-output resources on system security. The Electric Load Carrying Capability (ELCC) Method is NERC's preferred method for determining the capacity credit for variable resources such as wind and solar.[52] Power system planners use a power system reliability model to calculate ELCC, which measures the additional demand that a specific generator can meet without any net change in electric system reliability. According to an NREL study, "ELCC can differentiate among generators of varying reliability, size, and on-peak versus off-peak delivery. Plants that are consistently able to deliver during periods of high demand have a high ELCC, and less reliable plants have a lower ELCC".[53]

Each ISO or other regional reliability organization sets its own capacity credit for each variable-output resource, as seen in Table 3-26. Many states are broken up into the jurisdiction of multiple ISOs/RTOs. Using maps from FERC, NREL, and the ISO/RTO Council, Navigant estimated the percentage breakdown by geographic region and proportionally applied ELCC numbers by resource category.

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[51] While wind resources do vary by region, a single capacity factor was used for all small wind projects to represent the capacity factor generally required for a small-scale wind project to be economically viable.
[52] North American Electric Reliability Corporation, *Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning*, (Princeton, NJ: North American Electric Reliability Corporation, 2011).
[53] Rogers, J. and K. Porter, *Summary of Time Period-Based and Other Approximation Methods for Determining the Capacity Value of Wind and Solar in the United States*, (Golden, CO: National Renewable Energy Laboratory, 2012).

Since biomass and hydropower are not considered to be variable renewable resources, it makes sense that their capacity credit is at or near 100%. The capacity credit for solar and wind varies significantly by planning group, which is not surprising given their variable natures.

Table 3-26. Effective Capacity Contribution for Each Renewable Resource[54]

Planning Group	Biomass Capacity Credit	Solar Capacity Credit	Hydropower Capacity Credit	Wind Capacity Credit
PJM	99.9%	37.5%	99.7%	15.2%
MISO	100%	37.5%	100%	6.5%
ISO-NE	100%	25.0%	75.2%	23.3%
NYISO	96.5%	66.7%	89.6%	10.0%
SPP	100%	100%	95.9%	7.7%
SERC VACAR	100%	100%	100%	15.2%
SERC Central	100%	100%	100%	53.5%
SERC Southeast	100%	100%	100%	7.7%
SERC Delta	100%	100%	100%	7.7%
Florida	100%	15.9%	100%	7.7%

Scenario Analysis Approach

For the scenario analysis of DG-R, the team adjusted the additional growth factors to account for the changes in scenario driver conditions. In particular, the team assumed that the following drivers were particularly influential to the adoption of DG-R:

- **Economic Growth:** Changes in economic growth typically impact the load growth, so the adoption of DG-R could increase to help meeting the growing demand. Utilities may also choose to adopt DG-R units to replace retired fossil fuel units.
- **Natural Gas Prices:** Retail electricity prices essentially mirror the natural gas market. Since natural gas prices have been declining since 2008, it is more difficult for DG-R units to be cost-effective.
- **Retail Electricity Prices:** An important motivation for residential and small commercial entities to install a DG-R unit is to reduce their utility costs. As such, changes in the retail electricity price would directly affect their decisions on whether or not to adopt DG-R.

Beyond these three drivers, changes in relevant policies (e.g., Renewables Portfolio Standards and greenhouse gas regulations) would likely have a small effect on the adoption of DG-R. These types of policies typically encourage large utility-scale renewable projects, and because DG-R is defined as resources less than 10 MW, the effects on the DG-R forecast are minimal. Additionally, it was assumed that technological advancement and customer acceptance would not have a significant impact on the forecast.

[54] North American Electric Reliability Corporation, *2011 Long-Term Reliability Assessment*, (Washington, DC: North American Electric Reliability Corporation, 2011).

3.5.3 Results

Base Case Results

Table 3-27 presents the forecast of DG-R resource capacity through 2030, aggregated by U.S. Census Region.

Table 3-27. Projected DG-R Resource Capacity by U.S. Census Region

U.S. Census Division	U.S. Census Region	Projected DG-R Resource Capacity (MW)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	1,014	1,096	1,195	1,316	2,285	3,651	5,355
	Middle Atlantic	2,215	2,845	3,585	4,473	11,054	19,877	30,611
Midwest	East North Central	1,068	1,117	1,162	1,211	1,463	1,762	2,103
	West North Central [a]	573	581	589	596	625	666	713
South	South Atlantic	967	1,167	1,398	1,675	3,666	6,282	9,406
	East South Central	119	147	177	211	418	664	940
	West South Central [a b]	169	197	227	261	463	700	962
TOTAL		6,126	7,150	8,333	9,744	19,974	33,603	50,091

a. *Portions of both Montana and New Mexico fall within Eastern Interconnection territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

Refer to Appendix A for state-by-state breakdown of the resource capacity forecast.

From these capacity values, Navigant estimated annual energy impact by applying the respective net capacity factor and for a given year, aggregating the individual results across the state. Peak load impact was estimated in a similar manner, except the appropriate resource capacity credit was directly applied to a state's total capacity in a given year. Table 3-28 and Table 3-29 present the forecasted annual energy impact and peak load impact of DG-R resources, respectively.

Table 3-28. Projected DG-R Annual Energy Impact by U.S. Census Region

U.S. Census Division	U.S. Census Region	Projected DG-R Annual Energy Impact (GWh/yr)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	3,939	4,065	4,204	4,374	5,646	7,439	9,676
	Middle Atlantic	6,122	6,874	7,721	8,738	16,069	25,967	38,106
Midwest	East North Central	5,256	5,418	5,545	5,691	6,276	7,026	7,971
	West North Central [a]	2,025	2,055	2,082	2,107	2,198	2,337	2,508
South	South Atlantic	3,810	4,145	4,499	4,922	7,726	11,422	15,885
	East South Central	485	532	578	630	924	1,277	1,684
	West South Central [a b]	619	668	716	770	1,069	1,426	1,833
TOTAL		22,257	23,756	25,345	27,233	39,909	56,894	77,664

a. *Portions of both Montana and New Mexico fall within Eastern Interconnection territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

Table 3-29. Projected DG-R Peak Load Impact by U.S. Census Region

U.S. Census Division	U.S. Census Region	Projected DG-R Peak Load Impact (MW)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	644	668	695	728	983	1,341	1,788
	Middle Atlantic	1,363	1,636	1,954	2,335	5,129	8,864	13,397
Midwest	East North Central	910	940	965	994	1,121	1,278	1,468
	West North Central [a]	230	236	240	245	266	290	319
South	South Atlantic	806	932	1,075	1,244	2,411	3,915	5,690
	East South Central	118	146	176	210	417	663	938
	West South Central [a b]	127	154	184	217	419	655	915
TOTAL		4,198	4,713	5,289	5,972	10,745	17,007	24,516

a. *Portions of both Montana and New Mexico fall within Eastern Interconnection territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

Based on this forecast, biomass and solar PV capacity will steadily increase; whereas changes in hydro and wind capacity will remain minimal through 2030. Figure 3-19, Figure 3-20, and Figure 3-21 present the forecasted resource capacity, annual energy impact, and peak load impact of DG-R resources, respectively.

Figure 3-19. DG-R Resource Capacity through 2030 by Resource Type

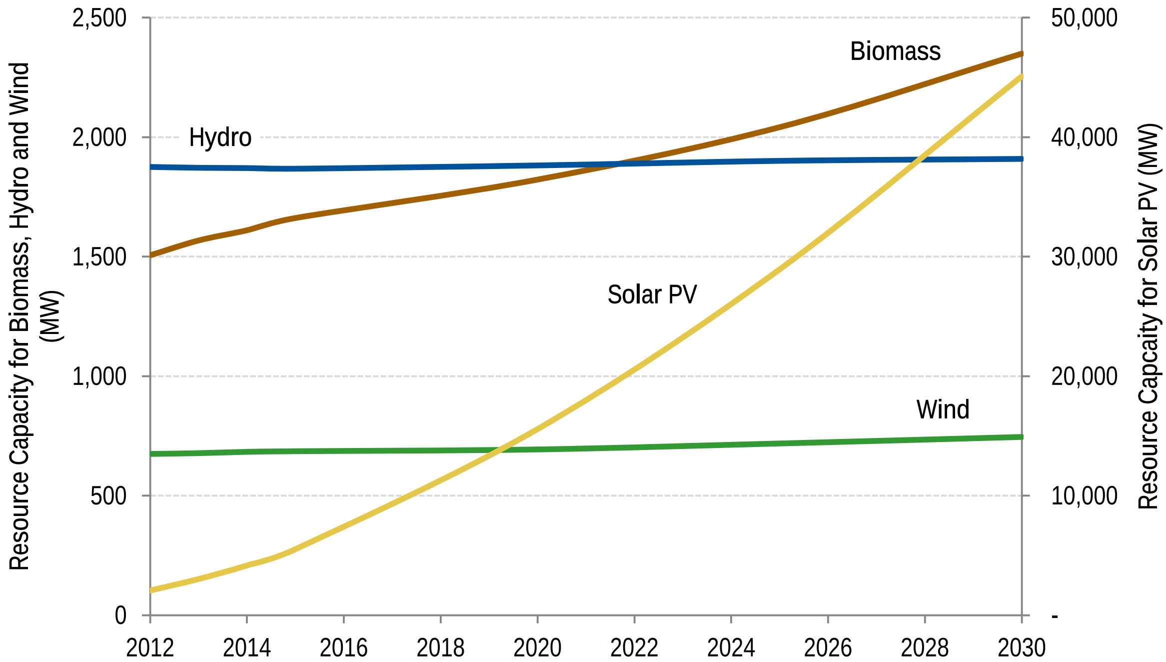


Figure 3-20. DG-R Annual Energy Impact through 2030 by Resource Type

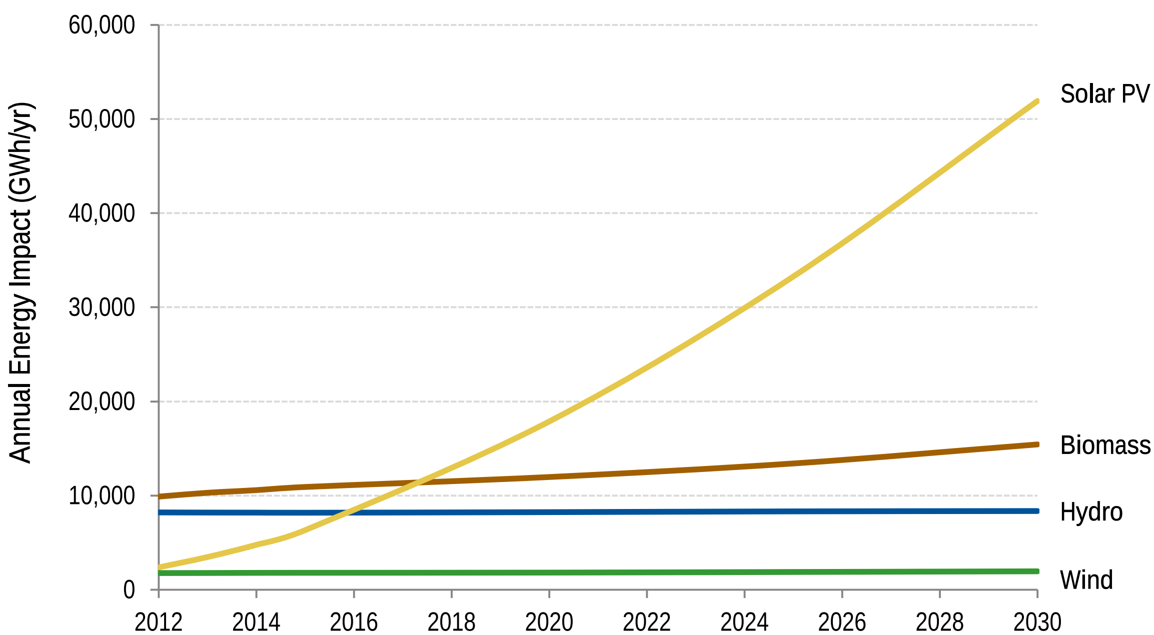
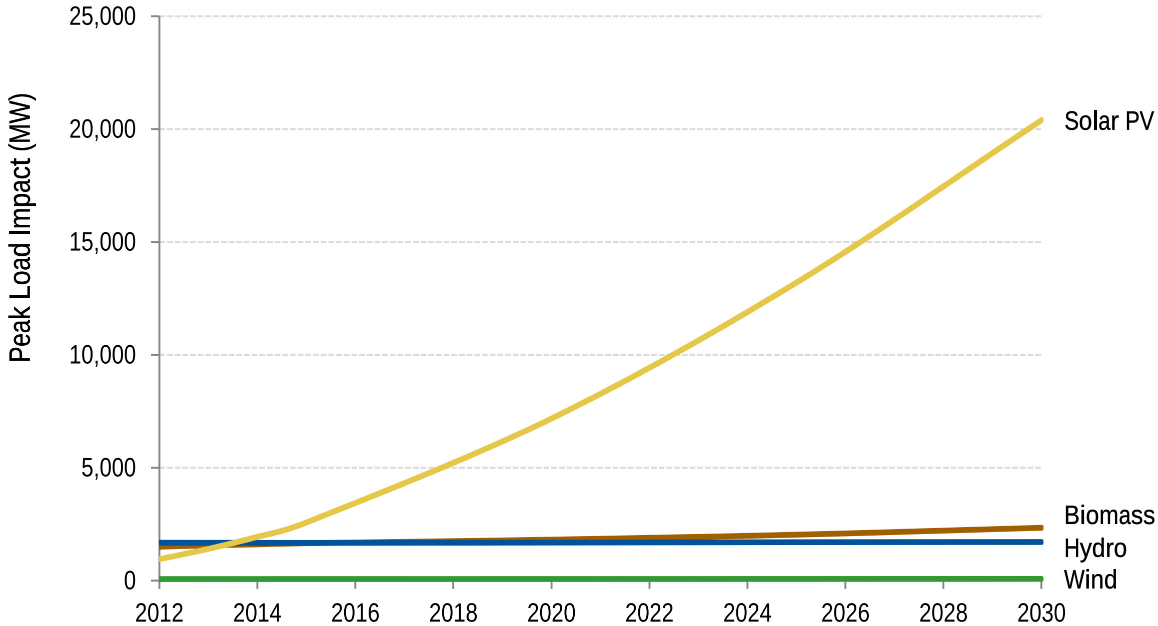


Figure 3-21. DG-R Peak Load Impact through 2030 by Resource Type



While hydropower and biomass made up 65% of cumulative installed capacity of distributed renewable resources in 2011, they comprised 86% of annual energy impact in 2011 due to their high capacity factors. While PV accounted for 24% of the total DG-R resource capacity, it made up only 7% of the annual energy impact due to its relatively low capacity factor. In terms of peak load impact, since hydropower and biomass have capacity credits at or near 100%, their peak load impact through 2030 is nearly identical to the resource capacity. The capacity credit for solar varies greatly by region (from 15.9% to 100%), but across the entire Eastern Interconnection, the peak load impact is about 50% of the resource capacity. Wind has a significantly lower capacity credit than biomass, hydropower, and PV; and as a result, its peak load impact is only about 10% of the resource capacity.

In terms of state-level distribution of resources, DG-R existing resource capacity in the Eastern Interconnection is fairly dispersed. No state comprises greater than 15% of the total resource capacity and the top five states, New York (15%), New Jersey (13%), Minnesota (6%), Michigan (6%), and Wisconsin (6%), comprise just 46% of the total.

The distributed solar PV capacity is the most concentrated of the renewable energy resources. One state, New Jersey, comprises 44% of the total and the top five states account for 74%. The remaining four states out of the top five are: Pennsylvania (11%), New York (7%), Florida (6%), and North Carolina (6%). New Jersey's extensive installed distributed PV capacity is largely due to the state's aggressive solar carve-out within its Renewable Portfolio Standard. The most recent revision to the policy has interim annual requirements with a specification that by 2028, 4.1% of the state's retail electricity sales must come from solar.

Distributed wind capacity is also highly concentrated. Minnesota represents 37% of all wind capacity less than 10 MW and the top five states together form 66%. The remaining four out of the top five states are: Iowa (12%), Massachusetts (9%), Texas (5%), and Illinois (4%). Minnesota has a long history of promoting distributed wind. In 2005, its legislature passed a community-based development (C-BED) statute, which promotes locally owned wind energy facilities within the state and provides a framework for community wind projects to negotiate with utilities.

Existing hydropower capacity is highly concentrated among five states. Together, the top five states contribute 63% to the total: New York (25%), Maine (12%), Wisconsin (9%), Michigan (9%) and Vermont (8%).

The existing distributed biomass capacity in the Eastern Interconnection is less concentrated. The top five states, New York (10%), Illinois (10%), Michigan (9%), Pennsylvania (7%), and Wisconsin (7%), only contribute 43% to the total. This is not surprising given that: the availability of biomass-based resources is more geographically dispersed than attractive wind, solar, and hydro resources; landfill gas plants can be located anywhere there is a landfill; and biomass-specific energy policy targets are less prevalent than those for other distributed resources like solar; solar carve-outs are common while biomass carve-outs are not.

Refer to Appendix A for state-by-state breakdown of the annual energy impact and peak load impact forecasts.

Scenario Results

Table 3-30 presents the forecast of DG-R peak load impact through 2030 for the Base Case and four scenarios outlined in Section 3.5.2.

Table 3-30. Scenario Analysis of DG-R Peak Load Impact through 2030

Scenario	Projected DG-R Peak Load Impact (MW)						
	2012	2013	2014	2015	2020	2025	2030
Base Case	4,198	4,713	5,289	5,972	10,745	17,007	24,516
Scenario 1	4,198	4,879	5,516	6,271	14,133	27,003	44,964
Scenario 2	4,198	4,763	5,357	6,061	11,695	19,671	29,748
Scenario 3	4,198	4,807	5,417	6,140	12,551	22,138	34,713
Scenario 4	4,198	4,641	5,192	5,846	9,714	14,432	19,827

Figure 3-22 presents the forecast of DG-R peak load impact through 2030 for the Base Case and four scenarios in graphic form. Scenario 1 (with strong economic growth and aggressive policy goals) has the largest peak load impact through 2030 as a result of the assumed high electricity prices and carbon pricing scheme. The next highest is Scenario 3 (with weak economic growth and aggressive policy goals) based on the assumed national Renewables Portfolio Standard and states' higher targets. Scenario 2 (with strong economic growth and relaxed policy goals) is slightly higher than the Base Case as a result of the assumed small increase in economic growth through 2030 and higher natural gas prices. Scenario 4 (weak economic growth and relaxed policy goals) is lower than the Base Case because of the assumed decrease in economic growth through 2030 and lower electricity and natural gas prices.

Figure 3-22. Scenario Analysis of DG-R Peak Load Impact through 2030

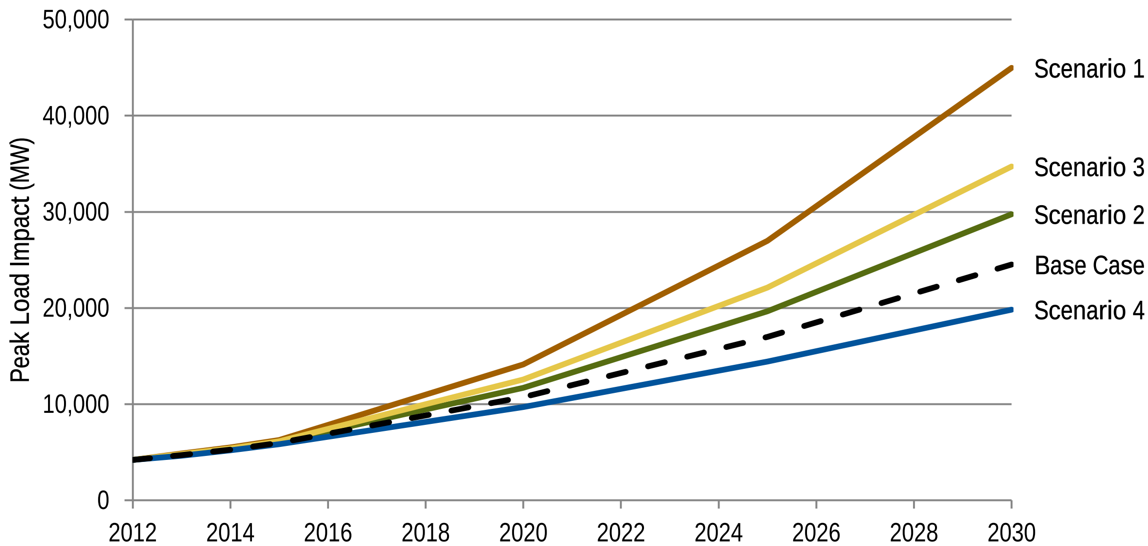


Figure 3-23 and Figure 3-24 show peak load impact through 2030 for Scenario 1, broken down by resource type. This scenario has 20,342 MW of additional peak load impact from solar than does the Base Case. This scenario also has 102 MW of additional peak load impact from biomass, as compared to the Base Case. Wind is only forecasted to provide an additional 3 MW and hydropower is nearly identical to the Base Case, which is due to the low growth rates in both this scenario and the Base Case from 2016 to 2030.

Figure 3-23. Comparison of Peak Load Impact between Scenario 1 and Base Case for Solar PV

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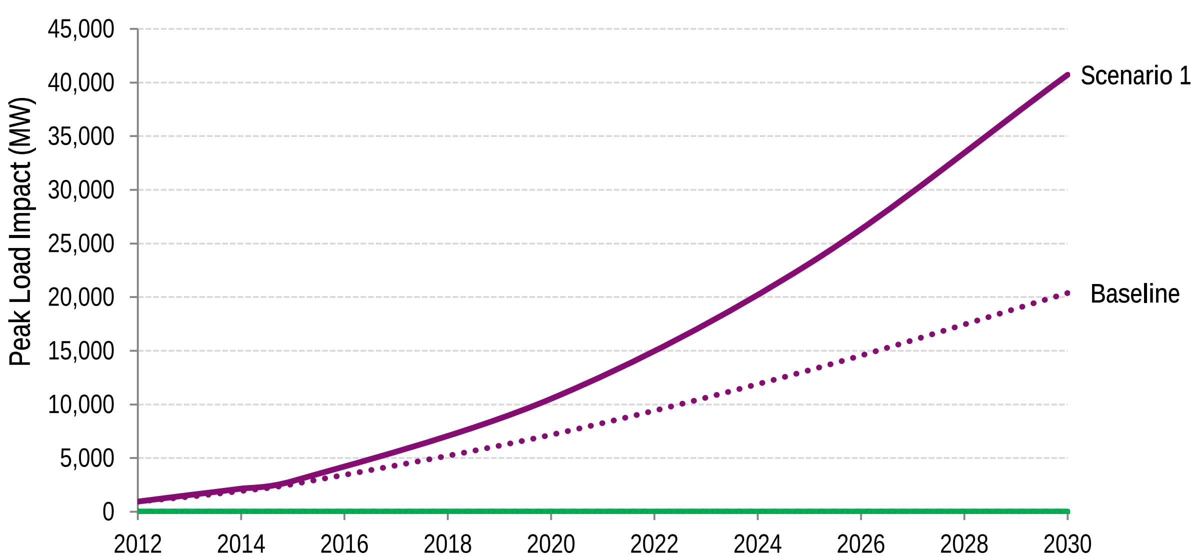
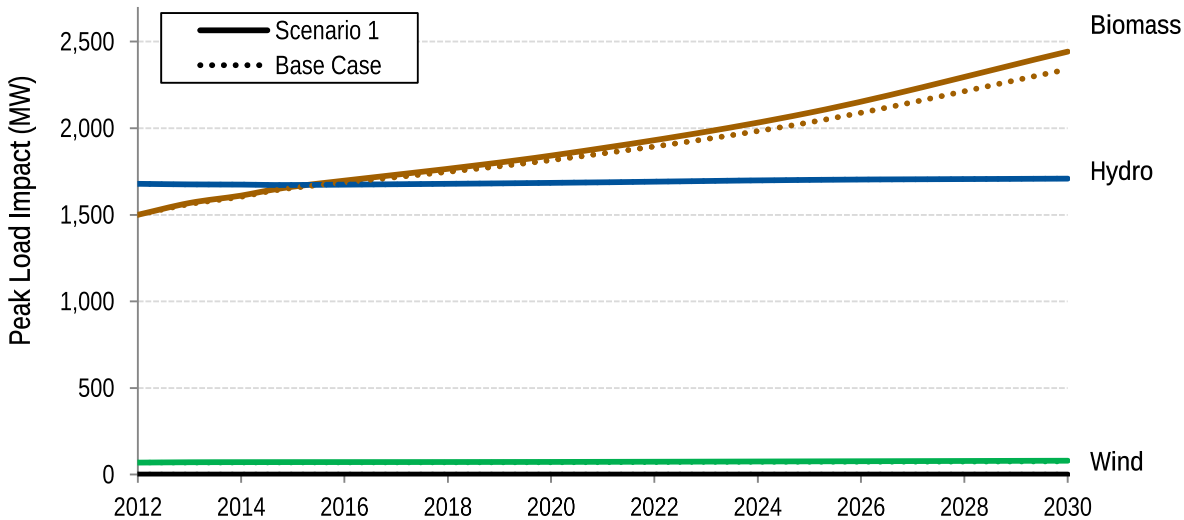


Figure 3-24. Comparison of Peak Load Impact between Scenario 1 and Base Case for Biomass, Hydro, and Wind



3.6 *Whitepaper #1: Smart Grid*

The smart grid is a complex network of hardware, software and operators that has the potential to fundamentally change the way in which electricity is delivered and consumed. The basic concept of the smart grid is to integrate technologies that enable enhanced monitoring, analysis, control, and communication capabilities into the existing electricity delivery infrastructure to improve its reliability, efficiency, and power quality. The term "smart grid" is not meant to describe a single system, but rather to serve as an "umbrella" term that encompasses many different manifestations of an advanced power grid.

This analysis represents a bottom-up estimate and forecast based on publicly and commercially available information. As the majority of data garnered relates to historical and current smart grid (SG) initiatives, Navigant developed a set of assumptions to forecast the deployment of SG technologies and functionalities and convert that forecast into a peak demand reduction and annual energy savings. Section 3.6.3 describes these assumptions and forecasting approach.

3.6.1 Description of Smart Grid as a Demand-Side Resource

While there are many smart grid technologies, functionalities, and benefits, the following two areas are most likely to have impacts on demand that may affect overall resource requirements and transmission load flows within the Eastern Interconnection (EI):

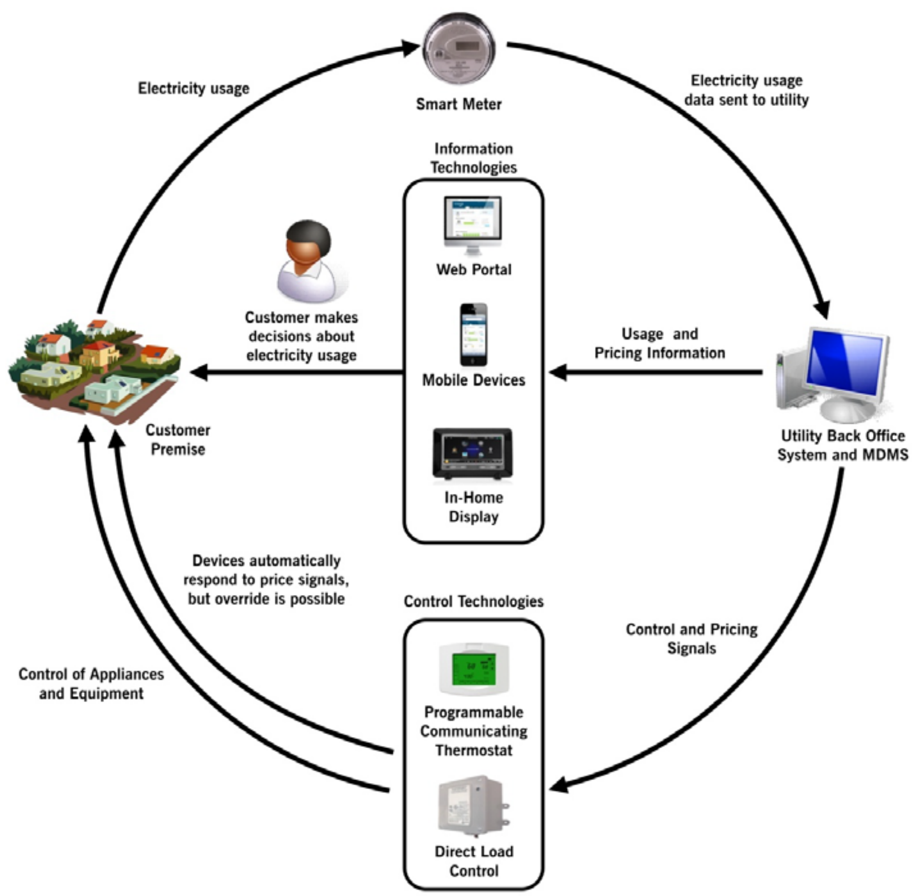
- Automated Metering Infrastructure (AMI) and Time-Based Rate (TBR) programs that are enabled by AMI and
- Conservation Voltage Reduction (CVR) programs.

AMI and Time-Based Rate Programs

Automated Metering Infrastructure (AMI) consists of three key elements: the smart meters, also known as AMI meters; the communications networks to transmit interval load data from the meter to the utility back offices; and the meter data management systems (MDMS) to store and process the interval load data for purposes such as enhanced billings and information feedback to customers[55].

Figure 3-25 provides a schematic of how the AMI communications network links smart meters, consumer devices, and the MDMS and the type of information that these devices and systems share.

Figure 3-25. Overview of Consumer Devices & Systems for Managing Electricity Consumption & Costs [56]



[55] In addition to these customer-facing functionalities, utilities may leverage smart meter data analyzed by MDMS for operational purposes such as outage management and meter tampering detection. However, this report focuses on features of AMI that aim to impact patterns of customer electricity usage and peak demands.
[56] U.S. DOE. "Demand Reductions from the Application of Advanced Metering Infrastructure, Pricing Programs, and Customer-Based Systems – Initial Results". Smart Grid Investment Grant Program. December 2012.

As Figure 3-25 shows, there are three categories of information that the integrated system of AMI meters and consumer devices collects, generates and responds to: electricity usage, appliance controls, and price signals from time-based rate programs. The ability to frequently communicate this information is an essential feature of the SG as a demand-side resource. AMI enables utility back office systems to collect and process interval load data and send it to billing systems. While utilities typically bill their customers on a monthly basis, SG and AMI can make information on electricity consumption available to customers (e.g., via web portals) the day after it has been collected. This requires communications networks that are capable of delivering accurate and reliable streams of data in a timely manner.

When time-based rate programs are involved, the communication of price signals becomes a crucial aspect of the programs' designs and can involve different forms of communications between utilities and customers. For example, certain time-based rates only go into effect when peak demand conditions reach a point where utilities want to activate a higher rate to lower peak demand. In such cases, customers enrolled in the rate program are informed of the changes to their electricity rates before the critical peak event that will trigger the higher rate. A typical program issues these notifications a day in advance (but sometimes only hours) via a number of communication channels including in-home displays, text messages, e-mails, web portal postings, and social network feeds.

Conservation Voltage Reduction Programs

Conservation voltage reduction (CVR) is an operational strategy designed to reduce the electricity consumed by customer appliances and equipment via reductions in distribution feeder voltages. For a residential customer meter in the United States, the voltage standard allows for a range of 114V to 126V[57,58] , as voltage levels outside of that range may damage customer equipment. By supplying electricity at voltages closer to the lower limit of the allowed end-of-line (EOL) voltage, many types of end-use equipment will reduce consumption. While CVR has been a well-known concept for at least 25 years, significant implementation has been limited by the inability to observe and control voltage levels along the length of distribution feeders. The increased visibility and control offered by voltage and volt-ampere reactive (VAR) optimization (VVO) technologies is prompting more utilities to consider CVR as a way to achieve peak demand reduction and overall energy conservation.

Reducing feeder voltage reduces energy consumption proportionately. The proportionality constant is called the "CVR factor" (CVRf). A CVRf of 1 indicates that a 1% reduction in voltage (ΔV) corresponds to a 1% reduction in energy consumption (ΔE).

$$CVRf = \frac{\Delta E(\%)}{\Delta V(\%)}$$

57 ANSI C84.1 (ANSI 1996)

58 Most distribution utilities employ a safety margin of about 2V when implementing CVR to ensure that EOL voltages never fall below the lower limit of 114V. This typically puts CVR EOL voltages at about 116V.

The CVR factor depends on the type of load connected to the feeder. Studies conducted by various U.S.-based utilities have shown that CVR factors between about 0.7 and 1.0 are common.[59]

There are a variety of ways for utilities to employ CVR. Most CVR implementations to date are considered "traditional static CVR", where the utility personnel manually "dial down" transformer to reduce voltage. In order to determine the operational parameters, these implementations rely on data gathering efforts to establish a statistical sample of EOL voltages. In cases where primary EOL voltage data is not available, utilities typically substitute it with voltage data at the distribution substations and use load flow calculations to estimate EOL voltages. Because of the uncertainty associated with these data, an additional voltage safety margin is sometimes employed, reducing the potential impacts of CVR.

However, the availability of digital communications and voltage monitoring equipment as a result of smart grid deployment allows utilities to enhance the performance of traditional CVR. This whitepaper focuses on three common types of enhanced CVR implementations that smart grid enables:

1. **Digitally Enhanced Static CVR:** Advanced digital meter infrastructure (AMI) is used to measure voltages at the customers' meters. This data can give utilities more confidence to reduce voltage safety margins. Continuous data availability combined with dispatchable load-tap transformers can allow operators to adjust transformer voltages remotely to, when possible, increase energy savings while ensuring that customers receive appropriate EOL voltages.
2. **Advanced Voltage Control[60]:** The AMI and dispatchable load-tap transformers used in "digitally enhanced static CVR" can be incorporated into an automated closed-loop system that continually optimizes tradeoffs in EOL voltage and energy consumption by precisely controlling voltage within acceptable limits. This more dynamic and actively controlled form of CVR can allow further reduction of voltage safety margins to maximize energy savings without risking excessively low EOL voltages.
3. **CVR as a Demand Response Resource:** If needed, utilities can also employ the technology used in "digitally enhanced static CVR" as a demand response resource to reduce peak demand. This would entail lowering voltages to the minimal acceptable level in order to avoid blackouts or to avoid building capacity that would only be used several hours during the year.

3.6.2 Sources and Data Collection

As implementation of dynamic pricing programs requires AMI meters and granular information on electricity consumption patterns, the first step of this analysis was to determine the penetration of existing and planned smart meter deployments. As a primary source for the number of AMI meters deployed in the Eastern Interconnection, the team relied on Form EIA-861 for both 2010 and 2011. To evaluate the current and planned levels of customer enrollment in time-based rate (TBR) programs, the team used the FERC-731 Demand Response/Time-Based Rate Programs and Advanced Metering Survey. Due to scarcity of publicly available information on CVR programs, the team relied mainly on its

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[59] For example: Berl, A. B.. "Conservation Voltage Reduction : Conservation Voltage Reduction: An Easy Way to Improve Energy Efficiency and Lower Demand Efficiency and Lower Demand". Presentation at NRECA 2011 CRN Summit. July 2011.
[60] "The Smart Grid: An Estimation of the Energy and CO2 Benefits." Pacific Northwest National Laboratory. January 2010. Page 3.27.

internal expertise as the primary data source. This lack of information on CVR is likely due to the small number of utilities that have implemented smart grid-enhanced CVR programs.

To supplement these data for AMI, TBR, and CVR, Navigant conducted its own utility survey and literature search of publicly available information on the websites of numerous utilities within each state, the Department of Energy (DOE) Smart Grid Investment Grant (SGIG), and Smart Grid Demonstration (SGD) programs. Furthermore, Navigant conducted interviews with various state energy agencies. The result is a comprehensive view of AMI deployment in the 39 Eastern Interconnection states and the District of Columbia.

3.6.3 Analysis Approach

The goal of this analysis is to forecast the adoption of demand-side resources and the associated impact on electricity demand in terms of three factors: resource capacity; annual energy impact; and peak load impact. In the context of the SG forecast, these factors are defined as follows:

- **Resource capacity** refers to the potential reduction in generation capacity requirements to meet annual peak demand within the Eastern Interconnection as a result of time-based rate (TBR) programs and conservation voltage reduction (CVR) programs;
- **Annual energy impact** refers to estimated reduction in annual electricity consumption as a result of CVR programs; and
- **Peak load impact** refers to the estimated reduction in generation capacity requirement to meet annual peak demand within the Eastern Interconnection as a result of TBR programs and CVR programs.

Considerations and Identified Issues - Automated Metering Infrastructure & Time-Based Rate Programs

One of the most significant challenges with respect to estimating the penetration of "smart meters" is defining what type of meter can be characterized as "smart". For this report, our team adopted the Federal Energy Regulatory Commission's (FERC) definition of "advanced meter" as the definition for AMI meters:

> Advanced meters measure and record usage data at a minimum, in hourly intervals, and provide usage data to both consumers and energy companies at least once daily. Data are used for billing and other purposes. Advanced meters include basic hourly interval meters and extend to real-time meters with built-in two-way communication capable of recording and transmitting instantaneous data[61].

Not included in this definition are digital meters used as a part of Automated Meter Reading (AMR) systems. An AMR system is "a system where aggregated kWh usage, and in some cases demand, is retrieved via an automatic means such as a drive-by vehicle or walk-by handheld system"[62]. In addition

[61]Federal Energy Regulatory Commission. 2012. *Assessment of Demand Response & Advanced Metering – Staff Report*. http://www.ferc.gov/industries/electric/indus-act/demand-response/2012/survey.asp. Accessed December 21, 2012.
[62] Roche, Jim. "AMR vs AMI". Electric Light and Power. Accessed December 12, 2012. http://www.elp.com/articles/powergrid_international/print/volume-13/issue-10/features/amr-vs-ami.html.

to the functionalities provided by AMR systems, AMI meters by this study's definition require a more extensive communications network that enables two-way communication between the utility and customer.

As AMI meters represent the most advanced form of electricity metering, they are typically what are envisioned with the term "smart grid"; and therefore, they are the type of meter documented in this report. However, in researching AMI deployments, it was apparent that some utilities have only one-way AMR meters even though they reported AMI meters or list them on their websites. To ensure that the data only comprise AMI meters, the team searched various utilities' websites to find as much information as possible about the type of meter.

Another challenge related to AMI is determining future levels of deployment. As AMI meters are a relatively new technology that requires significant financial and operational commitments for implementation[63], there is hesitance towards them. While AMI penetration has accelerated in the last several years as a result of the SGIG program, it is likely that the pace of installations will decelerate as the program concludes and other utilities wait to see the results of the deployment. Furthermore, there are concerns that regulatory bodies are raising across the U.S. During regulatory proceedings when utilities present the business cases for investments in AMI, the three core questions raised are: 1) cost recovery of the investments, 2) benefits from utility operational savings, and 3) benefits (to both utilities and customers) from the introduction of time-based rates and incentive-based programs.

In addition to issues regarding AMI meters, there are also some involving TBR programs. Traditionally, utilities have used rate designs that do not convey the time variability of electricity costs. Such rates include: flat rates in which all usage during a given period of time (e.g., 30-day billing cycle) is charged the same rate; and tiered rates which typically charge different rates based on blocks of usage (e.g., first 500 kWh vs. next 500 kWh) during a given period of time (e.g., 30-day billing cycle).

For this whitepaper, Navigant focused on several different types of TBR including[64]:

- **Time-of-Use (TOU) Rates** : TOU pricing typically applies to usage over broad blocks of hours (e.g., on-peak = 6 hours for weekday afternoons; off-peak = all other hours) where the price for each period is predetermined and constant. TOU rates are primarily implemented to provide incentives for changing the timing of the consumption of electricity (i.e., shifting from peak hours to off-peak hours) by reducing the cost of electricity in off-peak periods and increasing it in on-peak periods.
- **Real-Time Pricing (RTP):** RTP rates typically apply to usage on an hourly basis (but could apply to usage on as little as a 5-minute basis), where the price of electricity changes each hour of each day. RTP rates are primarily implemented to provide financial incentives for customers to shift consumption from on-peak to off-peak periods.

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[63] As installing and operating an AMI network requires substantial infrastructure and communications system investment, utilities are likely to deploy the technology across their entire systems, as opposed to limiting the deployment to certain sections of their systems.

[64] These definitions of time-based rates are based on U.S. DOE. "Demand Reductions from the Application of Advanced Metering Infrastructure, Pricing Programs, and Customer-Based Systems – Initial Results". Smart Grid Investment Grant Program. December 2012.

- **Variable Peak Pricing (VPP)**: VPP is a hybrid of TOU and RTP. Much like TOU, VPP comes with predefined periods for pricing, but similar to RTP, there are multiple price levels for the on-peak period varies depending on the costs of delivering electricity. VPP rates have a dual purpose: to change the timing of a customer's consumption of electricity and to reduce a customer's consumption of electricity over a certain number of hours on a limited number of days when certain system conditions occur (e.g., extremely high costs or system emergencies) by increasing the cost of electricity during on-peak periods on these limited days.
- **Critical Peak Pricing (CPP):** When utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical peak events during a specified time period (e.g., 3 pm – 6 pm on a hot summer weekday). With CPP, the price for electricity during these time periods increases. The time and duration of the price increase may or may not be predetermined based on the rate design. In some cases, the time and duration of the price increase may vary based on the demand of the electric grid. CPP rates are primarily implemented to reduce a customer's consumption of electricity over a certain number of hours on a limited number of days when certain system conditions occur.
- **Critical Peak Rebates (CPR)**: Similar to CPP, CPR is also designed around critical peak events called during pre-specified time periods. However, unlike CPP, the price for electricity during these time periods remains the same for customers with CPR. Instead, CPR provides the customer with a rebate of single, predetermined value for any reduction in consumption relative to what the utility defined as the expected level of electricity consumption for the customer. CPR is primarily implemented to reduce a customer's consumption of electricity over a certain number of hours on a limited number of days when certain system conditions occur.

One of the most significant considerations with these rate programs is a large variance in scale. For example, many utilities are conducting small-scale pilots that involve relatively few participants. Two of the primary goals of such initiatives are to evaluate the efficacy of the devices and customer experiences and to resolve systems integration issues. Consequently, these projects are typically not subjected to near-term decisions about investments that other demand-side management programs might, but are instead gathering information for potential future investments. There exist several projects that involve larger numbers of participants and focus more on near-term investment decisions regarding the potential roll-out of TBR programs.

Navigant assumes negligible annual energy impact from TBR programs based on the expectation that most customers will reduce peak demand by shifting their load to off-peak hours. This assumption is consistent with the data collected from IRPs and other sources, where most entities do not forecast energy savings from TBR programs.

Another major consideration in the evaluation of SG impact is its potential overlap with traditional demand response programs that do not require AMI meters. These incentive-based initiatives, which include direct load control (DLC) programs and both interruptible and curtailable rate programs, have a primary goal of reducing peak demand. DLC programs typically involve the installation of radio-controlled switches on devices such as central air conditioners, water heaters, and pool pumps. Customers agree to have the power to these devices turned off during predetermined peak periods, the number of which is usually capped for a given calendar year. The two rate programs also involve financial incentives to participants (mainly larger commercial and industrial customers) urging them to reduce demand to predetermined levels during scheduled events (e.g. emergencies). The advent of AMI and smart meters has enhanced the capabilities of these "legacy" programs by providing a common communications platform, a way to check remotely on the health of the DLC, and a mechanism for evaluating the changes in electricity consumption during DLC operation or rate program initiation. However, as DLCs, interruptible, and curtailable rate programs were offered and implemented successfully before the expanded use of AMI, Navigant has grouped into the Demand Response resource category. Refer to Section 3.2 for detailed discussion of these incentive-based programs.

Finally, it should be noted that Navigant focused its AMI and TBR program evaluation on residential and small to medium-sized commercial/industrial customers. The team chose this subset because having a variety of electricity pricing schemes is a novel institution to these customer types. Therefore, they will likely constitute a significant portion of the impact resulting from AMI deployment.

Considerations and Identified Issues - Conservation Voltage Reduction Programs

Few utilities have implemented CVR programs; therefore, because of the limited data set, Navigant evaluated specific case studies and extrapolated them to forecast the impact through 2030. The following examples are some of the cases analyzed for peak load impact and annual energy impact.

By using CVR to reduce electricity demand during peak periods, a utility can lower the load on generation, transmission, and distribution equipment, thereby helping defer the need for new capacity or upgrades to the distribution system. Georgia Power's Distribution Energy Efficiency Project has estimated a potential demand reduction of 200 MW if implemented on over 560 of its distribution feeders.[65]

Another example is a utility implementing capacitor controls and an integrated VVO model aimed at reducing both line losses and peak demand. Pilot testing on four circuits has produced peak demand reductions between 0.8 and 2.4%[66] and advanced deployment on 400 circuits is anticipated to reduce peak demand by about 75 MW. Reductions of this scale are significant, as a 200 MW reduction is similar in size to a large peaking power plant.

CVR can also help reduce capacity payments for those distribution companies that are billed on the basis of their maximum monthly peak demand. This could be especially valuable to smaller electric cooperatives and public power utilities that purchase wholesale power with a capacity charge. These utilities could reduce their annual capacity-rated costs even if CVR were applied for only a few hours per year.

Moreover, CVR techniques lower the voltage on distribution feeders. This reduces the amount of fuel required to generate electricity, and saves electricity customers money. While it is not necessary to employ smart grid technologies to implement CVR, optimizing voltage through the coordinated control of load tap changers, voltage regulators, and capacitor banks can increase its effectiveness.

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[65] "Can a Grid be Smart without Communications? A look at an Integrated Volt VAr Control (IVVC) Implementation," Barry Stephens, Georgia Power, Bob McFetridge, Beckwith Electric, April 25, 2012.
[66] "Ventyx Launches Network Manager™ DMS v5.3 With Model-Based Volt/VAR Optimization," Ventyx, December 5, 2011.

Some power companies have demonstrated energy savings using CVR. In a 2010 study, Alabama Power and Duke Energy showed reductions in energy consumption of between 1.6% and 2.7% on test circuits under certain conditions. [67] In another study, AEP achieved a 3% energy savings with a 3% by lowering circuit voltage by 3%.[68] In addition, PECO has shown that by reducing circuit voltage by about 1.0% it can achieve energy consumption reductions of about 1.0%.[69] Based on this result, PECO has adopted CVR as one of its energy efficiency and conservation programs.

Base Case Forecast Methodology - Automated Metering Infrastructure & Time-Based Rate Programs

To forecast the Base Case number of AMI meters in the Eastern Interconnection, the team used the 2011 deployment numbers from the EIA Form-861 dataset as a starting point and supplemented it with additional information from literature sources and utility websites. Based on the number of AMI meters in 2011, the team used state legislation information, data provided on utilities' websites, responses from the survey, and knowledge garnered from conversations with state energy agencies to forecast future deployment.

Then, to determine the peak load impact resulting from TBR programs, the team used the 2012 FERC-731 dataset and focused on utilities with known AMI meter installations that reported residential or small to medium commercial/industrial customers with one of the following pricing programs: Critical Peak Pricing, Peak Time Rebate, Real-Time Pricing, and Time-of-Use. The team found that for this group of utilities, the realized reduction was about 45% of the potential reduction. To project the realized peak load impact out from 2011 to 2015, the team determined a relationship between the number of customers within a given type in a specific state that have AMI meters and the potential peak reduction due to TBR programs. Then, as the number of those customers with AMI meters increased, the amount of potential peak reduction was augmented accordingly.

As TBR programs for residential and small to medium commercial/industrial customers are still rapidly evolving, the team chose to model the amount of peak load impact in 2020, 2025, and 2030 independently of the 2012 FERC-731 data. Various studies document the difference in impact between pricing programs associated with technology, such as programmable communicating thermostats (PCTs) and in-home displays (IHDs), and those without. For example, the Brattle Group analyzed a series of residential programs and found that TOU programs without technology have an average peak load impact of 4%, whereas those with technology have 26%.[70] They found that CPP programs exhibited a similar trend, as those without technology had an average of 17% peak load impact and those with had 36%.

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[67] "Voltage Optimization More than Pays for Itself," Transmission & Distribution World, August 1, 2010.

[68] "Volt-VAR Optimization on American Electric Power Feeders in Northeast Columbus," K.P. Schneider and T.F. Weaver.

[69] Quarterly Report to the Pennsylvania Public Utility Commission For the Period
June through August 2011 Program Year Three, PECO Energy Company, October 15, 2011.

[70] Faruqui, Ahmad and Sanem Sergici. "Household Response to Dynamic Pricing of Electricity-A Survey of the Empirical Evidence." February 2010. Pg 45.

In addition to the external sources, Navigant also used internal expertise to estimate the percentage of peak load impact associated with various combinations of TBR programs. The team developed two sets of reduction percentages: one for "leading" states with existing TBR programs, and one for states without. Leading states include: Connecticut, Massachusetts, Maryland, Maine, Minnesota, New Jersey, New York, Oklahoma, Rhode Island, Vermont, and Wisconsin. The team applied these reduction percentages to the average load data by customer type and state from the FERC 2009 *Assessment of Demand Response Potential*. Table 3-31 and Table 3-32 summarize these assumptions that form the basis of the forecast in 2020, 2025, and 2030 for residential and non-residential customers, respectively.

Table 3-31. TBR Enrollment and Peak Load Impact Assumptions for Residential Customers

State Type	Program Type[1]		% of Customers Enrolled			Peak Load Impact per Customer
			2020	2025	2030	
Leading states[2]	TOU	With technology	1%	2%	3%	25%
		Without technology	9%	8%	7%	5%
	RTP	With technology	0%	0%	0%	30%
		Without technology	1%	1%	1%	10%
	VPP	With technology	0%	0%	0%	40%
		Without technology	1%	1%	1%	20%
	CPP	With technology	1%	1%	2%	35%
		Without technology	5%	4%	4%	15%
	CPR	With technology	0%	1%	1%	10%
		Without technology	3%	2%	2%	10%
Other States	TOU	With technology	1%	1%	2%	25%
		Without technology	5%	4%	4%	5%
	RTP	With technology	0%	0%	0%	30%
		Without technology	1%	0%	0%	10%
	VPP	With technology	0%	0%	0%	40%
		Without technology	1%	0%	0%	20%
	CPP	With technology	0%	1%	1%	35%
		Without technology	2%	2%	2%	15%
	CPR	With technology	0%	0%	1%	10%
		Without technology	1%	1%	1%	10%

1. *"Technology" refers to consumer devices that facilitate customer engagement in TBR programs (e.g., programmable communicating thermostats and in-home displays).*
2. *Leading states include: Connecticut, Massachusetts, Maryland, Maine, Minnesota, New Jersey, New York, Oklahoma, Rhode Island, Vermont, and Wisconsin.*

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Table 3-32. TBR Enrollment and Peak Load Impact Assumptions for C&I Customers

State Type	Program Type[1]		% of Customers Enrolled 2020	2025	2030	Peak Load Impact per Customer
Leading states[2]	TOU	With technology	3%	5%	8%	25%
		Without technology	12%	10%	8%	5%
	RTP	With technology	0%	1%	1%	30%
		Without technology	1%	1%	1%	10%
	VPP	With technology	0%	1%	1%	40%
		Without technology	1%	1%	1%	20%
	CPP	With technology	2%	3%	4%	35%
		Without technology	6%	5%	4%	15%
	CPR	With technology	1%	2%	2%	10%
		Without technology	4%	3%	2%	10%
Other States	TOU	With technology	2%	3%	4%	25%
		Without technology	6%	5%	4%	5%
	RTP	With technology	0%	0%	0%	30%
		Without technology	1%	1%	0%	10%
	VPP	With technology	0%	0%	0%	40%
		Without technology	1%	1%	0%	20%
	CPP	With technology	1%	1%	2%	35%
		Without technology	3%	2%	2%	15%
	CPR	With technology	1%	1%	1%	10%
		Without technology	2%	2%	1%	10%

1. *"Technology" refers to consumer devices that facilitate customer engagement in TBR programs (e.g., programmable communicating thermostats and in-home displays).*
2. *Leading states include: Connecticut, Massachusetts, Maryland, Maine, Minnesota, New Jersey, New York, Oklahoma, Rhode Island, Vermont, and Wisconsin.*

Base Case Forecast Methodology - Conservation Voltage Reduction Programs

This assessment incorporates information on expected demand reduction and energy savings for CVR programs that was available in IRPs or other sources. However, as the data did not adequately cover the entire Eastern Interconnection, the team also developed several assumptions that apply to three different groups of states: states with no publicly documented CVR initiatives; states with existing CVR projects; and states that are leading with energy efficiency initiatives, which indicates favorable policy climate for utilities to implement CVR programs.

Table 3-33. Assumed Groups of States with Similar DR Deployment Trends

States with no existing CVR initiatives		States with CVR Projects		States Leading in EE Initiatives
Arkansas	Missouri	Alabama	North Carolina	Connecticut
District of Columbia	Montana*	Georgia	Ohio	Massachusetts
Delaware	Nebraska	Indiana	Pennsylvania	Maine
Florida	New Hampshire	Kentucky	South Dakota	Minnesota
Illinois	New Mexico*	Maryland	Tennessee	New Jersey
Iowa	North Dakota	Michigan	Virginia	Rhode Island
Kansas	Oklahoma	New York	West Virginia	Vermont
Louisiana	South Carolina			Wisconsin
Mississippi	Texas*			

Notes: For Montana, New Mexico and Texas, only the Eastern Interconnection portion of the state were considered.

This study assumes that substations with voltage control capability serve 70% of the distribution system peak demand within Eastern Interconnection. Although higher levels of voltage reduction are possible, this study also assumes peak demand reduction will be between 2% to 3% depending on whether the state has ongoing CVR initiatives as of 2011. Also, Navigant assumed that the demand reduction is equal to the resource capacity. Similarly, this study assumes that the Annual Energy Impact from CVR programs would be limited to a range of 1% to 2%. Furthermore, Navigant assumes that 90% of the equipment will respond properly at any given time. Table 3-34 summarizes the CVR assumptions.

Table 3-34. CVR Demand Reduction Assumptions

Factors Considered		2012	2013	2014	2015	2020	2025	2030
% of distribution system peak demand served by substations with voltage control capability		70%	70%	70%	70%	70%	70%	70%
% of distribution system peak demand served by substations with voltage control capability and implementing CVR	*States with no existing CVR initiatives*	0.0%	0.0%	0.0%	0.0%	2.5%	5.0%	7.5%
	States with CVR projects			2.0%	5.0%	10.0%	15%	20.0%
	States leading with EE initiatives			0.0%	5.0%	10.0%	15%	20.0%
% of equipment that responds properly	*States with no existing CVR initiatives*	90%	90%	90%	90%	90%	90%	90%
	States with CVR projects					100%	100%	100%
	States leading with EE initiatives					90%	90%	100%
Peak demand reduction	*States with no existing CVR initiatives*	2%	2%	2%	2%	2%	2%	2%
	States with CVR projects					3%	3%	3%
	States leading with EE initiatives					2%	2%	2%
Annual energy savings	*States with no existing CVR initiatives*	1%	1%	1%	1%	1%	1%	1%
	States with CVR projects					2%	2%	2%
	States leading with EE initiatives					1%	1.5%	2%

Scenario Analysis Approach

For the scenario analysis of SG, the team assumed that the following drivers were particularly influential to the adoption of SG:

- **Energy Policies that Support Demand-Side Resources:** One of the primary drivers for SG is expected to be state, regional, and federal policy supporting SG, particularly regulations that guide cost allocation for automated metering infrastructure and energy efficiency standards met by conservation voltage reduction.
- **Economic Growth:** Changes in economic growth typically impact load growth. One of the key reasons utilities adopt TBR is to meet increased load growth in a more cost-effective way than building new capacity. Thus, strong economic growth is expected to result in higher SG penetration.
- **Customer Acceptance:** The success of TBR programs relies on customers' willingness to participate. Greater customer acceptance leads to more available SG resource capacity and higher peak demand impacts, especially if retail electricity prices increases.
- **Technology Advancement:** Advancements in control systems and communications, including lower installation and integration costs as these technologies become more mature, are expected to play a significant role in future SG growth. Technologies such as advanced meters, smart thermostats, Automated Demand Response (Auto-DR), and others will allow customers and utilities to control a wider range of end-use loads with greater confidence, reliability, and fidelity.

3.6.4 Results

Base Case Results

Figure 3-26, Figure 3-27, and Figure 3-28 show the forecasted total resource capacity, annual energy impact and peak load impact for SG. Based on the forecast, the overall level of impact associated will slightly increase through 2015, after which the impact starts to increase more rapidly. This change in the trend over the forecast timeframe is driven primarily by more aggressive adoption of smart grid technologies by utilities and their customers.

Figure 3-26. Total SG Resource Capacity through 2030

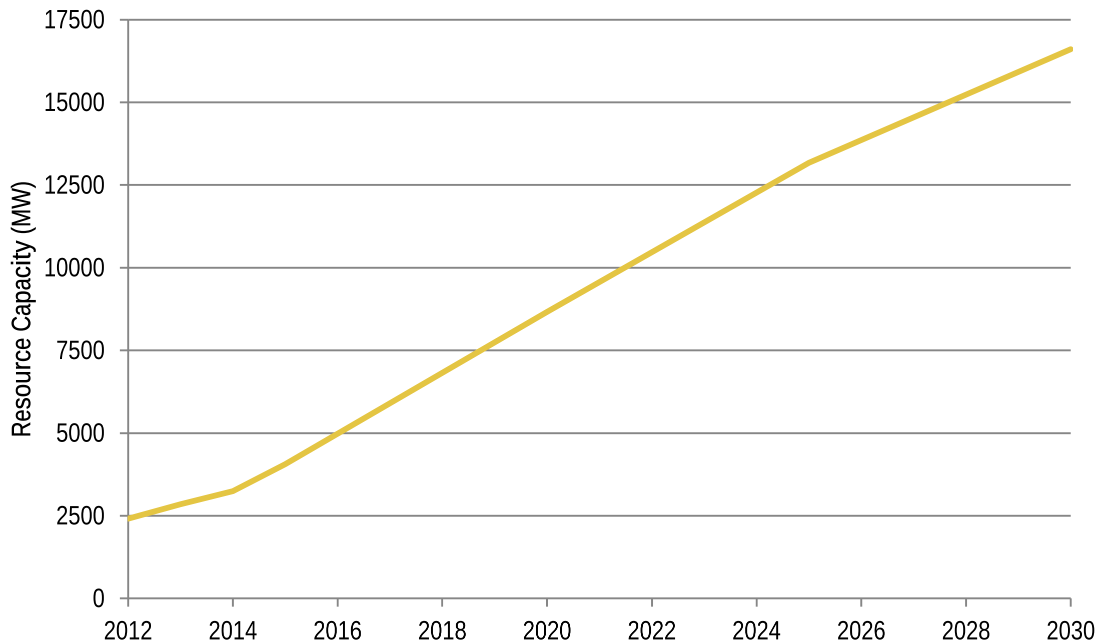


Figure 3-27. Total SG Annual Energy Impact through 2030

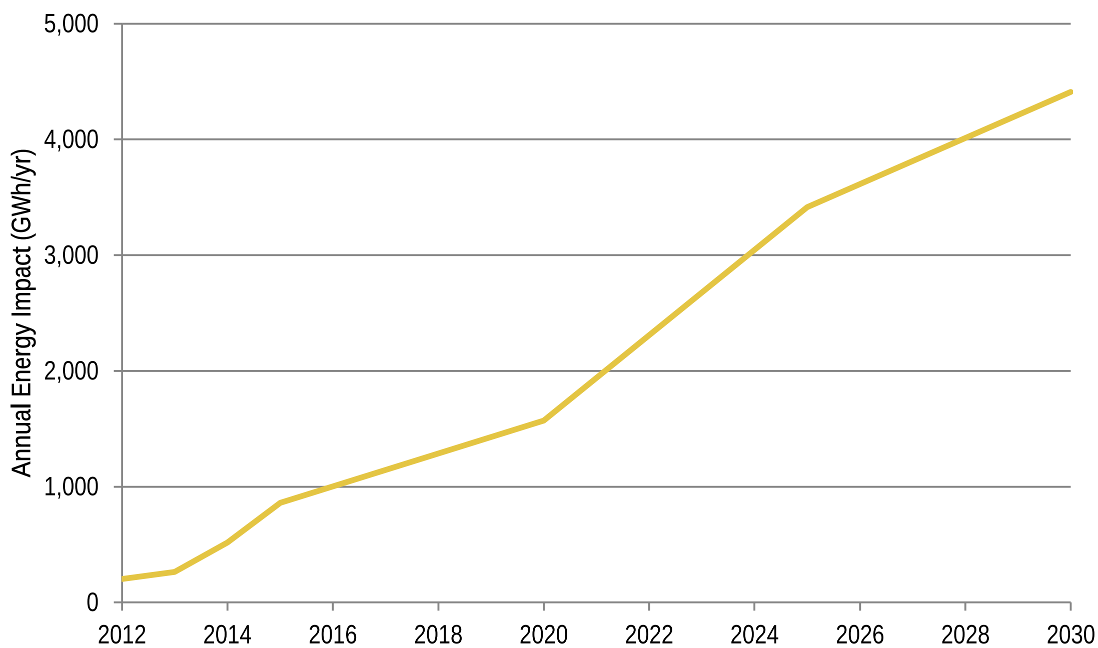
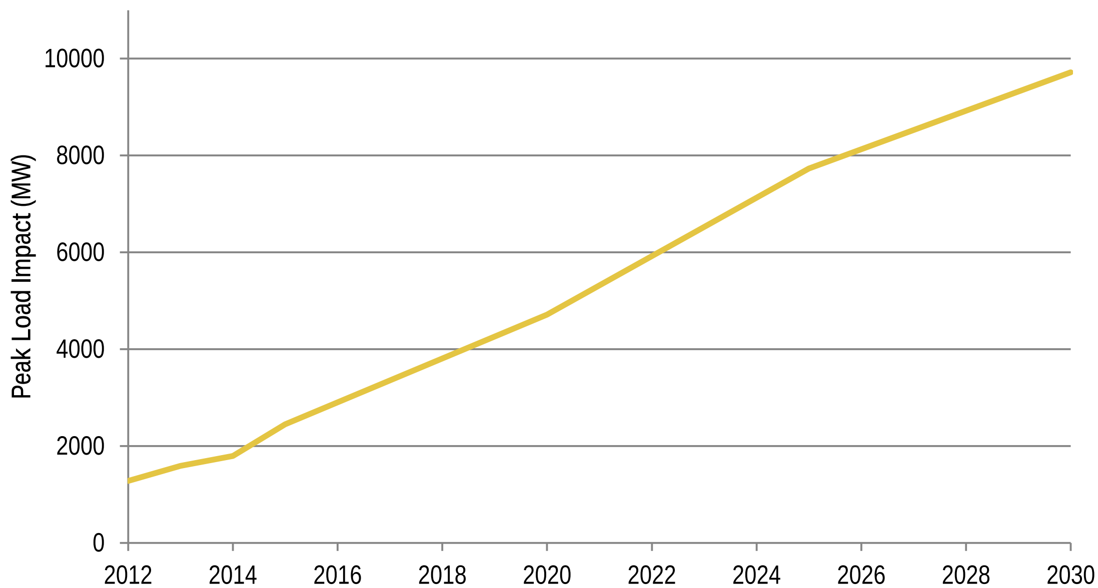


Figure 3-28. Total SG Peak Load Impact through 2030



Automated Metering Infrastructure (AMI)

Figure 3-29 and Figure 3-30 depict the forecasted AMI deployment in the residential and commercial sectors, respectively.

Figure 3-29. Residential AMI Deployment by U.S. Census Region

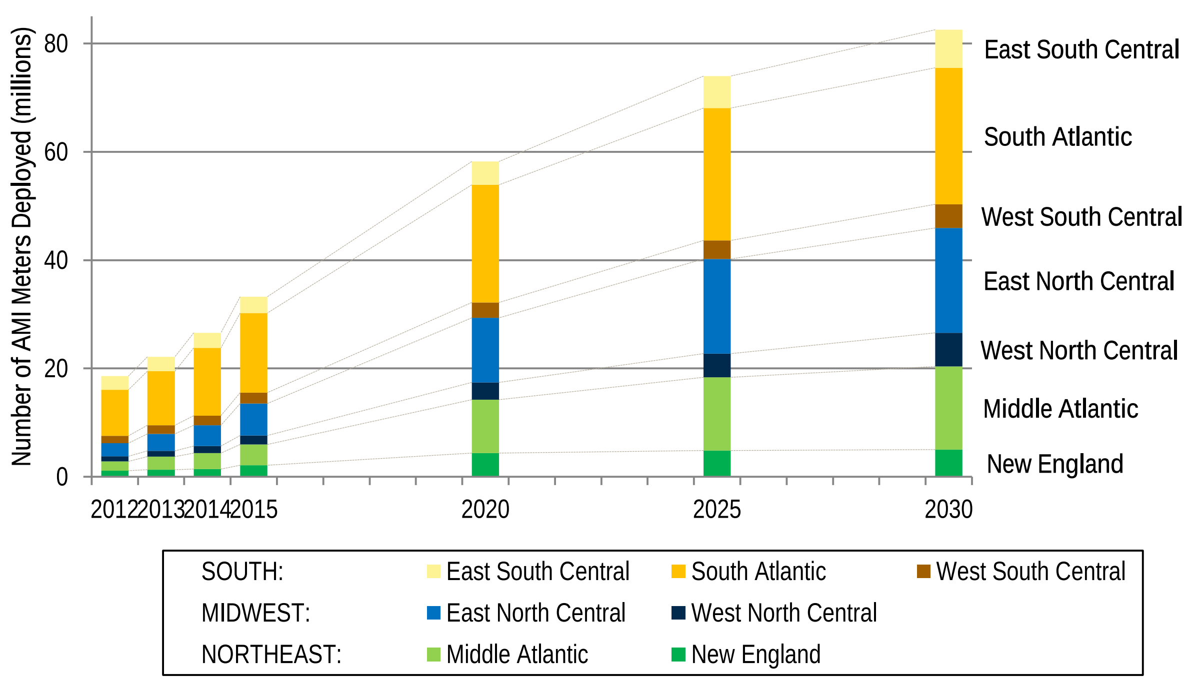
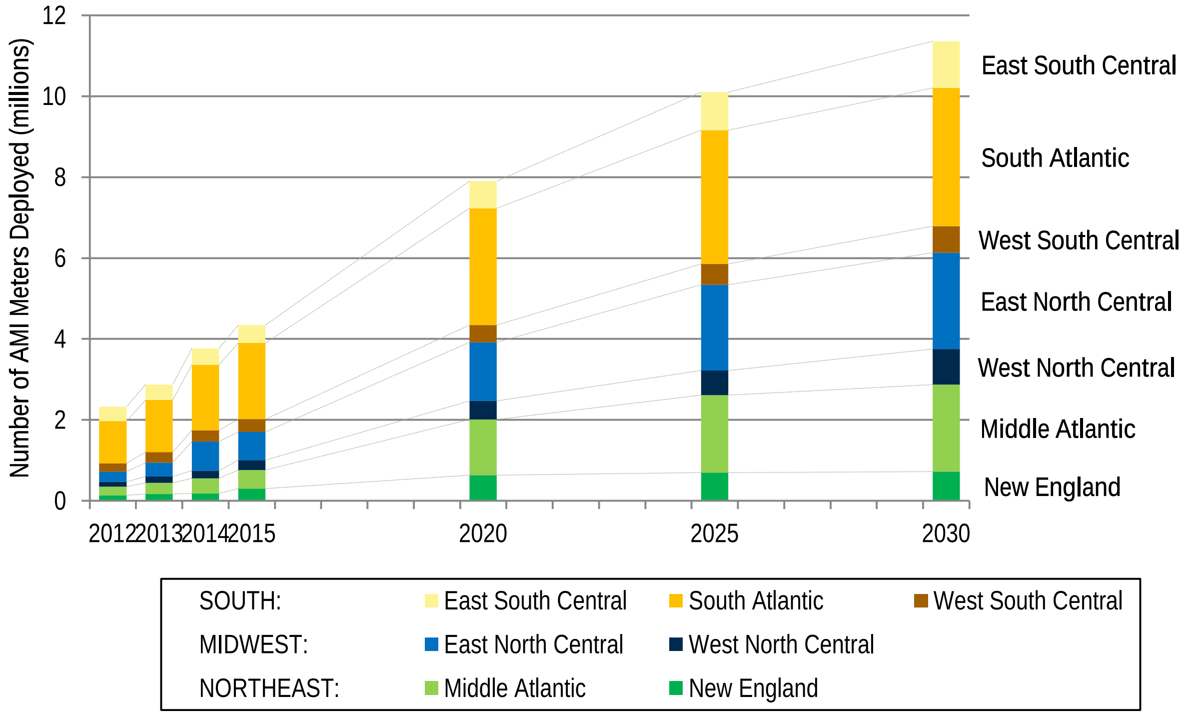


Figure 3-30. Commercial AMI Deployment by U.S. Census Region



Time-Based Rats (TBR) Programs

Table 3-35 and Table 3-36 present the current penetrations and forecasts of TBR programs in terms of resource capacity and peak load impact through 2030, aggregated by U.S. Census Region.

Table 3-35. TBR Resource Capacity by U.S. Census Region

U.S. Census Division	U.S. Census Region	TBR Resource Capacity (MW)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	33	36	37	40	215	387	483
	Middle Atlantic	154	205	266	283	1,053	1,685	2,233
Midwest	East North Central	260	316	384	505	1,179	1,744	2,211
	West North Central [a]	94	113	125	143	394	581	926
South	South Atlantic	1,134	1,213	1,317	1,417	3,088	3,775	4,379
	East South Central	18	19	21	23	513	865	1,257
	West South Central [a, b]	370	393	481	526	735	855	1,043
TOTAL		2,064	2,294	2,631	2,937	7,178	9,892	12,532

a. *Portions of both Montana and New Mexico fall within EI territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

Table 3-36. TBR Peak Load Impact by U.S. Census Region

U.S. Census Division	U.S. Census Region	TBR Peak Load Impact (MW)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	15	16	17	18	97	174	217
	Middle Atlantic	69	92	119	127	474	758	1,005
Midwest	East North Central	117	142	173	227	531	785	995
	West North Central [a]	42	51	56	64	177	261	417
South	South Atlantic	510	546	593	638	1,390	1,699	1,970
	East South Central	8	9	9	10	231	389	566
	West South Central [a, b]	166	177	217	237	331	385	469
TOTAL		929	1,032	1,184	1,322	3,230	4,451	5,639

a. *Portions of both Montana and New Mexico fall within EI territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

Refer to Appendix A for state-by-state breakdown of the TBR resource capacity and peak load impact.

Conservation Voltage Reduction (CVR) Programs
Through the data collection process, the team obtained information on 22 projects with the objective of accomplishing CVR during peak periods to reduce peak demand.

Table 3-37 and Table 3-38 present the current penetration and forecast of CVR annual energy impact and peak load impact[71] through 2030, aggregated by U.S. Census Region.

Table 3-37. CVR Annual Energy Impact by U.S. Census Region

U.S. Census Division	U.S. Census Region	Projected CVR Annual Energy Impact (GWh/yr)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	0	0	0	42	112	289	406
	Middle Atlantic	22	50	50	59	146	281	417
Midwest	East North Central	16	50	50	55	91	290	408
	West North Central [a]	110	110	115	119	311	544	710
South	South Atlantic	55	55	231	443	565	1,266	1,533
	East South Central	0	0	51	101	245	415	501
	West South Central [a, b]	0	0	22	41	102	330	435
TOTAL		203	264	519	860	1,571	3,415	4,410

a. *Portions of both Montana and New Mexico fall within Eastern Interconnection territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

[71] For the CVR portion of this assessment, Navigant assumed that resource capacity and peak load impact are equal.

Table 3-38. CVR Peak Load Impact by U.S. Census Region

U.S. Census Division	U.S. Census Region	CVR Peak Load Impact (MW)						
		2012	2013	2014	2015	2020	2025	2030
Northeast	New England	0	0	0	201	264	437	551
	Middle Atlantic	3	6	6	22	64	194	270
Midwest	East North Central	75	236	240	252	306	526	627
	West North Central [a]	11	11	13	26	115	315	435
South	South Atlantic	264	264	297	549	590	1,271	1,500
	East South Central	0	0	11	26	63	281	363
	West South Central [a, b]	0	40	45	49	80	252	329
TOTAL		353	557	612	1,124	1,481	3,276	4,075

a. *Portions of both Montana and New Mexico fall within EI territory. However, even though they are part of the Mountain Census Region, they are grouped into West North Central and West South Central, respectively, due to the proximity and small service area.*
b. *Excludes the ERCOT portion of Texas.*

Refer to Appendix A for state-by-state breakdown of the CVR resource capacity, peak load impact, and annual energy impact.

Scenario Results

Table 3-39 presents the forecast of SG resource capacity through 2030 for the Base Case and four scenarios outlined in Section 3.2.2. The team assumed that the near-term SG capacity projected for 2012 through 2015 is the same in all scenarios since to announce, receive approval, fund, design, and construct a TBR program or a CVR project requires several years of effort and changes in the key scenario drivers are unlikely to impact the market quickly enough to significantly affect SG through 2015.

Scenario 1 (with aggressive policy goals and strong economic growth) has the largest growth in SG capacity through 2030 as a result of the assumed favorable demand-side policies and technological advancements and customer adoption. The next highest scenario is Scenario 3 with aggressive policy goals and weak economic growth. Scenario 2 (with strong economic growth, relaxed policy goals, and no significant technology advancement) is the same as the Base Case because higher load growth will drive resource capacity needs, but there are no significant policy drivers or technology advancement. Scenario 4 (weak economic growth and relaxed policy goals) is lower than the Base Case because, in the absence of supporting policies, advancement in technologies, and customer adoption, the low load growth causes utilities to resist new SG investments.

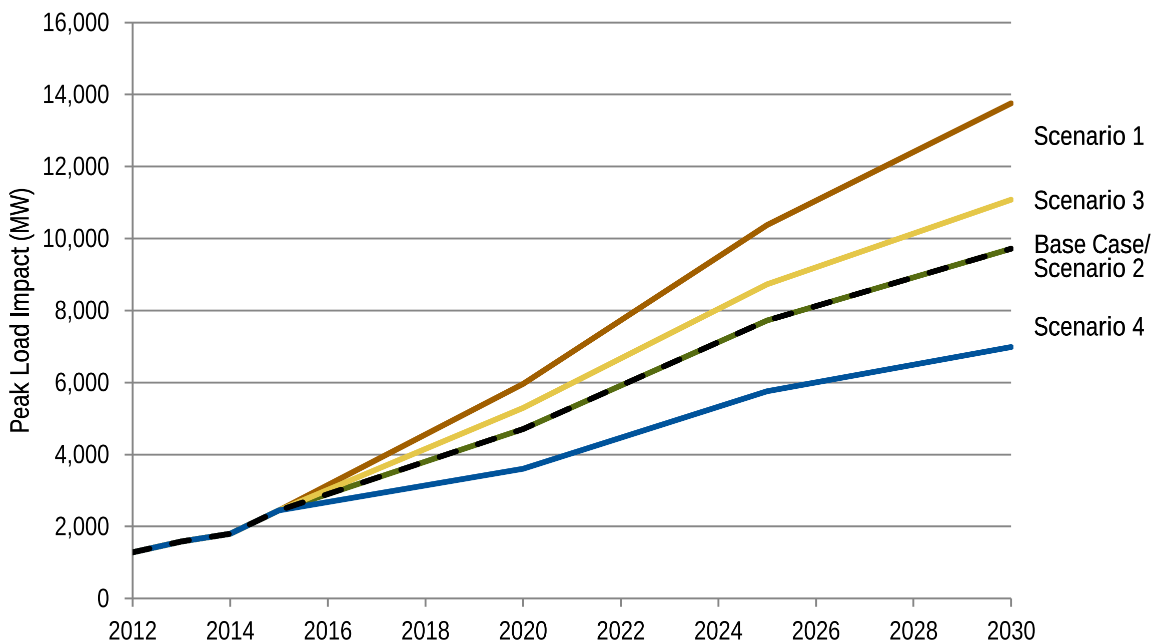
Table 3-39 presents the forecast of SG peak load impact through 2030 for the Base Case and four scenarios.

Table 3-39. Scenario Analysis of SG Peak Load Impact through 2030

Scenario	Projected SG Peak Load Impact (MW)						
	2012	2013	2014	2015	2020	2025	2030
Base Case	1,281	1,589	1,796	2,445	4,711	7,728	9,714
Scenario 1	1,281	1,589	1,796	2,445	5,966	10,377	13,754
Scenario 2	1,281	1,589	1,796	2,445	4,711	7,728	9,714
Scenario 3	1,281	1,589	1,796	2,445	5,294	8,730	11,080
Scenario 4	1,281	1,589	1,796	2,445	3,607	5,756	6,980

Figure 3-31 presents the forecast of DG-F peak load impact through 2030 in comparison to the Base Case. Scenario 1 exhibits the highest impact, whereas Scenario 4 has the smallest.

Figure 3-31. Scenario Analysis of SG Peak Load Impact through 2030



4. Combined Impact

4.1 Base Case Forecast

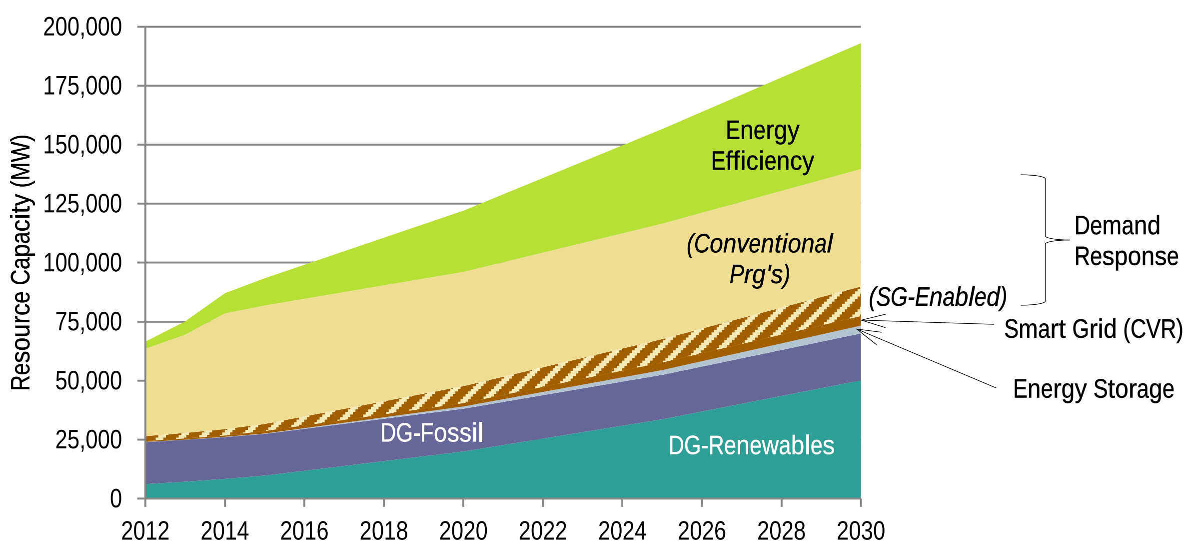
Based on the team's forecast, the total resource capacity of demand-side resources will exceed 190,000 MW by 2030. Table 4-1 and Figure 4-1 present total resource capacity of demand-side resources by resource category.

Table 4-1. Total Demand-Side Resource Capacity by Resource Category

Resource Category		Projected Total Demand-Side Resource Capacity (MW)						
		2012	2013	2014	2015	2020	2025	2030
Energy Efficiency		3,016	5,650	8,567	11,542	25,956	40,106	53,369
Demand Response	*Conventional Programs*	37,059	41,638	49,067	50,211	48,396	48,908	49,766
	*Smart Grid-Enabled**	2,064	2,294	2,631	2,937	7,178	9,892	12,532
Energy Storage		88	93	125	149	1,118	2,180	3,479
DG-Fossil		17,811	17,725	17,718	17,671	18,107	18,832	19,909
DG-Renewables		6,126	7,150	8,333	9,744	19,974	33,603	50,091
Smart Grid (CVR)		353	557	612	1,124	1,481	3,276	4,075
TOTAL		66,517	75,109	87,053	93,378	122,209	156,796	193,221

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure 4-1. Total Demand-Side Resource Capacity by Resource Category



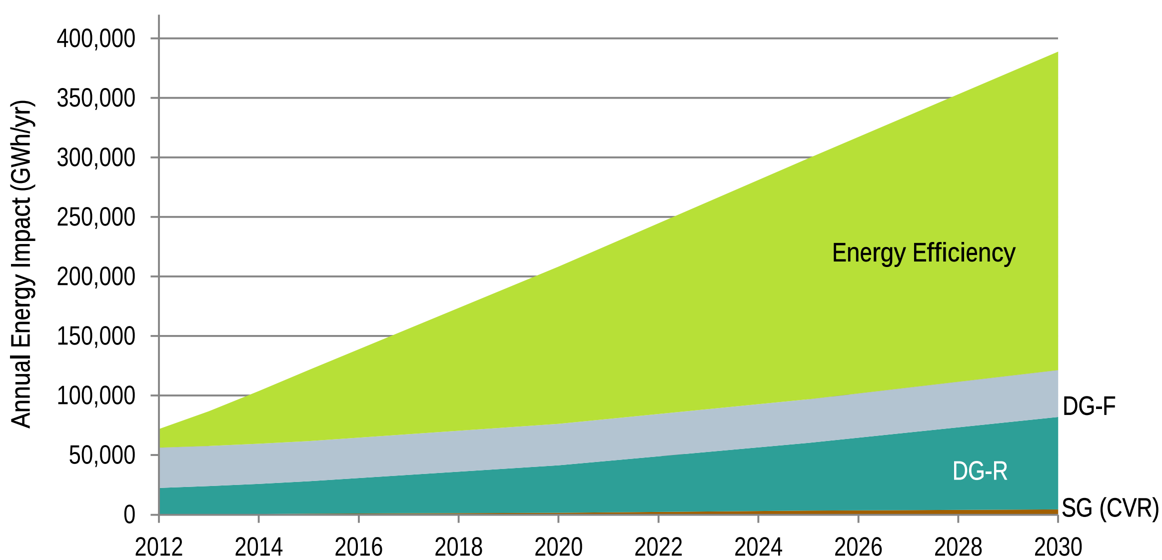
The annual energy impact of demand-side resources as a result of end-use electricity savings from energy efficiency programs, electricity generation from DG, and reduction in system losses through CVR programs will reach nearly 389,000 GWh/yr by 2030. Table 4-2 and Figure 4-2 present total annual energy impact of demand-side resources by resource category.

Table 4-2. Total Demand-Side Resource Annual Energy Impact by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	15,631	29,170	44,258	59,733	132,087	202,381	267,514
Demand Response [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	33,857	33,702	33,742	33,720	34,828	36,642	39,355
DG-Renewables	22,257	23,756	25,345	27,233	39,909	56,894	77,664
Smart Grid [a b]	203	264	519	860	1,571	3,415	4,410
TOTAL	71,948	86,893	103,864	121,546	208,396	299,332	388,943
Total Annual Electricity Consumption (AEC) [c]	*2,700,152*	*2,667,478*	*2,658,960*	*2,649,123*	*2,794,718*	*2,921,475*	*2,994,833*
% of AEC Supported by Demand-Side Resources	2.7%	3.3%	3.9%	4.6%	7.5%	10.2%	13.0%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Conservation voltage reduction programs only.*
c. *Based on 2011 electricity sales based on Form EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure 4-2. Total Demand-Side Resource Annual Energy Impact by Resource Category



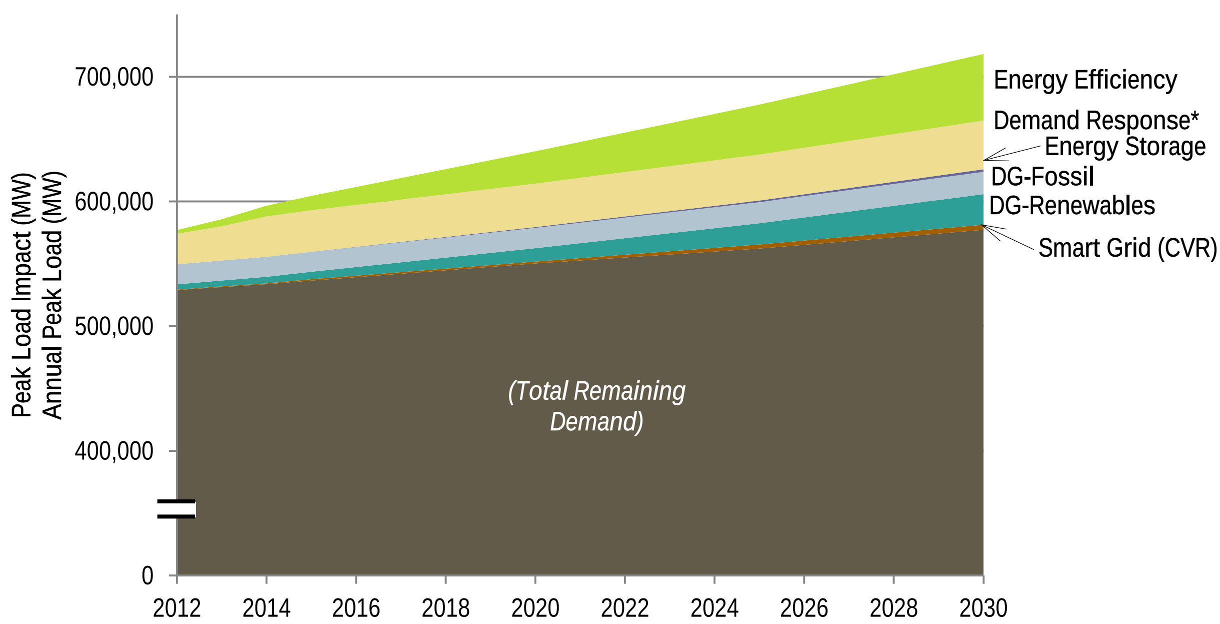
Based on this forecast, the total peak load impact of demand-side resources will exceed 140,000 MW by 2030. Table 4-3 and Figure 4-3 present total peak load impact of demand-side resources by resource category.

Table 4-3. Total Demand-Side Resource Peak Load Impact by Resource Category

Resource Category		Projected Total Demand-Side Resource Capacity (MW)						
		2012	2013	2014	2015	2020	2025	2030
Energy Efficiency		3,016	5,650	8,567	11,542	25,956	40,106	53,369
Demand Response	*Conventional Programs*	23,514	26,451	31,245	32,005	31,614	32,412	33,415
	*Smart Grid-Enabled**	929	1,032	1,184	1,322	3,230	4,451	5,639
Energy Storage		64	68	76	79	629	1,253	2,040
DG-Fossil		16,030	15,953	15,946	15,904	16,296	16,949	17,918
DG-Renewables		4,198	4,713	5,289	5,972	10,745	17,007	24,516
Smart Grid (CVR)		353	557	612	1,124	1,481	3,276	4,075
TOTAL		48,103	54,424	62,918	67,948	89,950	115,454	140,972
Total Annual Peak Load		*577,087*	*585,752*	*596,594*	*604,471*	*640,249*	*677,684*	*718,217*
% of Peak Load Supported by Demand-Side Resources		8.3%	9.3%	10.5%	11.2%	14.0%	17.0%	19.6%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure 4-3. Total Demand-Side Resource Peak Load Impact by Resource Category



Note: Includes both the conventional and smart grid-enabled programs.

4.2 Scenarios

Table 4-4 and Figure 4-4 present the forecast of demand-side resource peak load impact through 2030 for the Base Case and four scenarios as outlined in Section 2.2.3.

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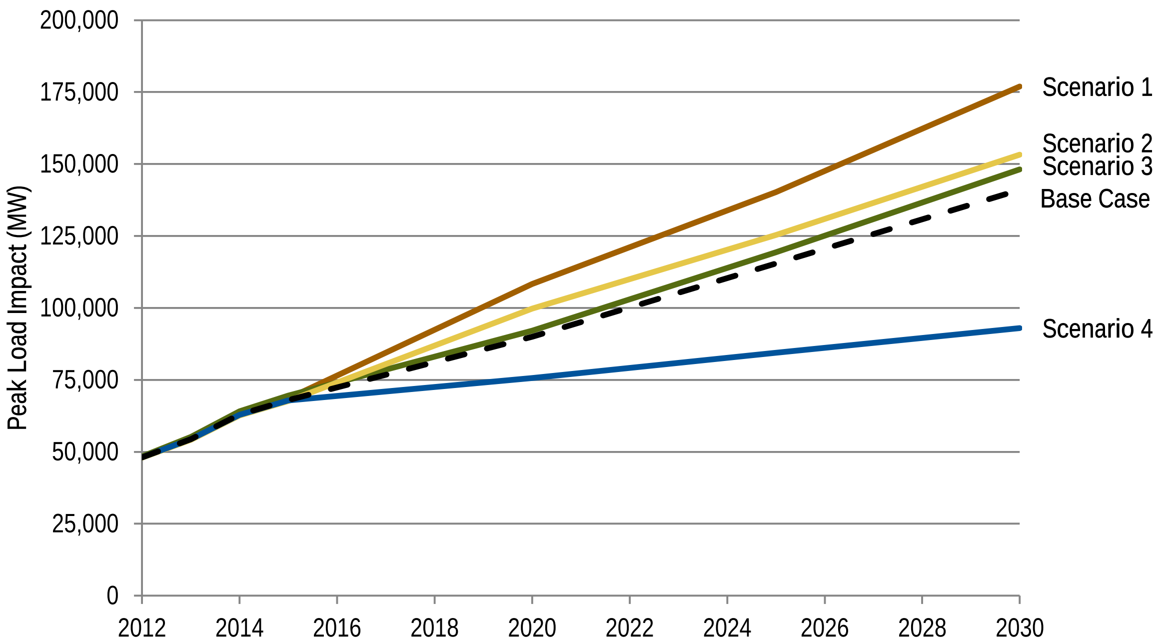
Table 4-4. Scenario Analysis of Demand-Side Resources Peak Load Impact through 2030

Scenario	Projected Demand-Side Resources Peak Load Impact (MW)						
	2012	2013	2014	2015	2020	2025	2030
Base Case	48,103	54,424	62,919	67,947	89,950	115,455	140,972
Scenario 1	48,114	54,632	63,252	68,549	108,286	140,202	176,969
Scenario 2	48,425	55,141	64,021	69,472	92,068	119,301	148,107
Scenario 3	47,948	54,211	62,605	67,652	99,721	125,286	153,192
Scenario 4	48,103	54,353	62,821	67,822	75,590	84,434	92,999

Figure 4-4. Scenario Analysis of Demand-Side Resources Peak Load Impact through 2030



4.3 *Conclusions*

In this assessment, Navigant forecasted the deployment of demand-side resources within the Eastern Interconnection through 2030. Based on the result of the forecast, several key observations emerge.

First, demand-side resources will continue to grow steadily through 2030, and will support a consideration portion of the annual electricity consumption and the peak load within the Eastern Interconnect region. By 2030, the demand-side resources will account for approximately 11% of the forecasted annual electricity consumption and nearly 20% of the total peak demand within the Eastern Interconnection[72]. Figure 4-5 and Figure 4-6 present the growth of the Annual Energy Impact and the Peak Load Impact relative to the forecasted growth electricity demand, respectively.

[72] "Total peak demand" is the sum of non-coincident peak based on NERC forecast of peak demand for assessment areas from 2012 Long-Term Reliability Assessment.

Figure 4-5. Annual Energy Impact of Demand-Side Resources Relative to Annual Electricity Consumption

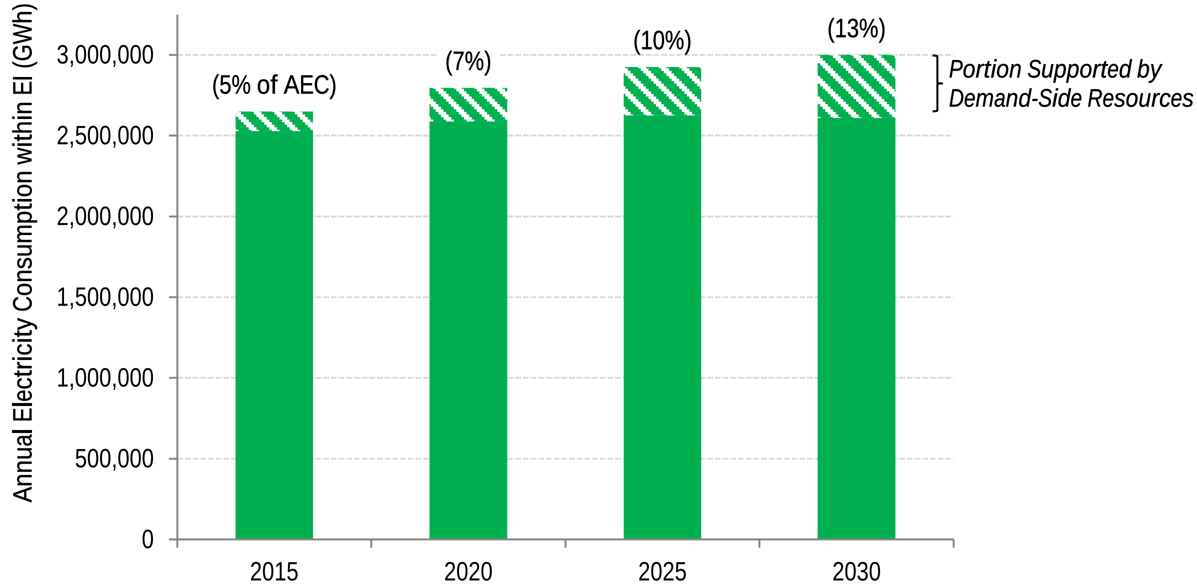
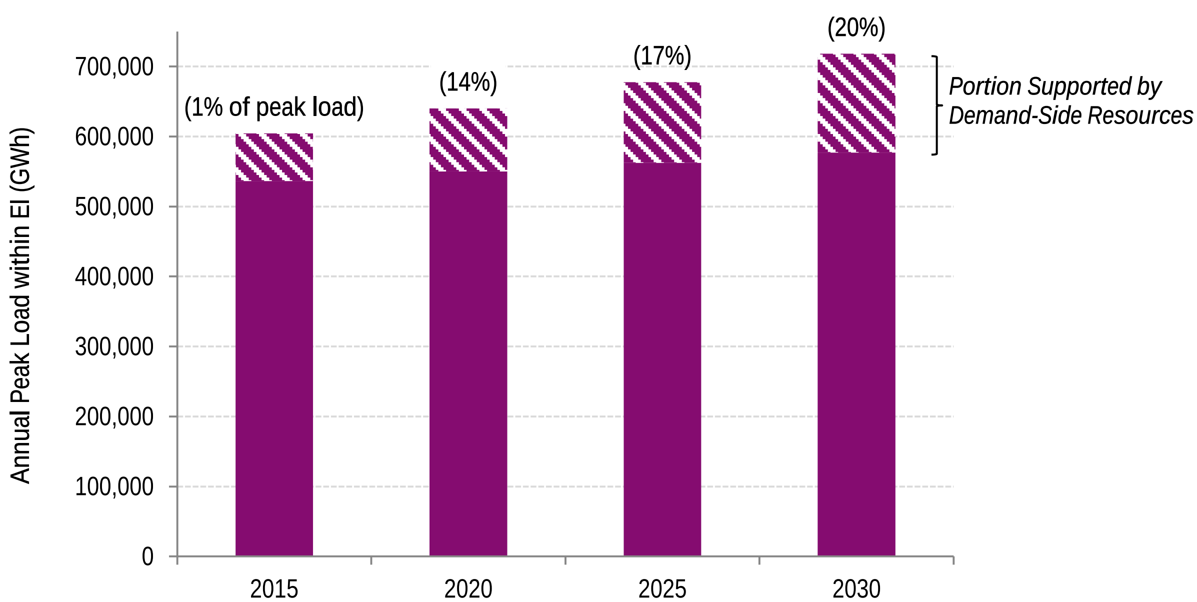


Figure 4-6. Peak Load Impact of Demand-Side Resources Relative to Annual Electricity Consumption



Second, demand-side management (DSM) programs will continue to grow as the largest contributor towards the overall peak load impact of demand-side resources. As Figure 4-7 indicates, energy efficiency programs and demand response programs (both conventional and smart grid-enabled programs) account for 57% of the total peak load impact from demand-side resources in 2012. This percentage will grow to 66% in 2030 (Figure 4-8) predominantly due to sustained long-term growth of energy efficiency programs.

Figure 4-7. Estimated Ratio of Demand-Side Resource Peak Load Impact in 2012, by Resource Category

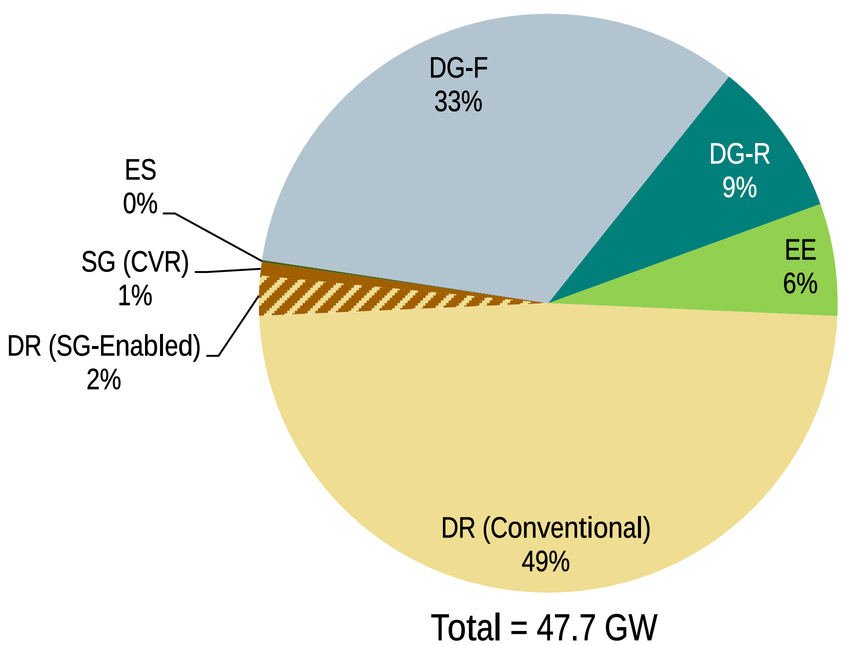
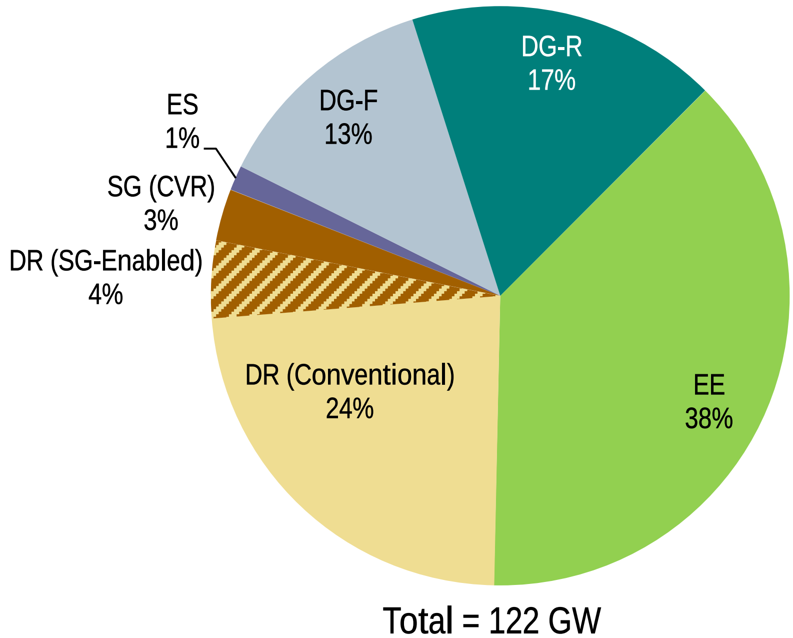


Figure 4-8. Estimated Ratio of Demand-Side Resource Peak Load Impact in 2030, by Resource Category



Third, resource categories supported by emerging technologies will exhibit the strongest growth. Table 4-5 compares the rate of growth among three groups of demand-side resources: resource that are supported by emerging technologies (i.e., smart grid-enabled DR programs, utility CVR programs, and energy storage systems); conventional DSM programs (i.e., energy efficiency and conventional demand response); and distributed generation.

Table 4-5. Compound Annual Growth Rate of Demand-Side Resources Peak Load Impact, by Resource Category Type

Resource Category Type	Projected Demand-Side Resources Peak Load Impact (MW)		
	2012	2030	Compound Annual Growth Rate, 2012-2030
Resources supported by emerging technologies[a]	1,345	11,754	12.8%
Conventional DSM programs[b]	26,530	86,784	6.8%
Distributed generation[c]	20,228	42,434	4.2%

a. *Includes smart grid-enabled DR programs, utility CVR programs, and energy storage.*
b. *Includes energy efficiency and conventional demand response programs.*
c. *Includes DG-Fossil and DG-Renewables.*

The total peak load impact of smart grid-enabled time-based rate programs, advanced utility CVR programs, and energy storage will increase by a factor of 9 between 2012 and 2030. This rate of growth is nearly three times as fast as that of conventional DSM programs.

Finally, energy policies and retail electricity prices are the two market drivers likely to have the strongest influence on the growth in adoption of demand-side resources. In Scenario 1 (with strong economic growth and aggressive policy goals), policies that encourage implementation of DSM program and penalties on greenhouse gas emissions provide a significant boost to the forecasted adoption of EE, DR and DG-R, resulting in a nearly 26% increase in peak load impact relative to the Base Case. In comparison, the absence of supporting policies paired with the low retail electricity prices in Scenario 4 (with weak economic growth and relaxed energy policy goals) lead to resistance to new investments in utility DSM programs and DG-R.

5. Recommendations for Future Work

During the course of this assessment, Navigant encountered several issues that, in the team's view, warrant further investigation. There are three types of issues: definitions of resource terminology; possible overlaps and double-counting of resources; and gaps in publicly available data.

5.1 *Definitions of Demand-Side Resource Terminology*

5.1.1 Definition of Demand Response Capacity

During the course of the stakeholder interviews, Navigant discovered that there is a lack of consistency in how different entities define DR capacity. For example, one of the FERC DR survey respondents had responded to FERC's question on potential peak reduction with the total customer load enrolled in the program, rather than the amount of load available for reduction. In this particular case, this discrepancy led to an order-of-magnitude difference in reported capacity.

DR capacity can be captured as the total load of a participating customer, the amount of load the customer has available to reduce during peak times, the amount of load the customer is actually asked to reduce during a specific event, and the amount the customer actually reduces during a specific event. Having more data available on the amount of load available for reduction during peak versus the amount actually reduced will help give transmission planners greater confidence in the peak demand impact from DR. Navigant recommends that NARUC coordinates with FERC to revisit the names and definitions of "Maximum Demand of Customers", "Potential Peak Reduction", and "Realized Demand Reduction" for future surveys to more explicitly discuss these different dimensions and minimize respondent confusion.

On a related note, the DR programs of public power utilities are often primarily operated to manage the costs of their customers and may not be available to help reduce transmission congestion issues. Navigant recommends NARUC to consider the DR resource capacity available from public power on a discounted basis for transmission planning purposes.

5.1.2 Definition of Smart Meters

There is a general lack of consistency in how different entities define "smart meters". The definitions appear to range from AMR meters, which are digital meters with automated meter reading capability, to AMI meters, which are digital meters with two-way communication capability and other additional functionalities, such as outage notification, and voltage monitoring. While processing the Form EIA-861 data to determine AMI meter deployment, Navigant identified instances where some respondents reported their AMR meters as "advanced meter"[73].

Any digital meters are likely to be more advanced in functionality compared to analog electromechanical meters. However, in order for utilities to introduce time-based rate programs, their meters must have two-way communication capability as well as interval reading capability. Navigant recommends that

[73] Refer to Section 3.6.3 for the FERC definition of advanced meter.

NARUC coordinates with FERC to revisit how "advanced meters" is defined, and ensure that this definition is recognized and strictly observed for future surveys and other data collection efforts. This may require a separate effort to work with appropriate stakeholders to agree on a set of multiple definitions based on functionality (i.e., combinations of features such as automated meter reading, power quality monitoring, and remote service switching) that different meter products offer.

5.1.3 Definition of Distributed Generation

Currently, there is no consistent definition of "distributed generation" that is recognized across the industry. For the purpose of this report, Navigant defined distributed generation by the range of gross output capacity (for fossil-based DG) or nameplate capacity (for renewable DG). However, the way owners operate these generators may depend more on the primary application than on the size. Navigant recommends NARUC to coordinate with appropriate industry stakeholder, including U.S. DOE, to develop a definition of DG. This definition should include specifications on size, which may need to vary based on application (e.g., backup, peaking, and additional power) and by resource type (i.e., fossil fuel-based or renewable-based).

5.2 *Overlaps and Double-Counting of Resources*

5.2.1 Conventional Demand-Side Management Programs and Utility Load Forecasts

Some demand-side management (DSM) programs, such as industrial time-of-use rates, are widely adopted by utilities across the U.S. In many cases, a utility's load forecast already account for the impact of these DSM programs. Navigant recommends NARUC to coordinate with FERC and other stakeholders to ensure that future surveys and data collection efforts request respondents to only provide savings from DSM programs not already included in their energy sales and load forecasts reported to EIA and NERC.

5.2.2 Incremental versus Cumulative Savings from Energy Efficiency Programs

During the data collection phase of the assessment, Navigant often encountered utilities reporting energy savings from energy efficiency programs in inconsistent manners. Specifically, utilities can report the savings as either annual incremental savings, which capture only the new savings from a program in that year, or cumulative savings, which include the new savings in that year as well as the savings achieved over the life of that program in previous years. Variations and ambiguity in how utilities report incremental versus cumulative savings make it challenging to determine the total amount of new energy savings that should be considered in transmission planning.

While the EIA definitions of Incremental and Annual Effects do attempt to capture this difference in Form EIA-861, the wide variance on the way utilities report these effects may warrant additional refinements to more succinctly and narrowly request the desired response. Navigant recommends changing the term "Annual Effects" to "Annual Cumulative Effects" and modifying the definition to ask for the cumulative estimated savings from DSM programs in a given year that are not included in the company's reported energy sales and load forecasts. Navigant also recommends defining the Incremental Effects as all new savings in that year, from both new and existing programs, such that the sum of the Annual Effects reported in the previous year, plus the current year's Incremental Effects equal the Annual Effects in the current year.

5.2.3 Concurrent Enrollments in Multiple DR Programs

Another potential double-counting issue, particularly for DR programs, is when a customer participates in DR programs at both the wholesale and retail levels, and their reduction is reported by both entities. Examples of this include participation in a utility's program and an ISO/RTO market, or through a wholesaler like a generation and transmission cooperative or curtailment service provider. Similarly, a potential for double-counting also exists when a customer can enroll the same load in more than one program (e.g., an Economic and an Emergency programs offered by an ISO/RTO) and the load is counted for both.

FERC has started to address this issue by requesting retail entities to report the potential peak reduction enrolled in ISO/RTO programs. To further reduce the potential for double-counting, Navigant recommends NARUC to coordinate with FERC and other stakeholder to ensure that future surveys and data collection efforts ask more generally for the amount of a retail entity's peak reduction enrolled in a wholesale market or through a wholesale provider, as well as for the estimated amount of load that participates in more than one program.

5.3 Significant Data Gaps

Encountering gaps in publicly available data is a common challenge in studies that involve long-term adoption forecasts. However, Navigant identified four major gaps in data that may significantly improve the quality of the forecast if addressed.

5.3.1 Impact of Smart Grid Deployment on Overall DR Market Trend

As discussed in Section 3.2.2, Navigant observed slowing growth of DR as a general trend past 2015. This trend is indicated in the IRPs and other collected DR forecasts, and is also consistent with the "Optimistic BAU" case in Oak Ridge National Laboratory's *Eastern Interconnection Demand Response Potential* study, which shows DR growth leveling off to match demand growth in about the same timeframe.

Although there are undoubtedly many factors that influence the market trend in DR, the IRPs and other collected DR forecasts may not fully take into account the deployment of enabling technologies that might facilitate broader rollout of DR programs. Particularly, the deployment of AMI meters will provide an avenue for utilities to introduce time-based rate programs to residential and small commercial customer classes, which currently play smaller roles in conventional DR programs than the larger commercial and industrial classes.

Given the lack of publicly available studies and forecasts that analyze this issue in depth, this study assumes that the overall DR program trend will not deviate from what the IRPs and other collected DR forecast, and that the impact of smart grid will not significantly influence this trend. However, Navigant recommends NARUC continue to monitor any development in DR market trends that increased smart grid deployment may impact.

5.3.2 Coincidence of Demand Reduction from DR Programs

Currently, there is minimal data available to determine the coincidence of demand reductions from DR programs. Navigant recommends NARUC to coordinate with FERC to ensure that respondents for future surveys provide both winter and summer peak impacts from DR programs. Furthermore, Navigant recommends FERC add the word "peak" to "Maximum demand of customers" and "Realized demand reduction" in the FERC survey, and ask for the demand reductions coincident with the utility or system peak.

5.3.3 DG Adoption Tracked by Utilities

Currently, there is minimal data available on the penetration of backup/emergency generators used for DR. This due to the fact that data on existing DG is generally not tracked by utilities, state energy offices, or regional reliability entities. Typically, DG units owned and operated by non-utility owners are being used as backup, peaking, or for additional power. Without this information, it is difficult to determine the relative capacities of DR and DG without potentially double-counting capacity. Navigant recommends NARUC to coordinate with NERC, FERC, and EIA to ensure that future surveys and data collection efforts cover topics pertaining DG, including estimates of the percentage of their reported DR capacity supported by from DG. Navigant also recommends NARUC work with FERC to further develop a comprehensive database on existing DG.

5.3.4 Adoption and Impact of Smart Grid Programs

Currently, the data pertaining to time-based rate programs and enhanced CVR programs are scarce, mainly because they are still in an early stage of adoption across the U.S. For example, many utilities are not tracking the impact of their smart grid-enabled time-based rate programs if they are implementing the programs as a small-scale pilot. Navigant recommends NARUC continue to work with utilities and other stakeholders to better understand how these smart grid-enabled programs are adopted, and what strategic objectives they address.

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Appendix A. State-Level Forecast Results

This section includes the forecast results by resource category for each of the U.S. Eastern Interconnect entities. Note that this analysis is based represents a bottom-up estimate and forecast based on Navigant's expert review of publicly and commercially available information.

A.1 Alabama

Table A-1. Projected Demand-Side Resource Capacity in Alabama through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	17	33	51	68	172	290	406
Demand Response (conventional)	1,614	1,694	1,924	1,964	1,874	1,954	2,033
Demand Response (smart grid-enabled)*	2	2	2	2	222	295	373
Energy Storage	0	0	0	0	34	73	121
DG-Fossil	224	227	231	234	277	326	383
DG-Renewables	21	22	22	23	24	27	29
Smart Grid (CVR)	0	0	0	200	200	302	337
TOTAL	1,878	1,978	2,229	2,491	2,803	3,267	3,682

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-1. Projected Demand-Side Resource Capacity in Alabama through 2030

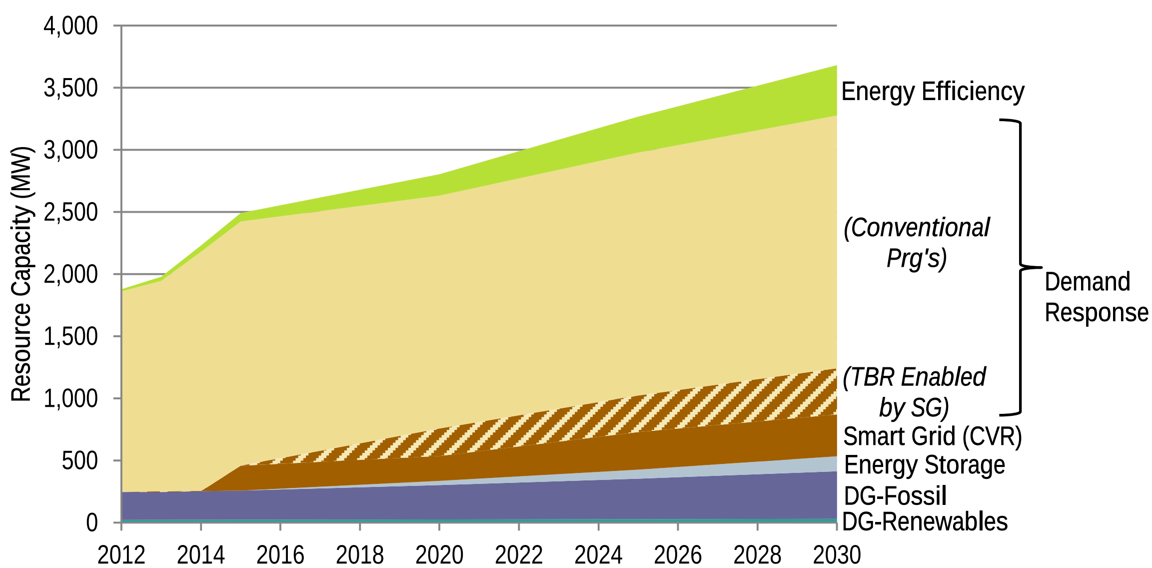


Table A-2. Projected Demand-Side Resource Annual Energy Impact in Alabama through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	73	143	216	292	737	1,238	1,734
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	744	757	770	783	920	1,080	1,268
DG-Renewables	117	121	123	126	135	148	165
Smart Grid [a c]	0	0	0	42	42	140	177
TOTAL	935	1,020	1,109	1,243	1,834	2,607	3,344
Total Annual Electricity Consumption (AEC) [d]	86,757	82,085	84,087	82,753	88,537	94,320	96,767
% of AEC Supported by Demand-Side Resources	1.1%	1.2%	1.3%	1.5%	2.1%	2.8%	3.5%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-2. Projected Demand-Side Resource Annual Energy Impact in Alabama through 2030

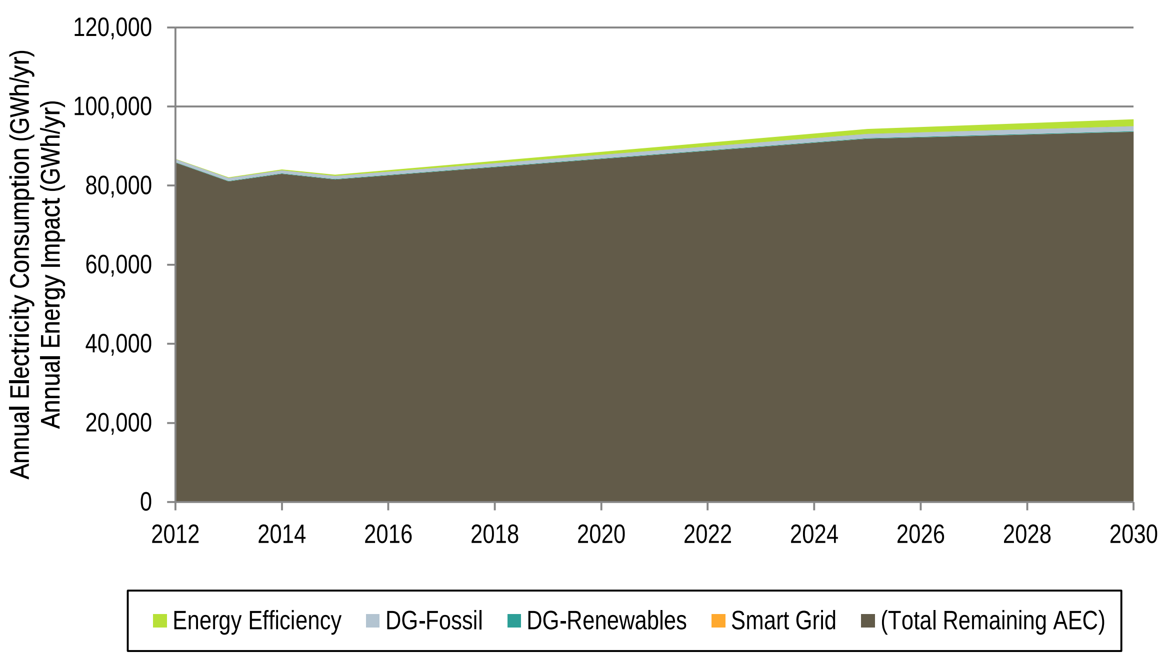
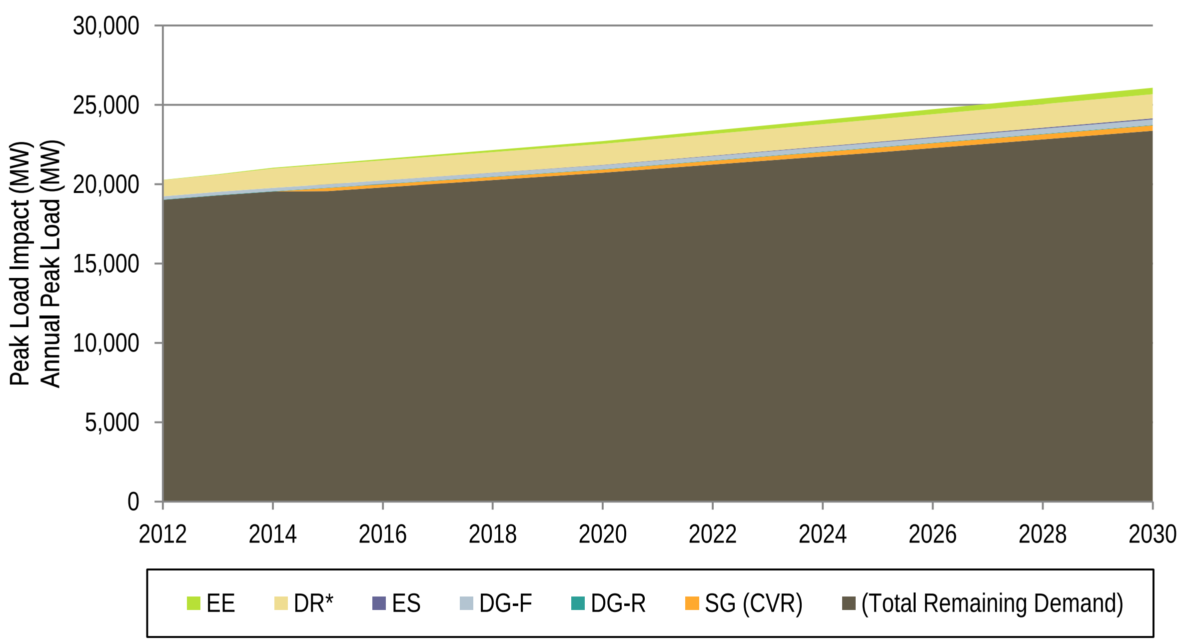


Table A-3. Projected Demand-Side Resource Peak Load Impact in Alabama through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	17	33	51	68	172	290	406
Demand Response (conventional)	1,022	1,072	1,218	1,243	1,226	1,291	1,355
Demand Response (smart grid-enabled)*	1	1	1	1	100	133	168
Energy Storage	0	0	0	0	20	43	72
DG-Fossil	202	205	208	211	249	293	345
DG-Renewables	21	22	22	23	24	27	29
Smart Grid (CVR)	0	0	0	200	200	302	337
TOTAL	1,262	1,333	1,499	1,746	1,992	2,378	2,711
Total Annual Peak Load	20,274	20,625	21,035	21,308	22,715	24,383	26,077
% of Peak Load Supported by Demand-Side Resources	6.2%	6.5%	7.1%	8.2%	8.8%	9.8%	10.4%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-3. Projected Demand-Side Resource Peak Load Impact in Alabama through 2030



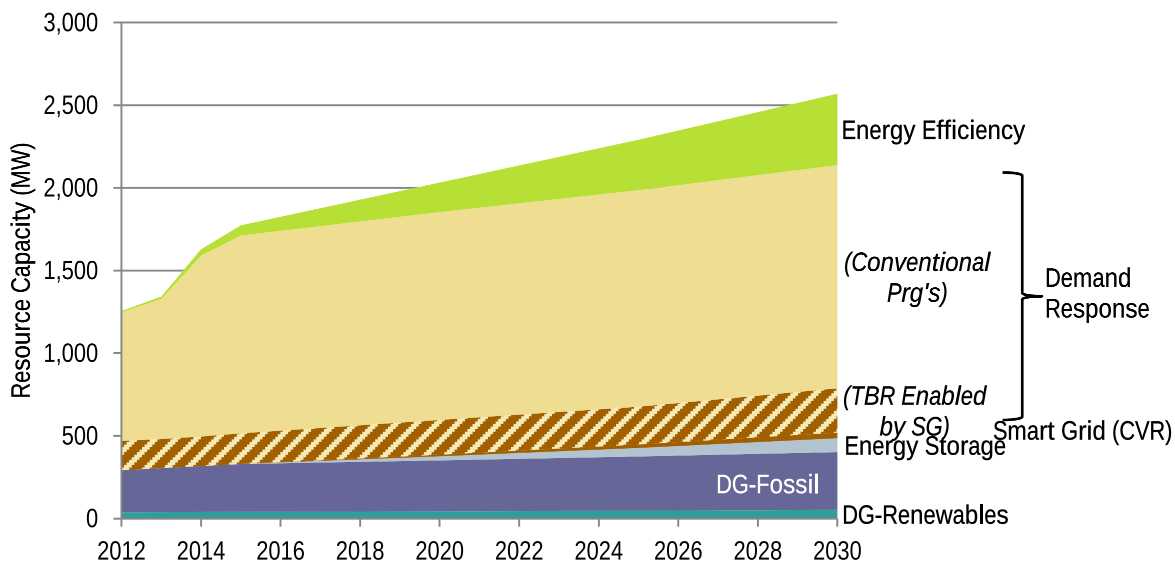
Note: "DR" include both the conventional and smart grid-enabled programs.

A.2 Arkansas[74]

Table A-4. Projected Demand-Side Resource Capacity in Arkansas through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	7	15	39	62	179	305	432
Demand Response (conventional)	780	846	1,094	1,197	1,257	1,309	1,350
Demand Response (smart grid-enabled)*	177	177	178	185	210	228	268
Energy Storage	0	0	0	0	24	51	84
DG-Fossil	254	266	278	289	308	328	349
DG-Renewables	38	39	40	40	43	47	52
Smart Grid (CVR)	0	0	0	0	10	22	34
TOTAL	1,255	1,342	1,628	1,773	2,032	2,291	2,569
** Includes time-based rate programs that require AMI meters with two-way communication capability.*							

Figure A-4. Projected Demand-Side Resource Capacity in Arkansas through 2030



[74] The forecast for Arkansas assumes that the 2012 EE data available for Empire District Electric Company and Oklahoma Gas & Electric Company are cumulative. Navigant used 2011 EIA-861 data to estimate the incremental annual savings achieved in 2012.

Table A-5. Projected Demand-Side Resource Annual Energy Impact in Arkansas through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	32	73	183	292	848	1,449	2,050
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	480	509	538	567	620	674	729
DG-Renewables	213	219	223	228	245	269	300
Smart Grid [a c]	0	0	0	0	7	16	24
TOTAL	725	801	944	1,088	1,721	2,407	3,103
Total Annual Electricity Consumption (AEC) [d]	47,370	45,639	46,268	46,819	48,078	49,888	50,675
% of AEC Supported by Demand-Side Resources	1.5%	1.8%	2.0%	2.3%	3.6%	4.8%	6.1%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-5. Projected Demand-Side Resource Annual Energy Impact in Arkansas through 2030

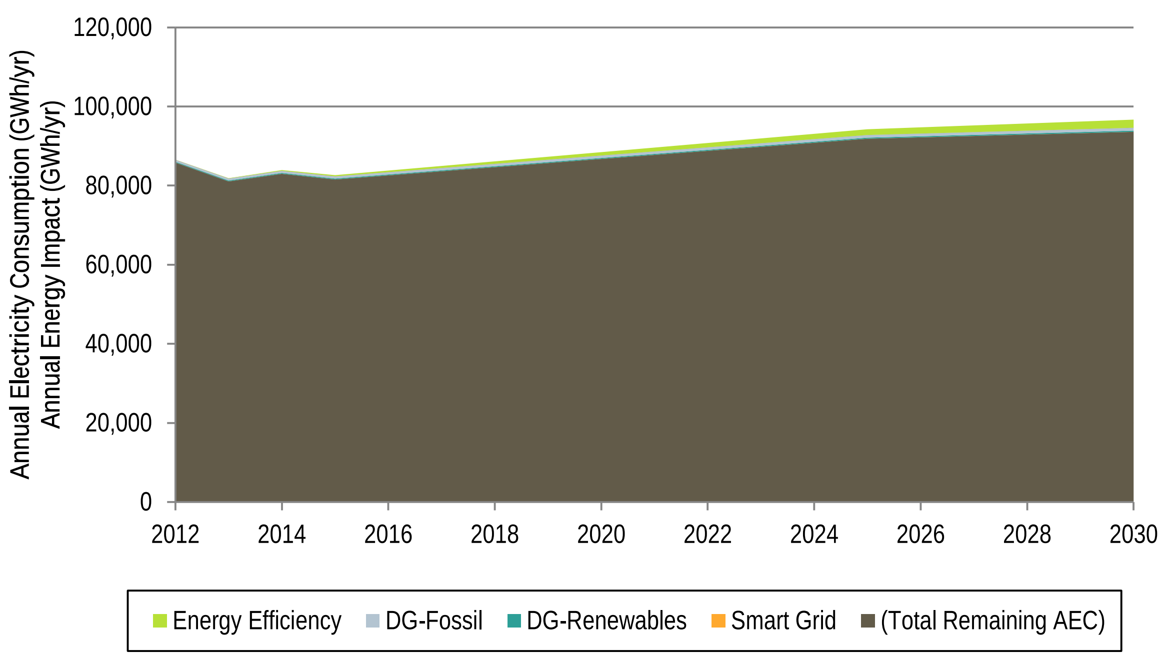
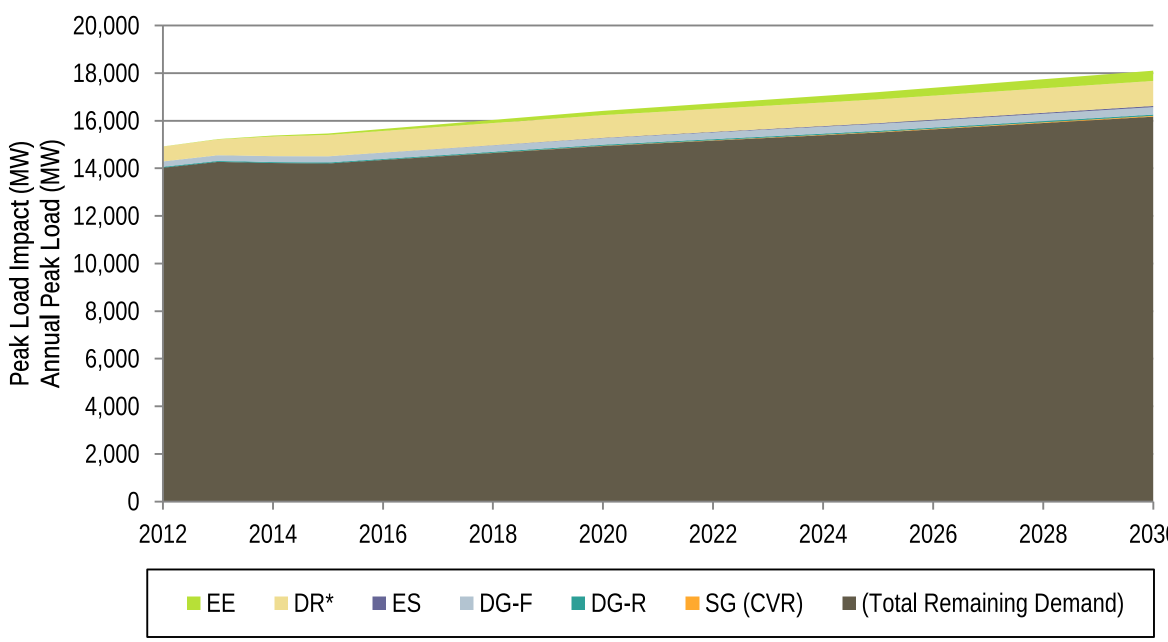


Table A-6. Projected Demand-Side Resource Peak Load Impact in Arkansas through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	7	15	39	62	179	305	432
Demand Response (conventional)	542	585	746	814	859	896	931
Demand Response (smart grid-enabled)*	80	80	80	83	94	103	120
Energy Storage	0	0	0	0	14	30	50
DG-Fossil	229	239	250	260	277	295	314
DG-Renewables	38	39	39	40	43	47	52
Smart Grid (CVR)	0	0	0	0	10	22	34
TOTAL	895	957	1,154	1,260	1,477	1,698	1,933
Total Annual Peak Load	14,918	15,227	15,377	15,463	16,413	17,202	18,102
% of Peak Load Supported by Demand-Side Resources	6.0%	6.3%	7.5%	8.1%	9.0%	9.9%	10.7%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-6. Projected Demand-Side Resource Peak Load Impact in Arkansas through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

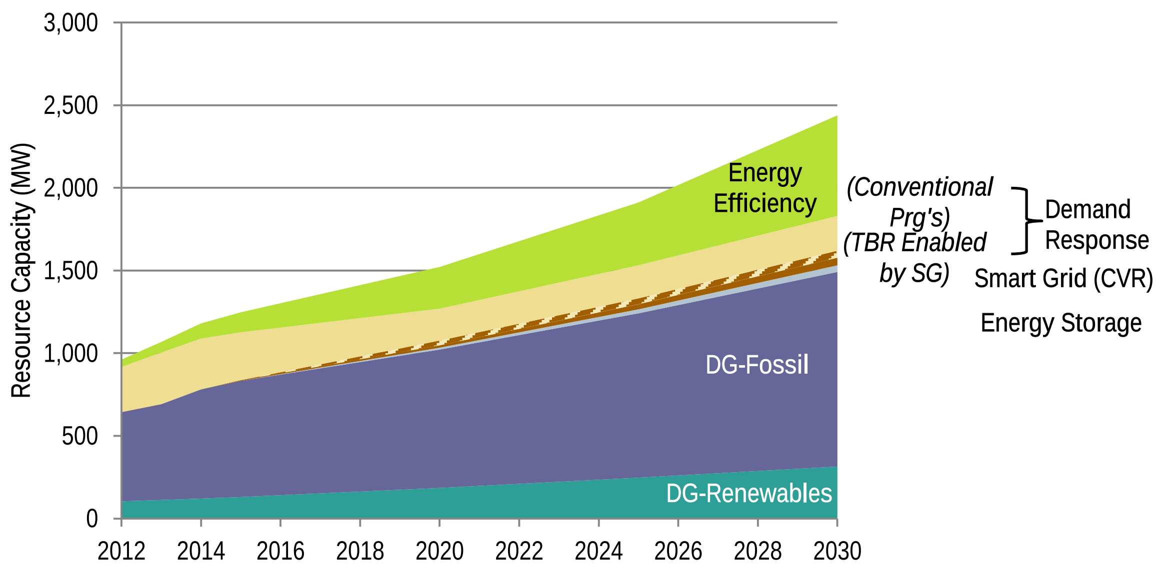
A.3 Connecticut[75]

Table A-7. Projected Demand-Side Resource Capacity in Connecticut through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	44	64	92	121	252	380	609
Demand Response (conventional)	273	312	307	289	193	200	210
Demand Response (smart grid-enabled)*	0	0	0	0	29	36	43
Energy Storage	0	0	0	0	11	24	40
DG-Fossil	539	579	660	702	837	994	1,177
DG-Renewables	104	112	121	130	185	247	314
Smart Grid (CVR)	0	0	0	4	14	31	46
TOTAL	961	1,068	1,180	1,247	1,521	1,912	2,439

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-7. Projected Demand-Side Resource Capacity in Connecticut through 2030



75 EE and DR forecasts are based on ISO-NE's 2012 Forecast Data File.

Table A-8. Projected Demand-Side Resource Annual Energy Impact in Connecticut through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	370	533	763	1,007	2,099	3,160	5,065
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	887	978	1,167	1,265	1,604	1,999	2,458
DG-Renewables	355	367	380	393	469	558	655
Smart Grid [a c]	0	0	0	2	10	22	45
TOTAL	1,612	1,878	2,310	2,667	4,182	5,739	8,223
Total Annual Electricity Consumption (AEC) [d]	30,101	30,360	30,620	30,360	31,139	31,917	31,658
% of AEC Supported by Demand-Side Resources	5.4%	6.2%	7.5%	8.8%	13.4%	18.0%	26.0%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-8. Projected Demand-Side Resource Annual Energy Impact in Connecticut through 2030

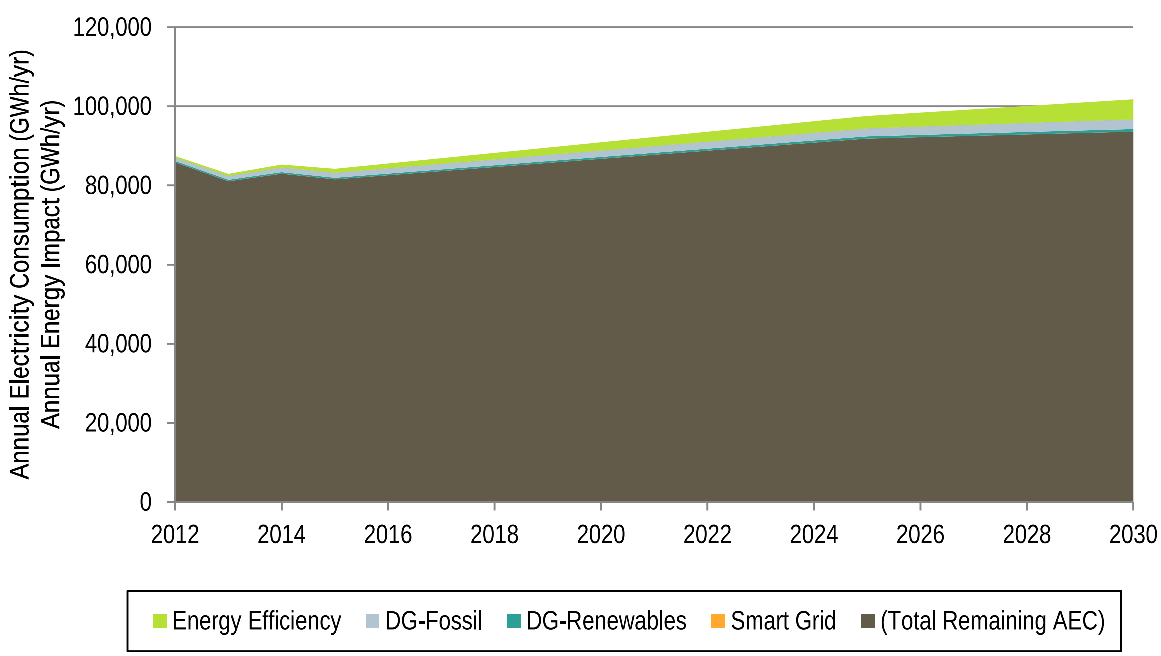
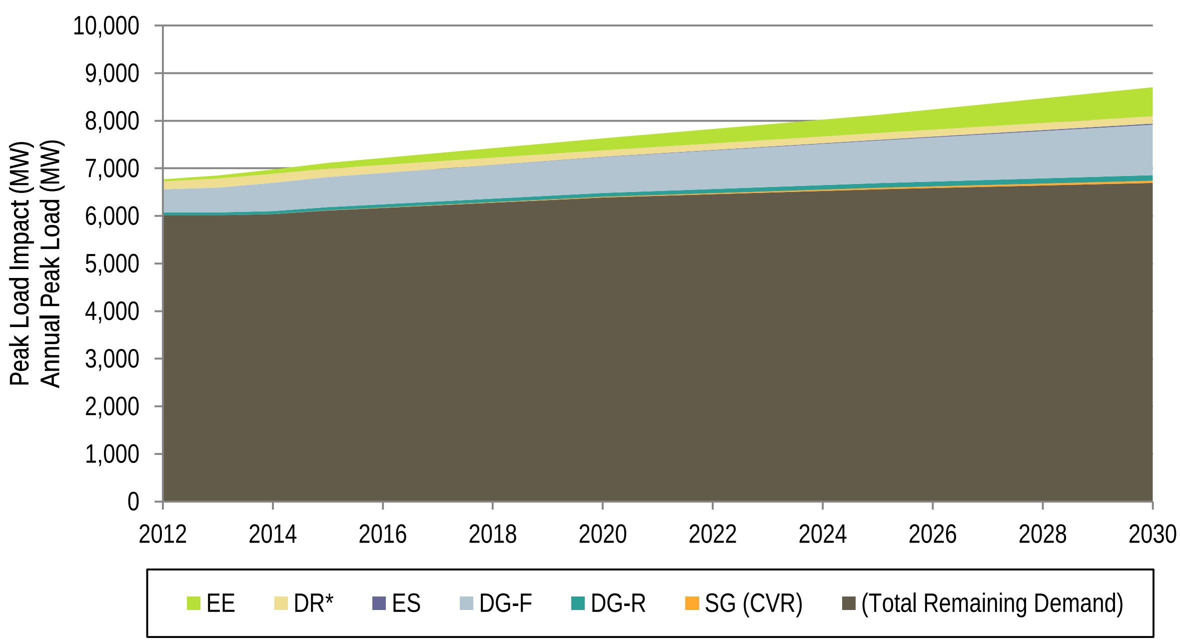


Table A-9. Projected Demand-Side Resource Peak Load Impact in Connecticut through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	44	64	92	121	252	380	609
Demand Response (conventional)	166	190	187	176	122	128	134
Demand Response (smart grid-enabled)*	0	0	0	0	13	16	19
Energy Storage	0	0	0	0	7	14	24
DG-Fossil	485	521	594	632	753	894	1,059
DG-Renewables	59	62	64	67	82	99	118
Smart Grid (CVR)	0	0	0	4	14	31	46
TOTAL	755	837	937	1,000	1,243	1,562	2,009
Total Annual Peak Load	6,769	6,849	6,975	7,114	7,629	8,121	8,702
% of Peak Load Supported by Demand-Side Resources	11.2%	12.2%	13.4%	14.1%	16.3%	19.2%	23.1%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-9. Projected Demand-Side Resource Peak Load Impact in Connecticut through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

A.4 Delaware

Table A-10. Projected Demand-Side Resource Capacity in Delaware through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	2	12	17	23	59	97	135
Demand Response (conventional)	151	216	307	306	305	321	343
Demand Response (smart grid-enabled)*	100	100	103	106	131	142	149
Energy Storage	0	0	0	0	4	9	15
DG-Fossil	113	113	112	111	102	94	86
DG-Renewables	61	88	119	154	386	667	984
Smart Grid (CVR)	0	0	0	0	2	4	6
TOTAL	426	529	658	701	990	1,333	1,718

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-10. Projected Demand-Side Resource Capacity in Delaware through 2030

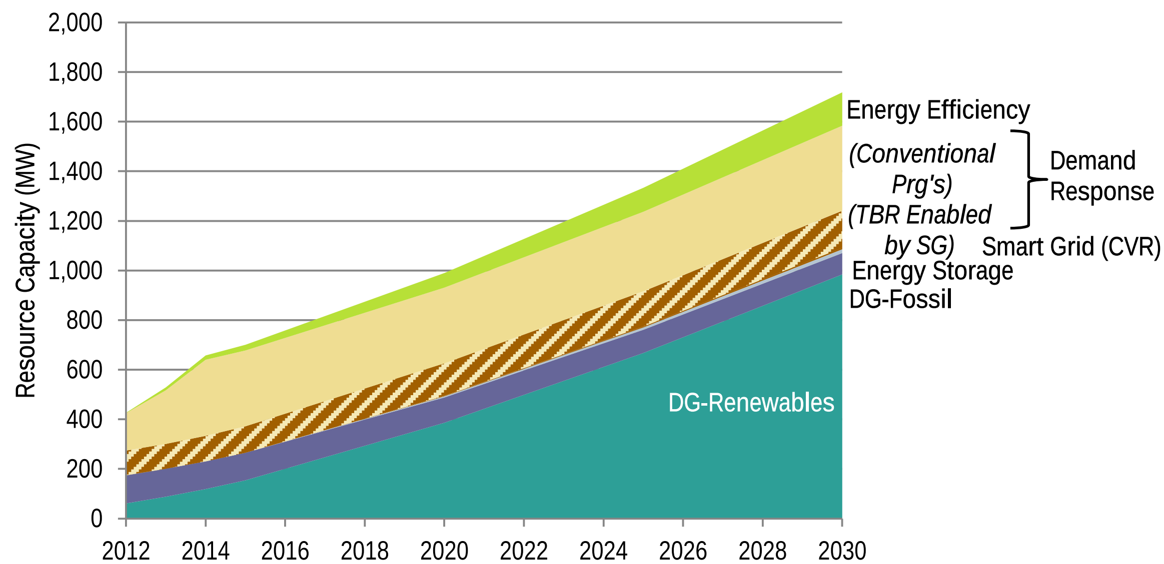


Table A-11. Projected Demand-Side Resource Annual Energy Impact in Delaware through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	11	82	120	159	406	667	929
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	260	259	258	257	249	242	235
DG-Renewables	125	161	202	248	549	915	1,329
Smart Grid [a c]	0	0	0	0	2	4	6
TOTAL	396	502	580	664	1,207	1,828	2,499
Total Annual Electricity Consumption (AEC) [d]	11,499	11,356	11,499	11,214	12,481	13,082	13,383
% of AEC Supported by Demand-Side Resources	3.4%	4.4%	5.0%	5.9%	9.7%	14.0%	18.7%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-11. Projected Demand-Side Resource Annual Energy Impact in Delaware through 2030

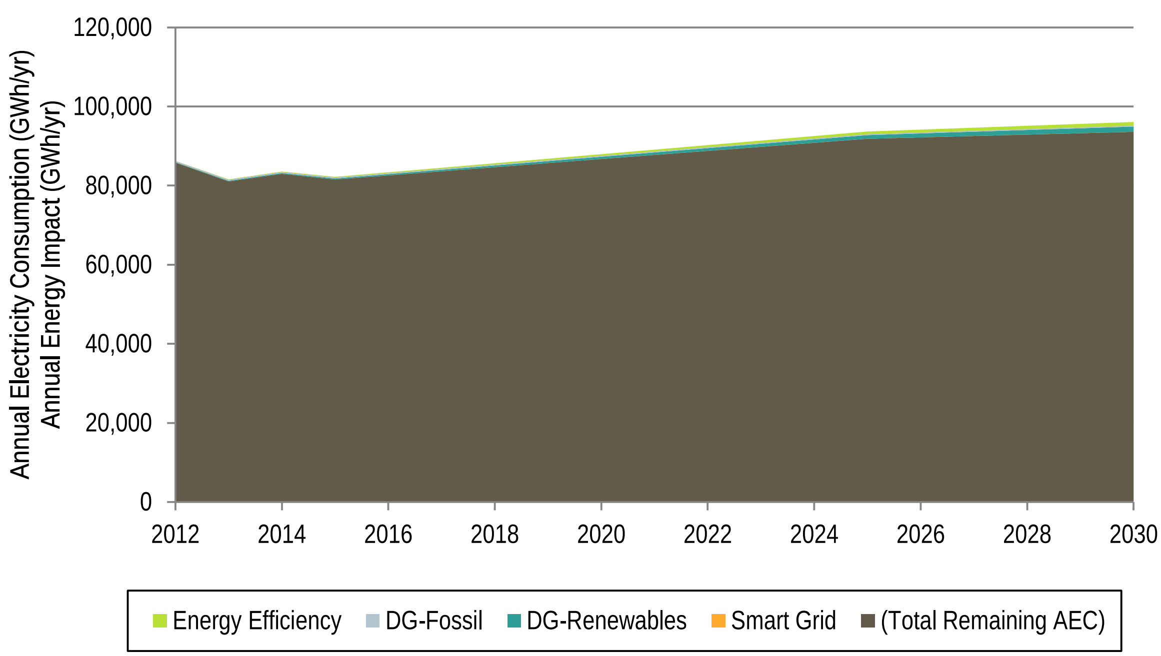
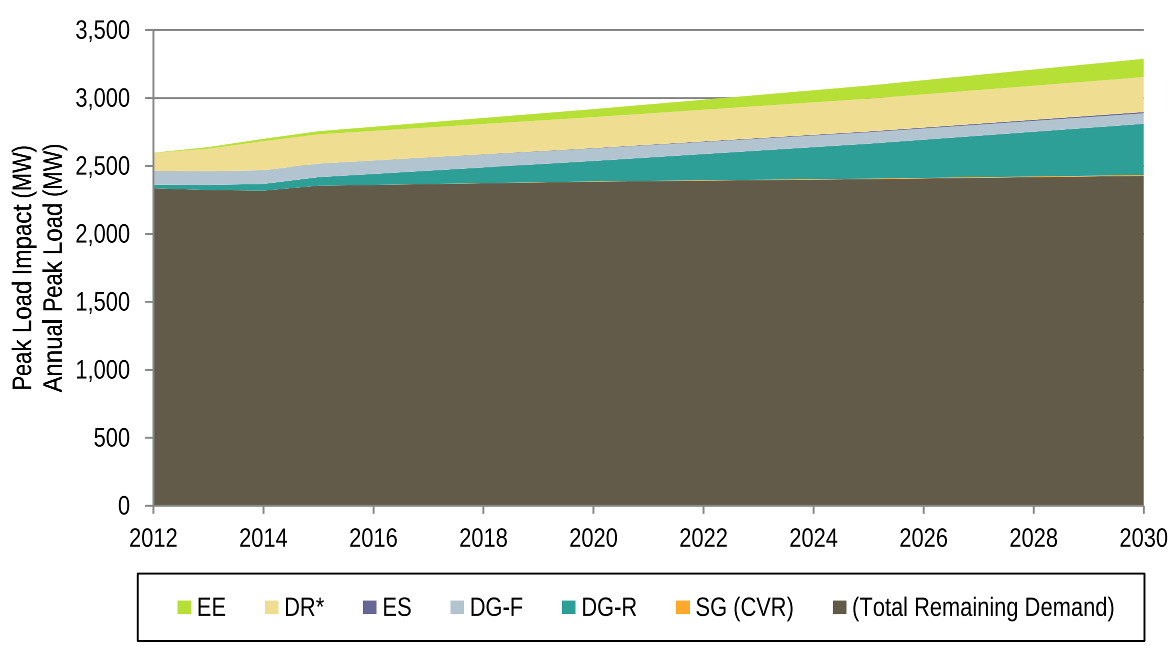


Table A-12. Projected Demand-Side Resource Peak Load Impact in Delaware through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	2	12	17	23	59	97	135
Demand Response (conventional)	86	120	168	168	169	178	190
Demand Response (smart grid-enabled)*	45	45	46	48	59	64	67
Energy Storage	0	0	0	0	3	5	9
DG-Fossil	102	101	101	100	92	84	78
DG-Renewables	27	38	49	63	150	257	376
Smart Grid (CVR)	0	0	0	0	2	4	6
TOTAL	262	316	382	402	534	689	861
Total Annual Peak Load	2,597	2,638	2,699	2,755	2,918	3,091	3,288
% of Peak Load Supported by Demand-Side Resources	10.1%	12.0%	14.1%	14.6%	18.3%	22.3%	26.2%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-12. Projected Demand-Side Resource Peak Load Impact in Delaware through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

A.5 The District of Columbia

Table A-13. Projected Demand-Side Resource Capacity in the District of Columbia through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	1	1	1	1	1	1	2
Demand Response (conventional)	25	32	43	43	30	29	28
Demand Response (smart grid-enabled)*	0	0	0	0	15	19	23
Energy Storage	0	0	0	0	7	16	26
DG-Fossil	292	286	280	274	254	238	225
DG-Renewables	19	28	37	47	106	173	245
Smart Grid (CVR)	0	0	0	0	3	7	11
TOTAL	338	347	360	364	417	482	560

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-13. Projected Demand-Side Resource Capacity in the District of Columbia through 2030

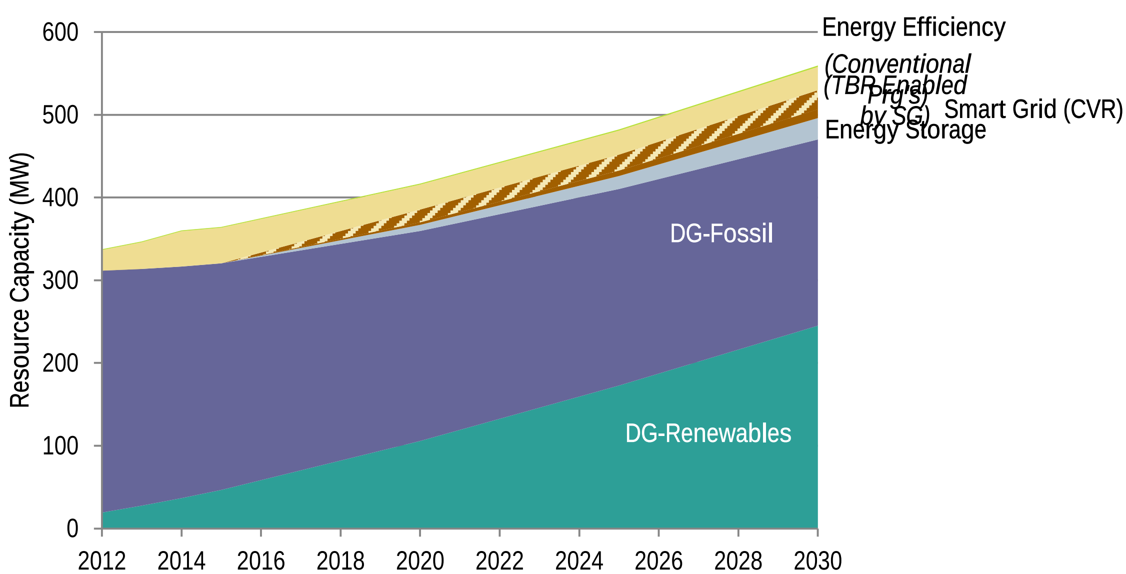


Table A-14. Projected Demand-Side Resource Annual Energy Impact in the District of Columbia through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	7	7	7	7	9	10	12
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	273	267	261	256	246	240	240
DG-Renewables	25	35	47	60	136	222	315
Smart Grid [a c]	0	0	0	0	2	4	6
TOTAL	304	309	315	323	392	477	572
Total Annual Electricity Consumption (AEC) [d]	11,578	11,434	11,578	11,291	12,567	13,173	13,476
% of AEC Supported by Demand-Side Resources	2.6%	2.7%	2.7%	2.9%	3.1%	3.6%	4.2%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-14. Projected Demand-Side Resource Annual Energy Impact in the District of Columbia through 2030

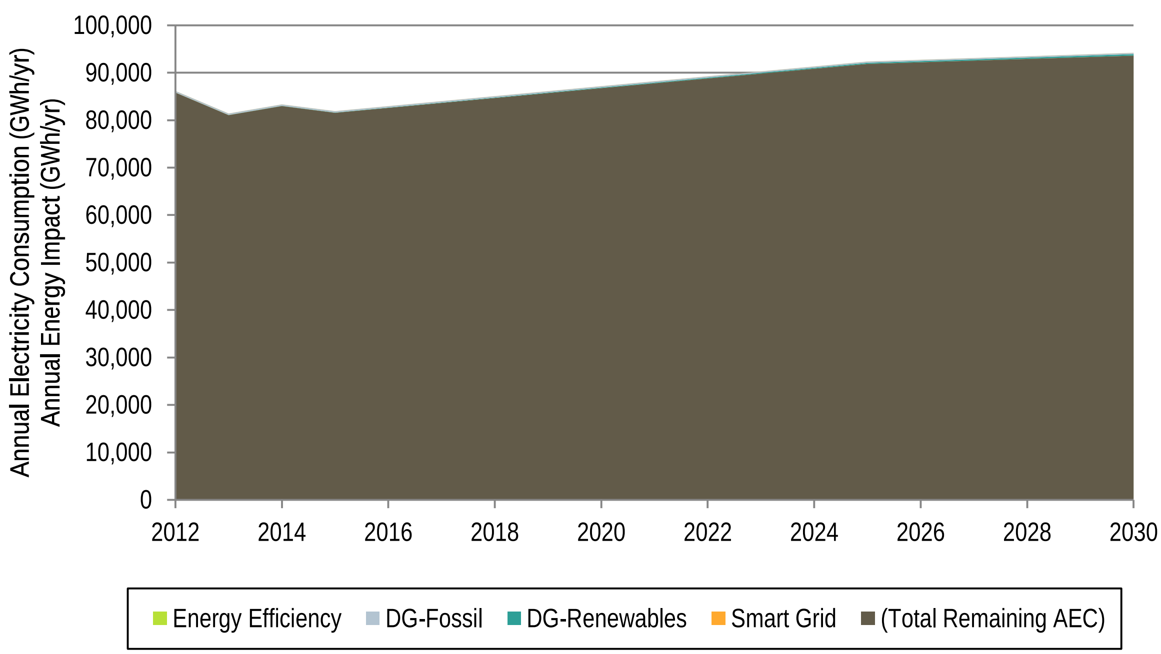
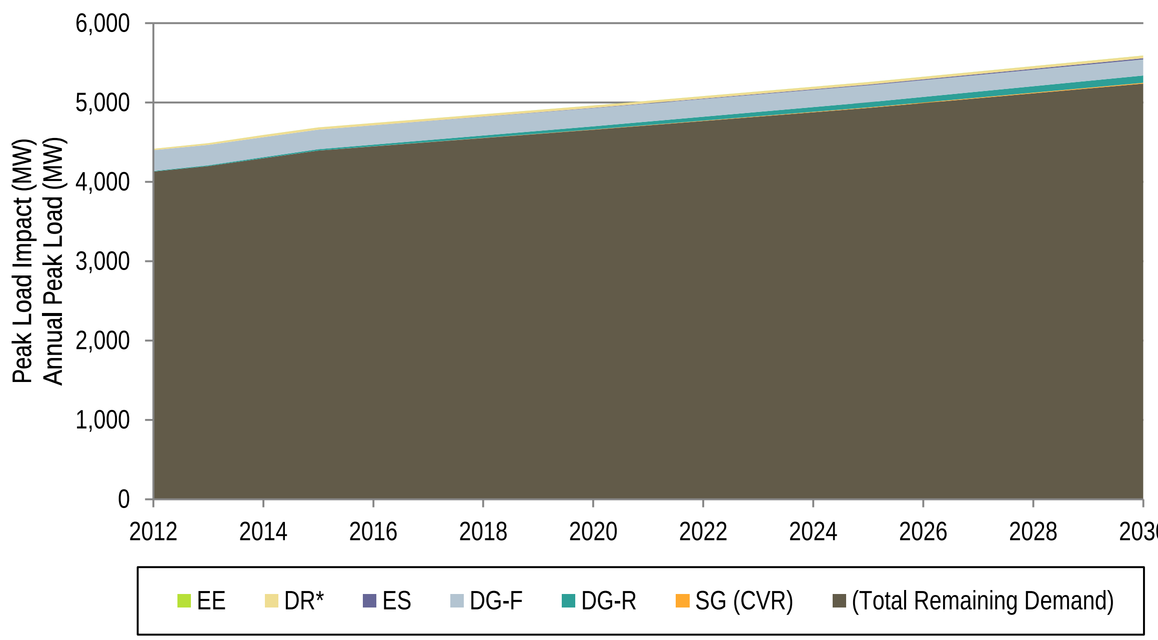


Table A-15. Projected Demand-Side Resource Peak Load Impact in the District of Columbia through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	1	1	1	1	1	1	2
Demand Response (conventional)	16	20	27	27	22	22	22
Demand Response (smart grid-enabled)*	0	0	0	0	7	9	10
Energy Storage	0	0	0	0	4	9	15
DG-Fossil	263	257	252	246	228	214	203
DG-Renewables	7	10	14	17	40	65	92
Smart Grid (CVR)	0	0	0	0	3	7	11
TOTAL	287	289	294	292	305	326	354
Total Annual Peak Load	4,416	4,487	4,590	4,686	4,962	5,258	5,592
% of Peak Load Supported by Demand-Side Resources	6.5%	6.4%	6.4%	6.2%	6.2%	6.2%	6.3%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-15. Projected Demand-Side Resource Peak Load Impact in the District of Columbia through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

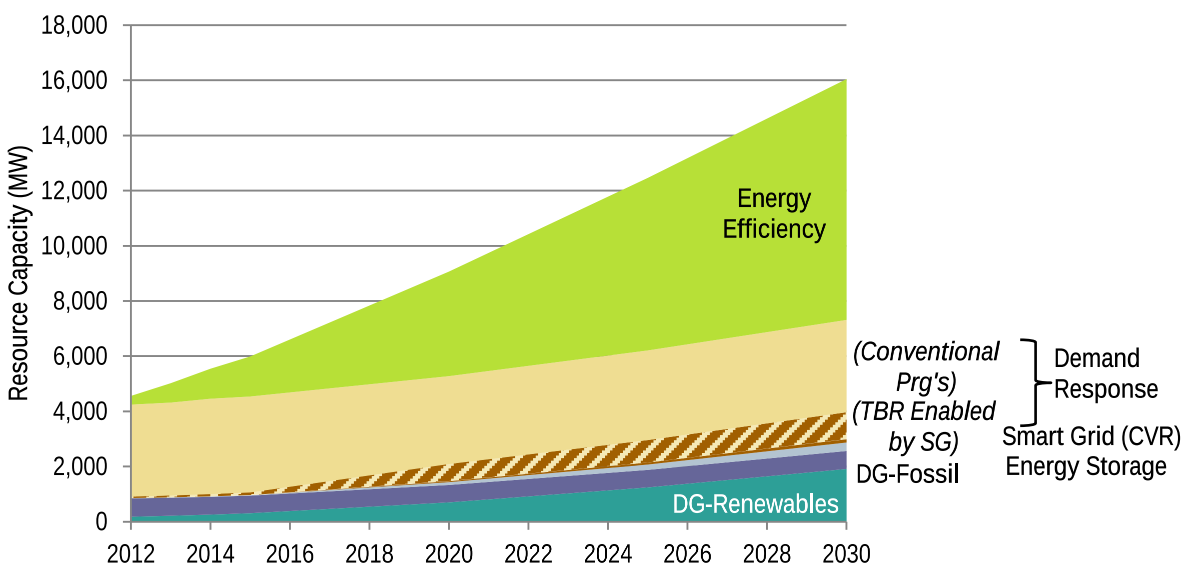
A.6 Florida[76]

Table A-16. Projected Demand-Side Resource Capacity in Florida through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	315	703	1,088	1,452	3,791	6,255	8,732
Demand Response (conventional)	3,334	3,370	3,459	3,479	3,187	3,251	3,348
Demand Response (smart grid-enabled)*	59	70	88	105	623	813	980
Energy Storage	10	10	10	10	101	194	307
DG-Fossil	663	654	645	637	631	635	651
DG-Renewables	179	214	255	307	699	1,242	1,911
Smart Grid (CVR)	0	0	0	0	34	73	117
TOTAL	4,559	5,020	5,545	5,989	9,067	12,463	16,046

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-16. Projected Demand-Side Resource Capacity in Florida through 2030



[76] Navigant used data from Seminole Electric Cooperative on behalf of its member distribution utilities.

Table A-17. Projected Demand-Side Resource Annual Energy Impact in Florida through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	908	2,027	3,137	4,186	10,933	18,038	25,181
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	1,091	1,089	1,087	1,086	1,139	1,212	1,308
DG-Renewables	740	809	879	967	1,559	2,376	3,396
Smart Grid [a c]	0	0	0	0	38	80	123
TOTAL	2,739	3,924	5,103	6,239	13,670	21,706	30,008
Total Annual Electricity Consumption (AEC) [d]	225,401	222,607	225,401	219,812	244,650	256,448	262,347
% of AEC Supported by Demand-Side Resources	1.2%	1.8%	2.3%	2.8%	5.6%	8.5%	11.4%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-17. Projected Demand-Side Resource Annual Energy Impact in Florida through 2030

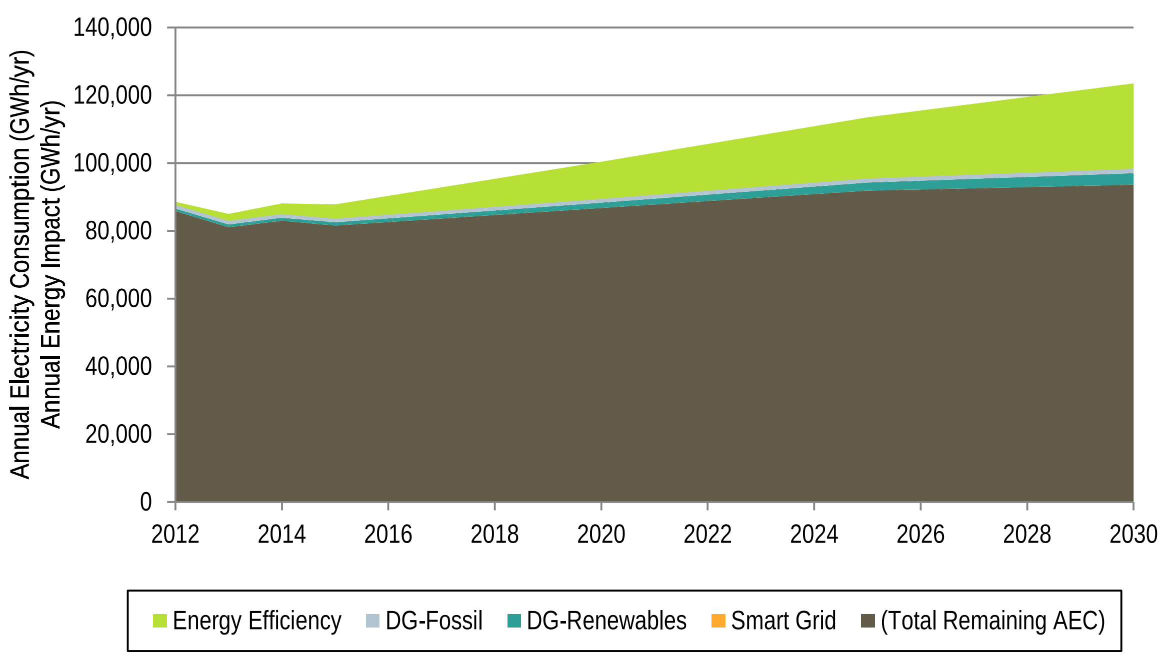
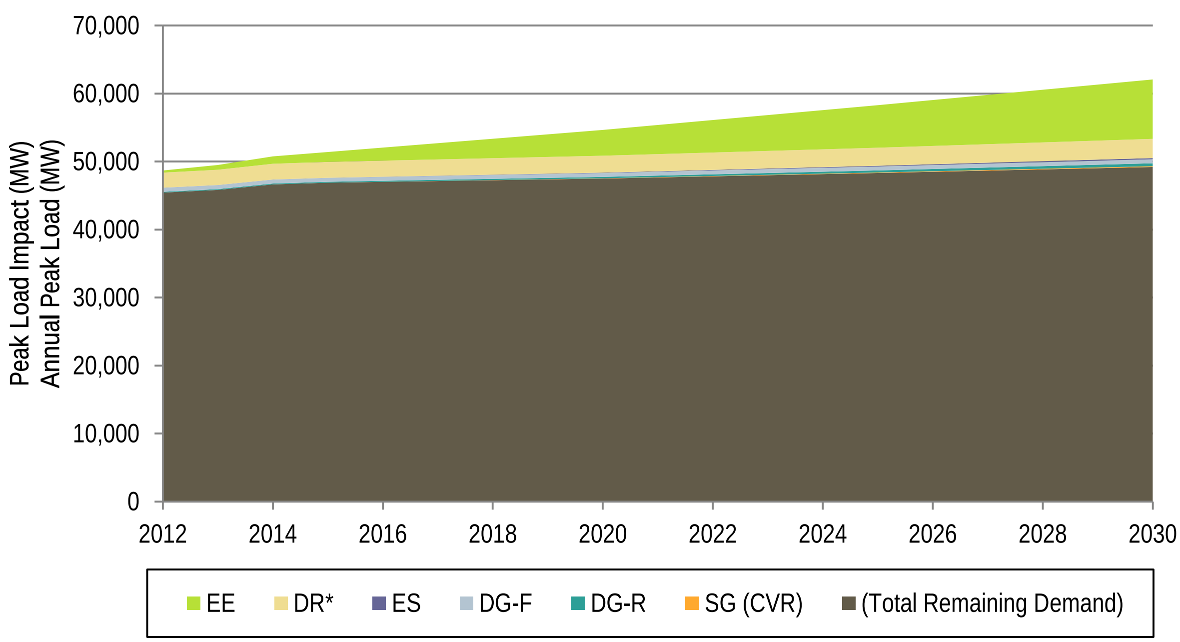


Table A-18. Projected Demand-Side Resource Peak Load Impact in Florida through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	315	703	1,088	1,452	3,791	6,255	8,732
Demand Response (conventional)	2,188	2,214	2,276	2,292	2,207	2,287	2,384
Demand Response (smart grid-enabled)*	27	31	40	47	280	366	441
Energy Storage	10	10	10	10	58	112	181
DG-Fossil	597	589	581	574	568	572	586
DG-Renewables	108	117	126	137	208	306	429
Smart Grid (CVR)	0	0	0	0	34	73	117
TOTAL	3,245	3,664	4,120	4,512	7,147	9,971	12,870
Total Annual Peak Load	48,677	49,488	50,754	51,395	54,643	58,282	62,064
% of Peak Load Supported by Demand-Side Resources	6.7%	7.4%	8.1%	8.8%	13.1%	17.1%	20.7%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-18. Projected Demand-Side Resource Peak Load Impact in Florida through 2030



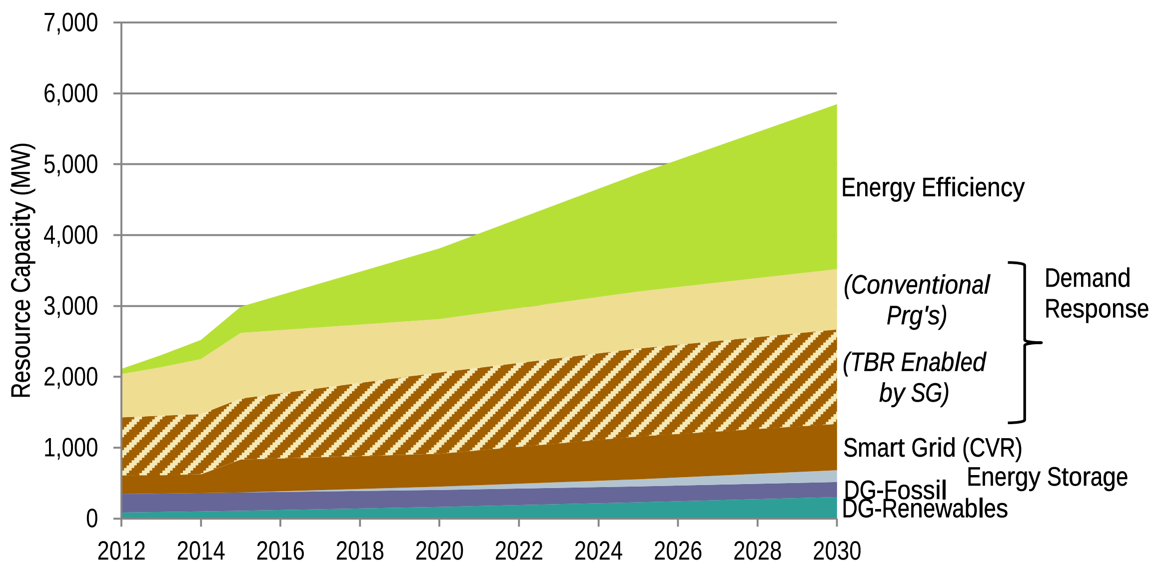
Note: "DR" include both the conventional and smart grid-enabled programs.

A.7 Georgia[77]

Table A-19. Projected Demand-Side Resource Capacity in Georgia through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	73	172	270	369	998	1,661	2,328
Demand Response (conventional)	612	683	775	927	753	804	852
Demand Response (smart grid-enabled)*	817	836	852	860	1,148	1,240	1,332
Energy Storage	0	0	0	0	47	100	167
DG-Fossil	261	260	259	258	240	224	212
DG-Renewables	85	92	100	110	164	229	303
Smart Grid (CVR)	264	264	264	464	464	606	653
TOTAL	2,112	2,307	2,521	2,989	3,812	4,864	5,847
** Includes time-based rate programs that require AMI meters with two-way communication capability.*							

Figure A-19. Projected Demand-Side Resource Capacity in Georgia through 2030



[77] Navigant compiled data pertaining Georgia electric cooperative utilities by aggregating data from electric cooperative association instead of collecting data from individual cooperatives.

Table A-20. Projected Demand-Side Resource Annual Energy Impact in Georgia through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	247	581	916	1,250	3,378	5,623	7,882
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	516	520	524	528	517	513	517
DG-Renewables	417	435	451	470	564	681	822
Smart Grid [a c]	55	55	55	97	97	259	318
TOTAL	1,236	1,592	1,946	2,345	4,556	7,076	9,539
Total Annual Electricity Consumption (AEC) [d]	136,559	134,866	136,559	133,173	148,221	155,369	158,943
% of AEC Supported by Demand-Side Resources	0.9%	1.2%	1.4%	1.8%	3.1%	4.6%	6.0%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-20. Projected Demand-Side Resource Annual Energy Impact in Georgia through 2030

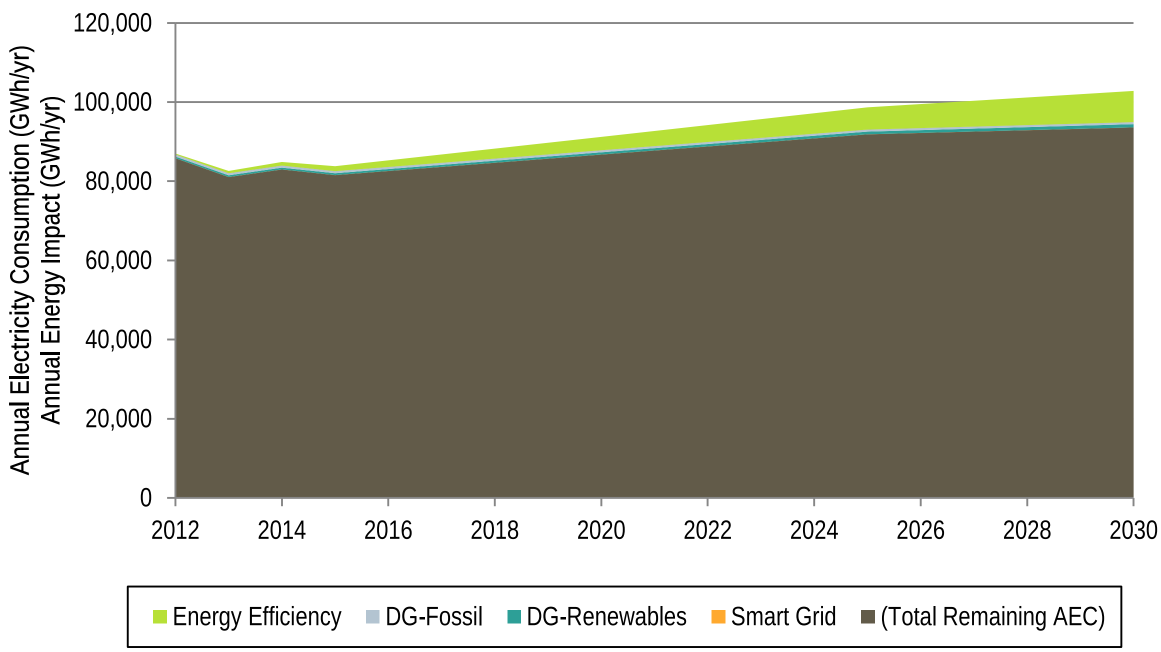
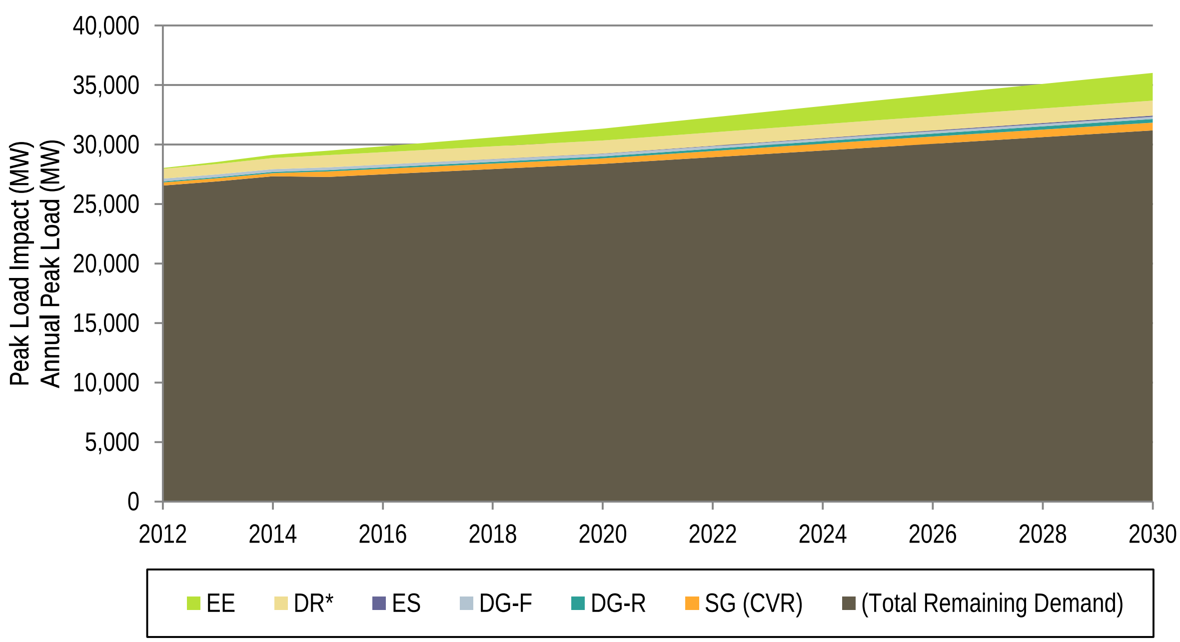


Table A-21. Projected Demand-Side Resource Peak Load Impact in Georgia through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	73	172	270	369	998	1,661	2,328
Demand Response (conventional)	455	498	553	642	577	618	657
Demand Response (smart grid-enabled)*	368	376	383	387	517	558	600
Energy Storage	0	0	0	0	27	59	99
DG-Fossil	235	234	233	233	216	202	191
DG-Renewables	85	92	100	110	164	229	303
Smart Grid (CVR)	264	264	264	464	464	606	653
TOTAL	1,479	1,636	1,804	2,204	2,962	3,932	4,831
Total Annual Peak Load	28,028	28,542	29,133	29,478	31,335	33,706	36,016
% of Peak Load Supported by Demand-Side Resources	5.3%	5.7%	6.2%	7.5%	9.5%	11.7%	13.4%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-21. Projected Demand-Side Resource Peak Load Impact in Georgia through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

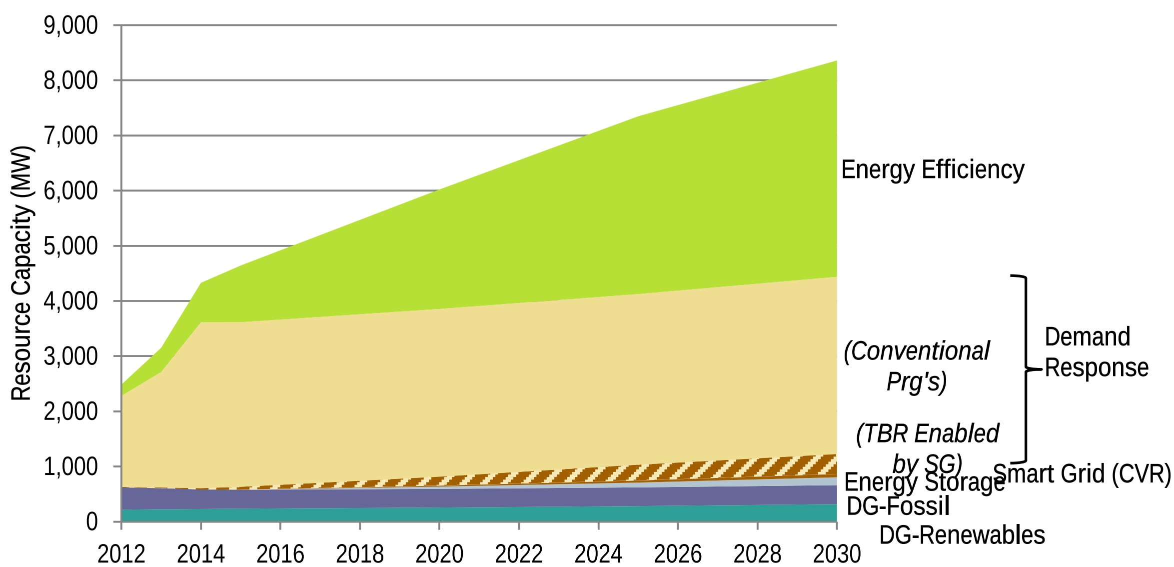
A.8 Illinois[78]

Table A-22. Projected Demand-Side Resource Capacity in Illinois through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	205	440	715	1,028	2,166	3,223	3,922
Demand Response (conventional)	1,651	2,095	3,009	2,984	3,041	3,094	3,214
Demand Response (smart grid-enabled)*	9	13	17	54	162	287	361
Energy Storage	0	0	0	0	41	87	143
DG-Fossil	402	381	359	342	338	339	344
DG-Renewables	218	225	230	236	256	282	317
Smart Grid (CVR)	0	0	0	0	17	37	59
TOTAL	2,485	3,153	4,330	4,643	6,022	7,349	8,361

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-22. Projected Demand-Side Resource Capacity in Illinois through 2030



78 EE forecast for Commonwealth Edison service territory is based on the IL Public Utilities Act goals.

Table A-23. Projected Demand-Side Resource Annual Energy Impact in Illinois through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	940	2,016	3,280	4,715	9,936	14,784	17,990
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	858	776	694	633	617	610	611
DG-Renewables	1,181	1,222	1,252	1,286	1,398	1,549	1,759
Smart Grid [a c]	0	0	0	0	19	41	65
TOTAL	2,978	4,014	5,225	6,635	11,970	16,984	20,426
Total Annual Electricity Consumption (AEC) [d]	124,897	128,372	117,538	125,102	124,488	133,687	138,388
% of AEC Supported by Demand-Side Resources	2.4%	3.1%	4.4%	5.3%	9.6%	12.7%	14.8%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-23. Projected Demand-Side Resource Annual Energy Impact in Illinois through 2030

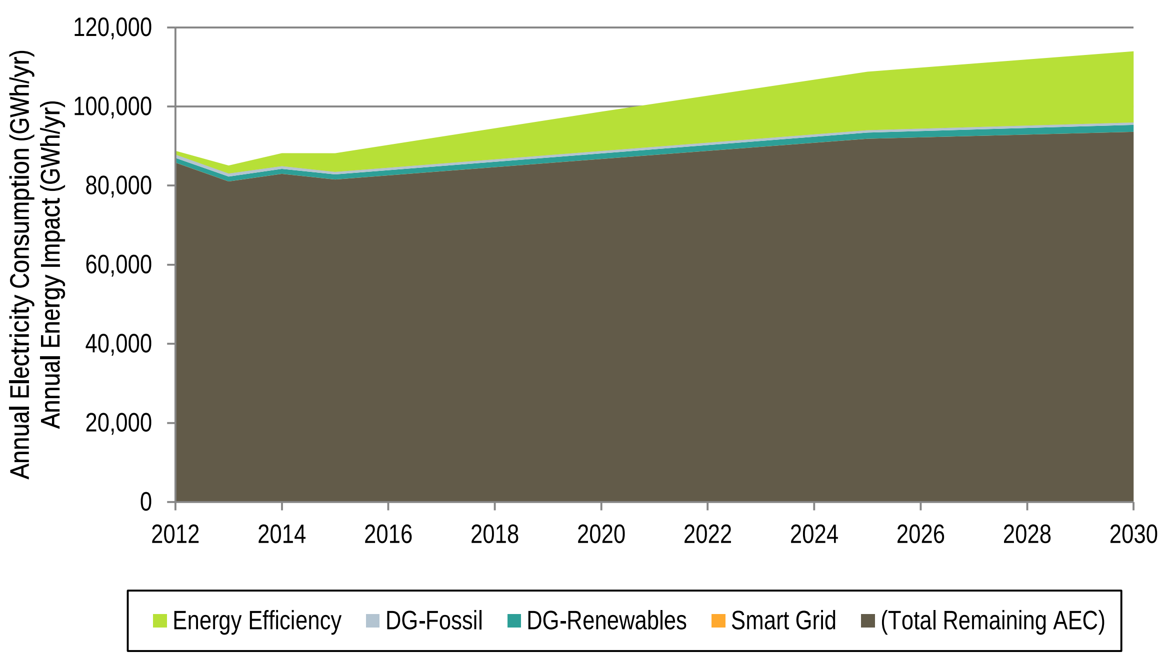
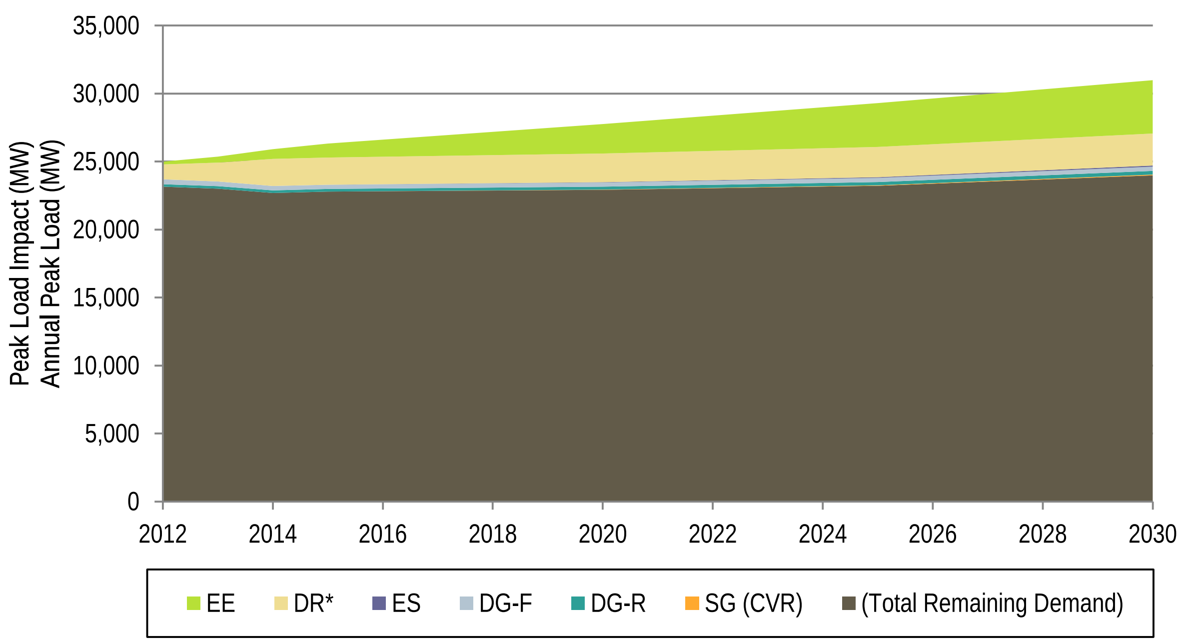


Table A-24. Projected Demand-Side Resource Peak Load Impact in Illinois through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	205	440	715	1,028	2,166	3,223	3,922
Demand Response (conventional)	1,089	1,382	1,984	1,975	2,036	2,096	2,191
Demand Response (smart grid-enabled)*	4	6	7	24	73	129	163
Energy Storage	0	0	0	0	24	51	85
DG-Fossil	362	343	323	308	304	305	310
DG-Renewables	181	187	192	197	215	238	270
Smart Grid (CVR)	0	0	0	0	17	37	59
TOTAL	1,841	2,357	3,222	3,532	4,835	6,080	6,999
Total Annual Peak Load	24,990	25,358	25,907	26,319	27,754	29,294	30,980
% of Peak Load Supported by Demand-Side Resources	7.4%	9.3%	12.4%	13.4%	17.4%	20.8%	22.6%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-24. Projected Demand-Side Resource Peak Load Impact in Illinois through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

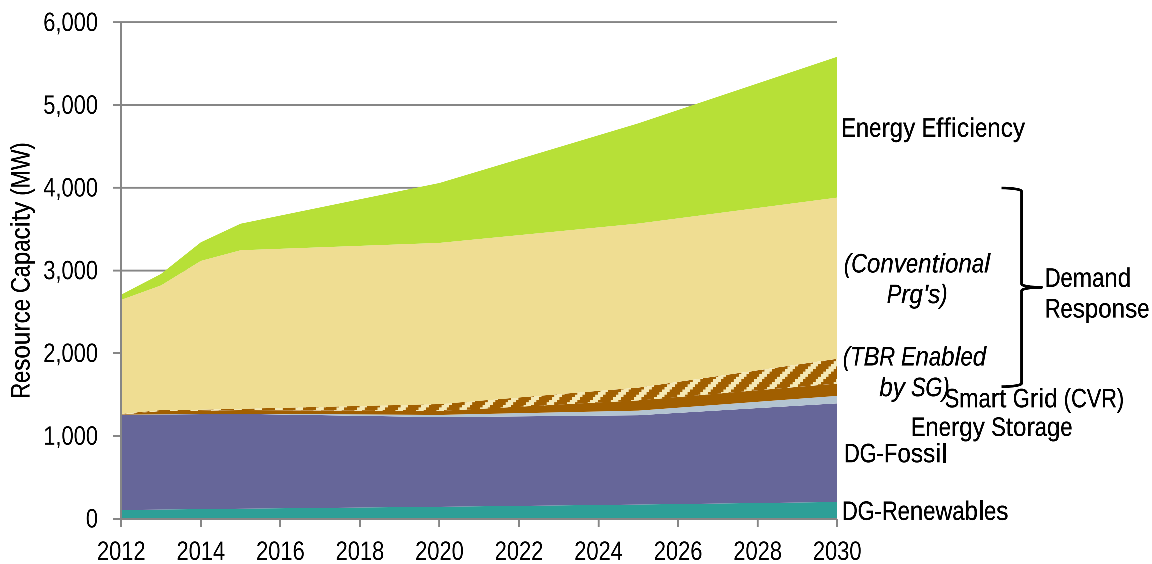
A.9 Indiana[79]

Table A-25. Projected Demand-Side Resource Capacity in Indiana through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	63	138	224	320	723	1,210	1,701
Demand Response (conventional)	1,378	1,508	1,798	1,918	1,950	1,984	1,949
Demand Response (smart grid-enabled)*	10	11	12	16	82	154	301
Energy Storage	2	2	2	2	28	57	91
DG-Fossil	1,150	1,148	1,147	1,145	1,083	1,079	1,192
DG-Renewables	106	111	116	122	145	172	202
Smart Grid (CVR)	0	40	41	43	47	123	148
TOTAL	2,709	2,959	3,341	3,566	4,057	4,778	5,583

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-25. Projected Demand-Side Resource Capacity in Indiana through 2030



[79] The forecast for Indiana assumes that the 2012 EE data available for Indiana Power & Light are cumulative. Navigant used 2011 EIA-861 data to estimate the incremental annual savings achieved in 2012.

Table A-26. Projected Demand-Side Resource Annual Energy Impact in Indiana through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	490	1,085	1,757	2,508	5,664	9,480	13,323
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	2,337	2,340	2,344	2,349	1,978	1,737	1,878
DG-Renewables	533	553	568	586	649	730	834
Smart Grid [a c]	0	0	4	11	36	138	179
TOTAL	3,360	3,977	4,674	5,453	8,326	12,084	16,214
Total Annual Electricity Consumption (AEC) [d]	92,496	95,070	87,046	92,648	92,193	99,006	102,488
% of AEC Supported by Demand-Side Resources	3.6%	4.2%	5.4%	5.9%	9.0%	12.2%	15.8%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-26. Projected Demand-Side Resource Annual Energy Impact in Indiana through 2030

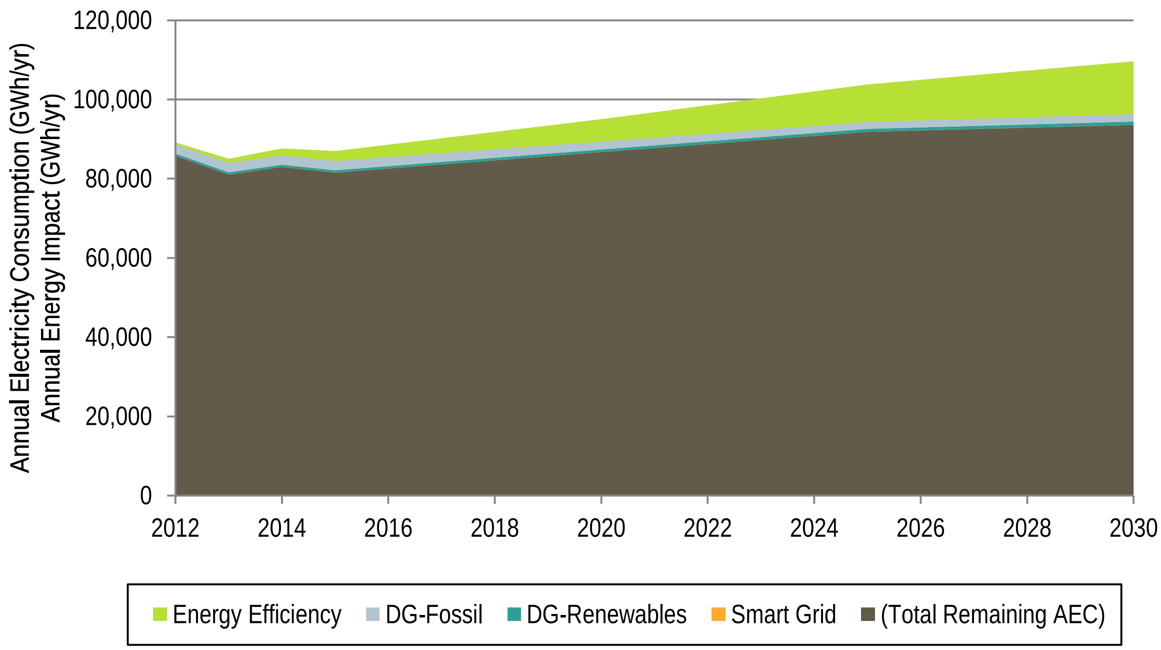
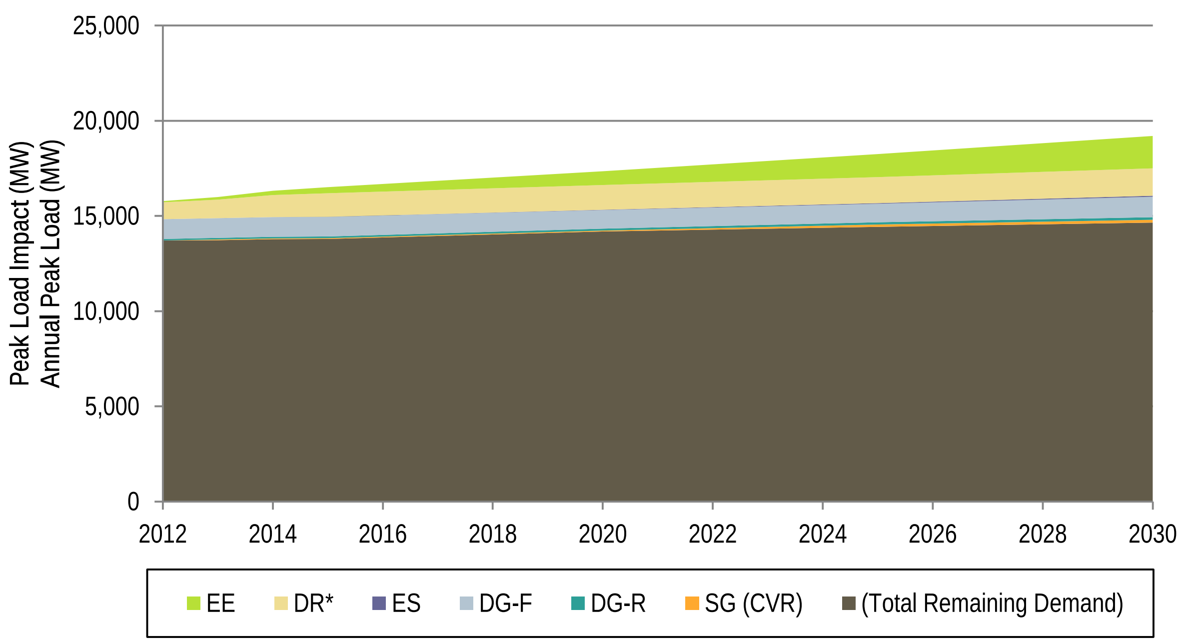


Table A-27. Projected Demand-Side Resource Peak Load Impact in Indiana through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	63	138	224	320	723	1,210	1,701
Demand Response (conventional)	883	966	1,152	1,229	1,262	1,297	1,303
Demand Response (smart grid-enabled)*	4	5	6	7	37	69	135
Energy Storage	2	2	2	2	17	34	55
DG-Fossil	1,035	1,033	1,032	1,031	974	971	1,073
DG-Renewables	80	84	86	90	102	118	136
Smart Grid (CVR)	0	40	41	43	47	123	148
TOTAL	2,067	2,269	2,543	2,722	3,163	3,823	4,550
Total Annual Peak Load	15,778	15,992	16,320	16,510	17,345	18,248	19,199
% of Peak Load Supported by Demand-Side Resources	13.1%	14.2%	15.6%	16.5%	18.2%	20.9%	23.7%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-27. Projected Demand-Side Resource Peak Load Impact in Indiana through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

A.10 Iowa

Table A-28. Projected Demand-Side Resource Capacity in Iowa through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	120	190	297	406	1,046	1,711	2,400
Demand Response (conventional)	728	1,044	1,165	1,229	1,278	1,327	1,373
Demand Response (smart grid-enabled)*	0	0	0	1	9	24	42
Energy Storage	0	0	0	0	12	24	39
DG-Fossil	1,076	1,076	1,056	1,037	1,062	1,087	1,112
DG-Renewables	103	104	106	107	110	116	123
Smart Grid (CVR)	0	0	0	0	5	10	16
TOTAL	2,027	2,414	2,625	2,779	3,522	4,298	5,106

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-28. Projected Demand-Side Resource Capacity in Iowa through 2030

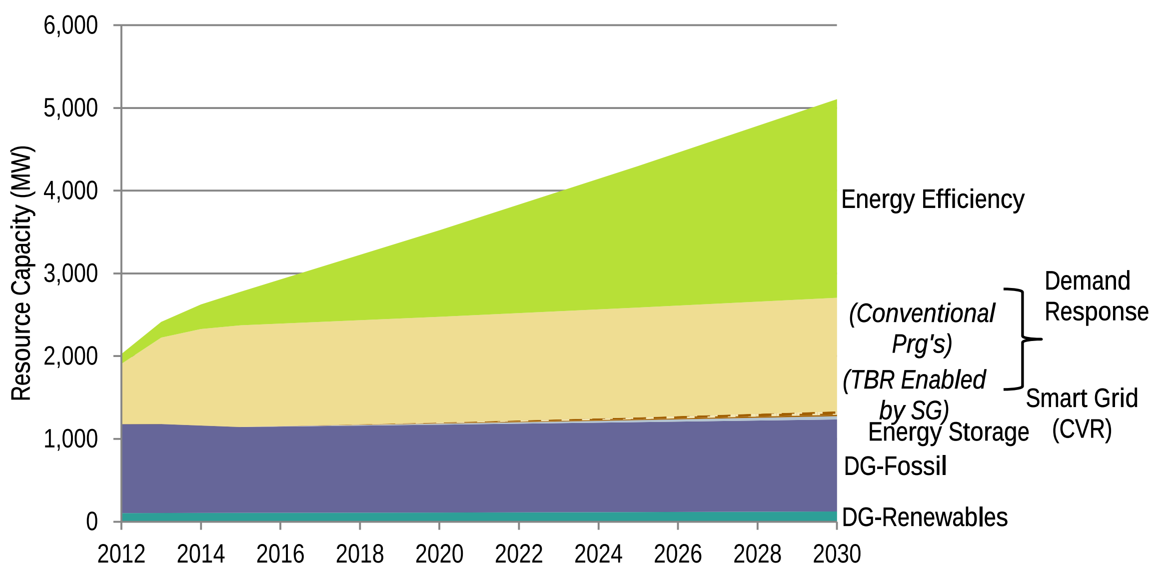


Table A-29. Projected Demand-Side Resource Annual Energy Impact in Iowa through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	695	1,102	1,723	2,352	6,064	9,915	13,912
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	2,014	1,991	1,943	1,896	1,880	1,868	1,860
DG-Renewables	352	357	363	367	383	408	441
Smart Grid [a c]	0	0	0	0	8	16	24
TOTAL	3,060	3,450	4,029	4,615	8,334	12,206	16,236
Total Annual Electricity Consumption (AEC) [d]	49,156	48,736	50,556	48,036	49,156	50,136	51,117
% of AEC Supported by Demand-Side Resources	6.2%	7.1%	8.0%	9.6%	17.0%	24.3%	31.8%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-29. Projected Demand-Side Resource Annual Energy Impact in Iowa through 2030

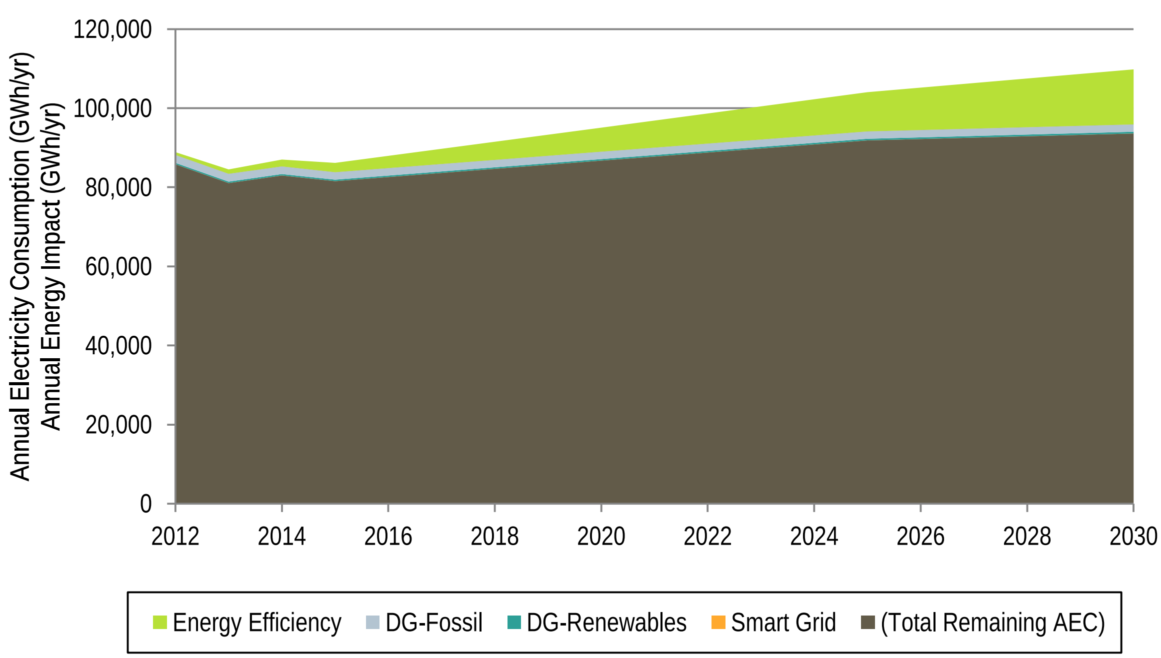
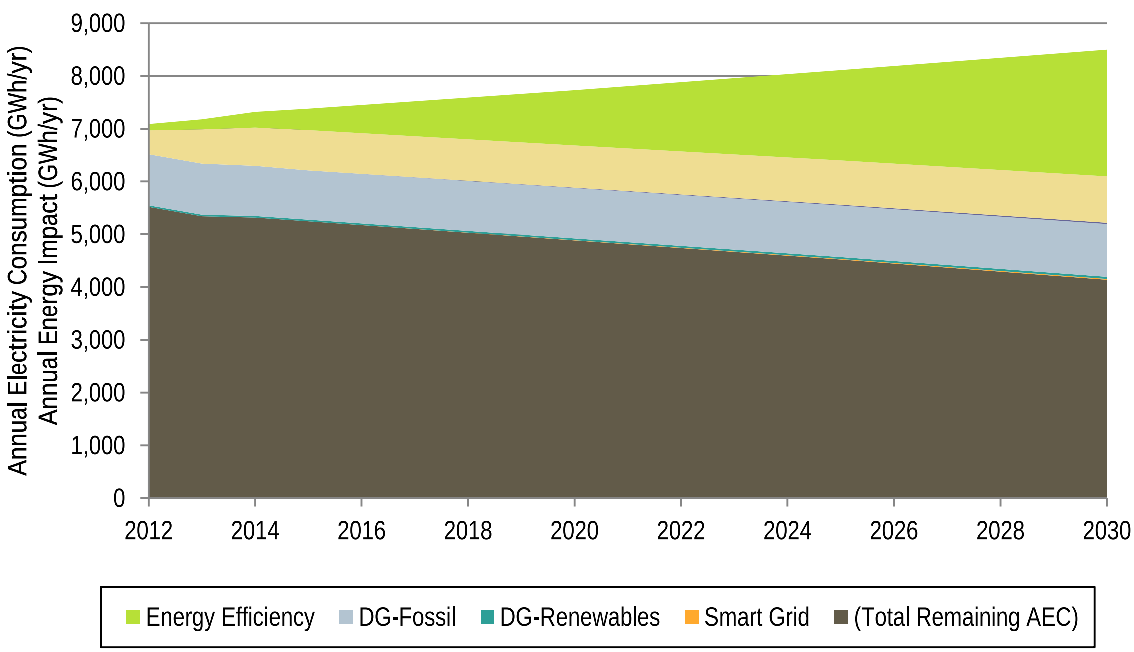


Table A-30. Projected Demand-Side Resource Peak Load Impact in Iowa through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	120	190	297	406	1,046	1,711	2,400
Demand Response (conventional)	453	649	725	764	797	830	861
Demand Response (smart grid-enabled)*	0	0	0	0	4	11	19
Energy Storage	0	0	0	0	7	14	23
DG-Fossil	968	968	951	933	956	978	1,001
DG-Renewables	29	30	30	31	33	36	40
Smart Grid (CVR)	0	0	0	0	5	10	16
TOTAL	1,570	1,837	2,003	2,135	2,848	3,589	4,361
Total Annual Peak Load	7,089	7,179	7,320	7,381	7,731	8,111	8,499
% of Peak Load Supported by Demand-Side Resources	22.1%	25.6%	27.4%	28.9%	36.8%	44.3%	51.3%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-30. Projected Demand-Side Resource Peak Load Impact in Iowa through 2030



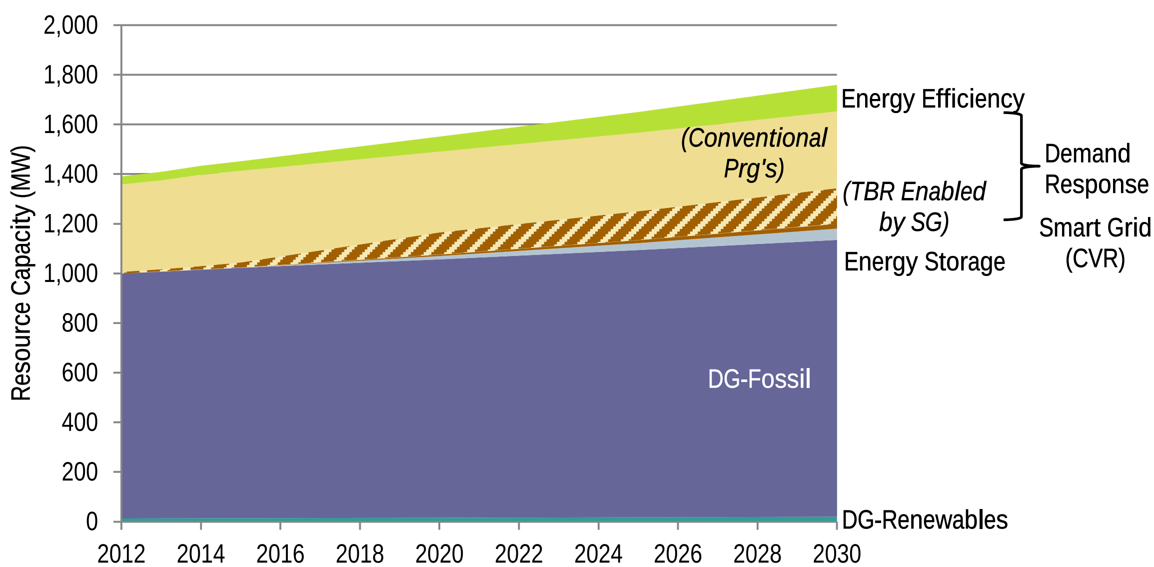
A.11 Kansas[80]

Table A-31. Projected Demand-Side Resource Capacity in Kansas through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	33	34	36	39	61	84	107
Demand Response (conventional)	352	358	368	369	326	316	310
Demand Response (smart grid-enabled)*	6	9	14	21	89	116	144
Energy Storage	0	0	0	0	13	28	46
DG-Fossil	987	994	1,001	1,009	1,041	1,077	1,115
DG-Renewables	13	13	14	14	16	17	20
Smart Grid (CVR)	0	0	0	0	6	12	19
TOTAL	1,391	1,409	1,434	1,452	1,551	1,650	1,760

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-31. Projected Demand-Side Resource Capacity in Kansas through 2030



[80] The forecast for Kansas assumes that the 2012 EE data available for Empire District Electric Company and Kansas City Power and Light Company are cumulative. Navigant used 2011 EIA-861 data to estimate the incremental annual savings achieved in 2012.

Table A-32. Projected Demand-Side Resource Annual Energy Impact in Kansas through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	58	61	65	69	108	149	191
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	1,768	1,794	1,821	1,848	1,946	2,050	2,161
DG-Renewables	66	68	70	72	78	87	98
Smart Grid [a c]	0	0	0	0	7	14	21
TOTAL	1,892	1,924	1,956	1,989	2,139	2,299	2,471
Total Annual Electricity Consumption (AEC) [d]	43,861	43,486	45,110	42,861	43,861	44,735	45,610
% of AEC Supported by Demand-Side Resources	4.3%	4.4%	4.3%	4.6%	4.9%	5.1%	5.4%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-32. Projected Demand-Side Resource Annual Energy Impact in Kansas through 2030

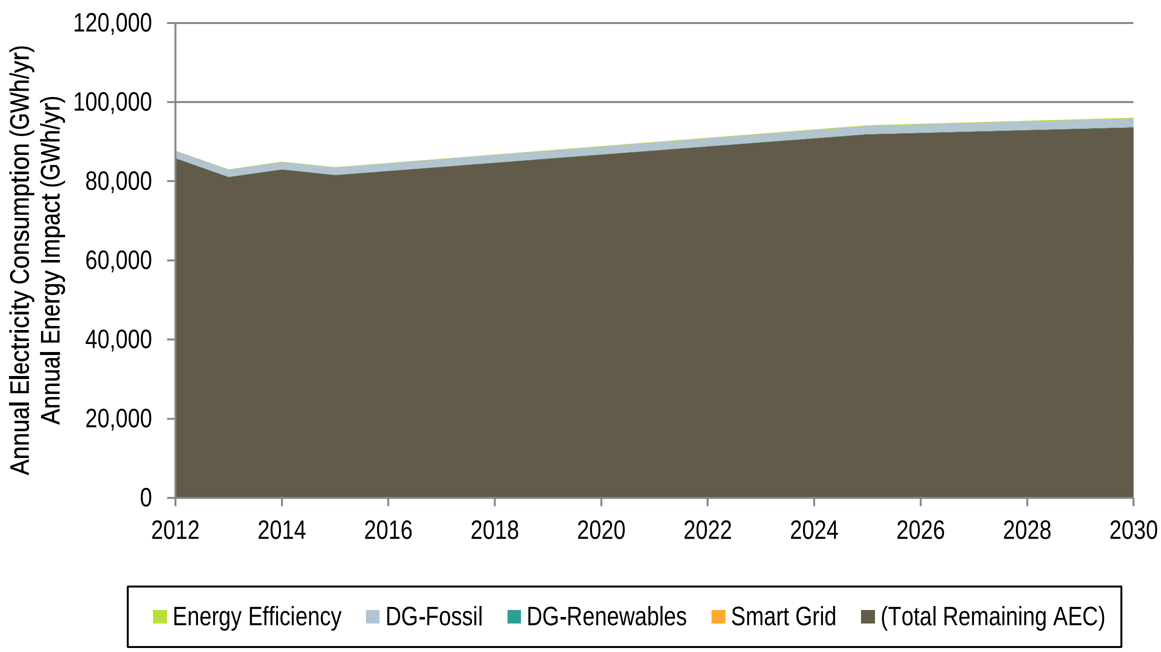
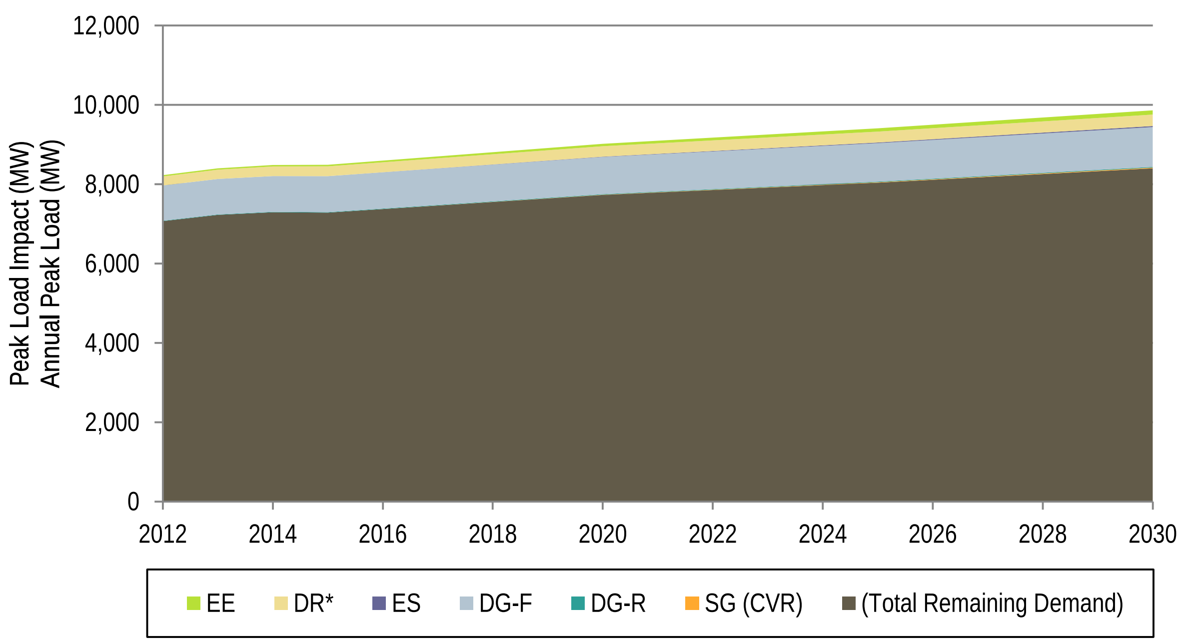


Table A-33. Projected Demand-Side Resource Peak Load Impact in Kansas through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	33	34	36	39	61	84	107
Demand Response (conventional)	225	229	236	238	223	222	223
Demand Response (smart grid-enabled)*	3	4	6	10	40	52	65
Energy Storage	0	0	0	0	8	16	27
DG-Fossil	888	895	901	908	937	969	1,004
DG-Renewables	10	11	11	12	13	15	17
Smart Grid (CVR)	0	0	0	0	6	12	19
TOTAL	1,159	1,173	1,192	1,206	1,288	1,371	1,462
Total Annual Peak Load	8,228	8,399	8,483	8,489	9,017	9,408	9,861
% of Peak Load Supported by Demand-Side Resources	14.1%	14.0%	14.0%	14.2%	14.3%	14.6%	14.8%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-33. Projected Demand-Side Resource Peak Load Impact in Kansas through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

A.12 Kentucky

Table A-34. Projected Demand-Side Resource Capacity in Kentucky through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	27	50	79	96	201	318	433
Demand Response (conventional)	555	584	674	686	660	615	551
Demand Response (smart grid-enabled)*	14	16	17	19	95	189	309
Energy Storage	0	0	0	0	23	49	81
DG-Fossil	51	47	43	39	34	30	27
DG-Renewables	32	36	40	44	64	86	109
Smart Grid (CVR)	0	0	4	6	9	78	101
TOTAL	679	733	857	890	1,085	1,364	1,610

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-34. Projected Demand-Side Resource Capacity in Kentucky through 2030

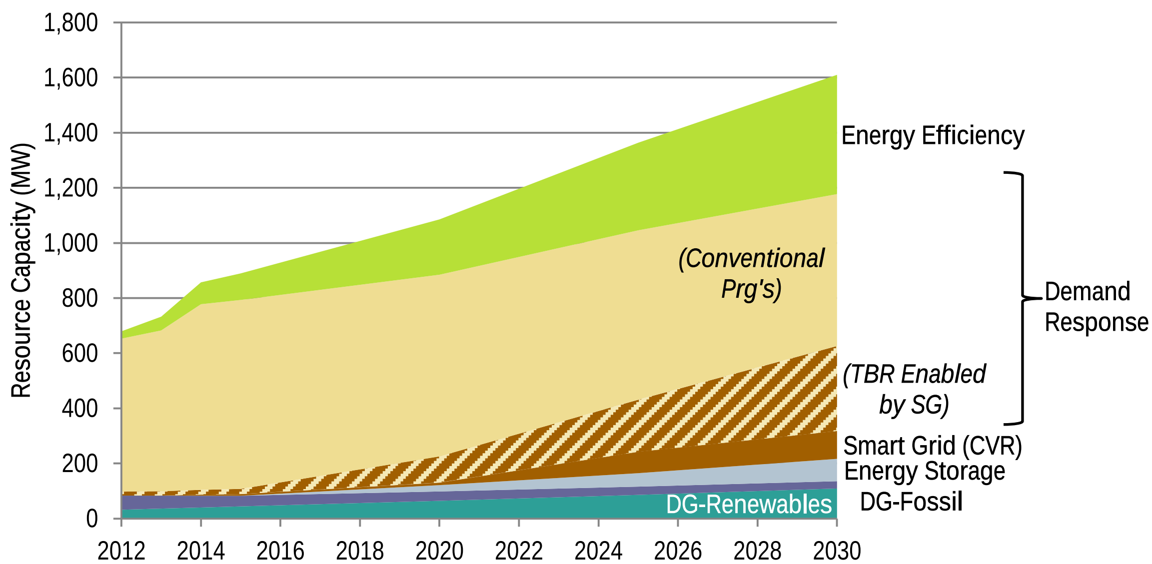


Table A-35. Projected Demand-Side Resource Annual Energy Impact in Kentucky through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	224	423	671	815	1,697	2,688	3,659
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	120	111	102	92	87	82	80
DG-Renewables	166	176	184	193	229	273	324
Smart Grid [a c]	0	0	18	30	44	144	180
TOTAL	511	709	975	1,130	2,057	3,186	4,244
Total Annual Electricity Consumption (AEC) [d]	87,739	83,014	85,039	83,689	89,538	95,388	97,862
% of AEC Supported by Demand-Side Resources	0.6%	0.9%	1.1%	1.4%	2.3%	3.3%	4.3%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-35. Projected Demand-Side Resource Annual Energy Impact in Kentucky through 2030

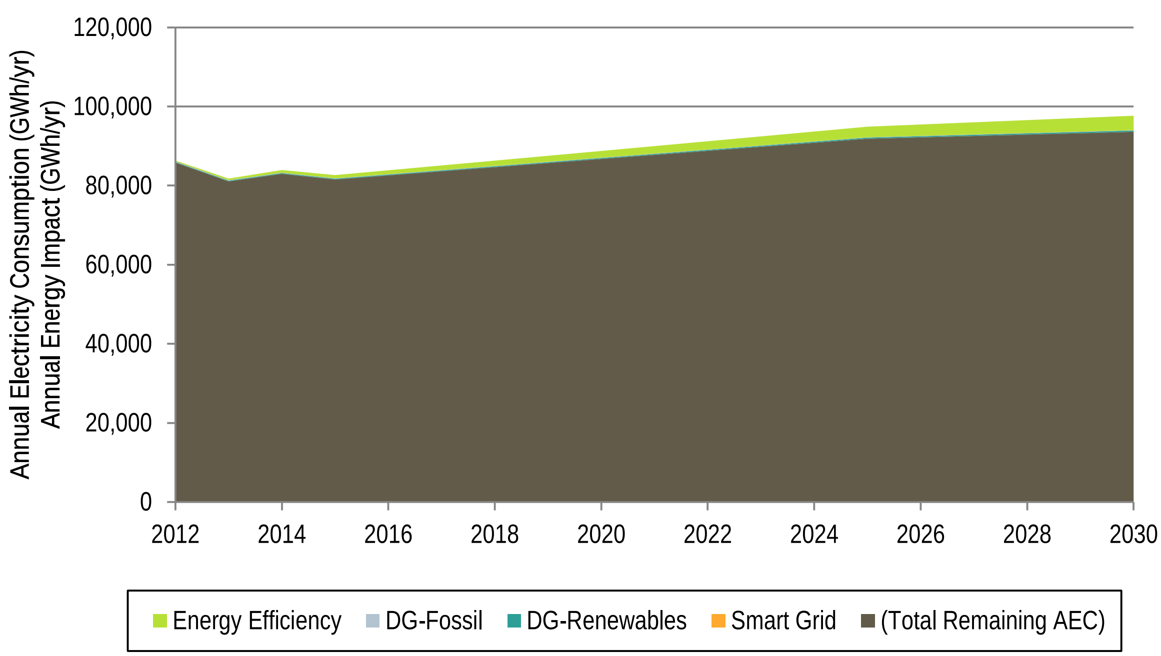
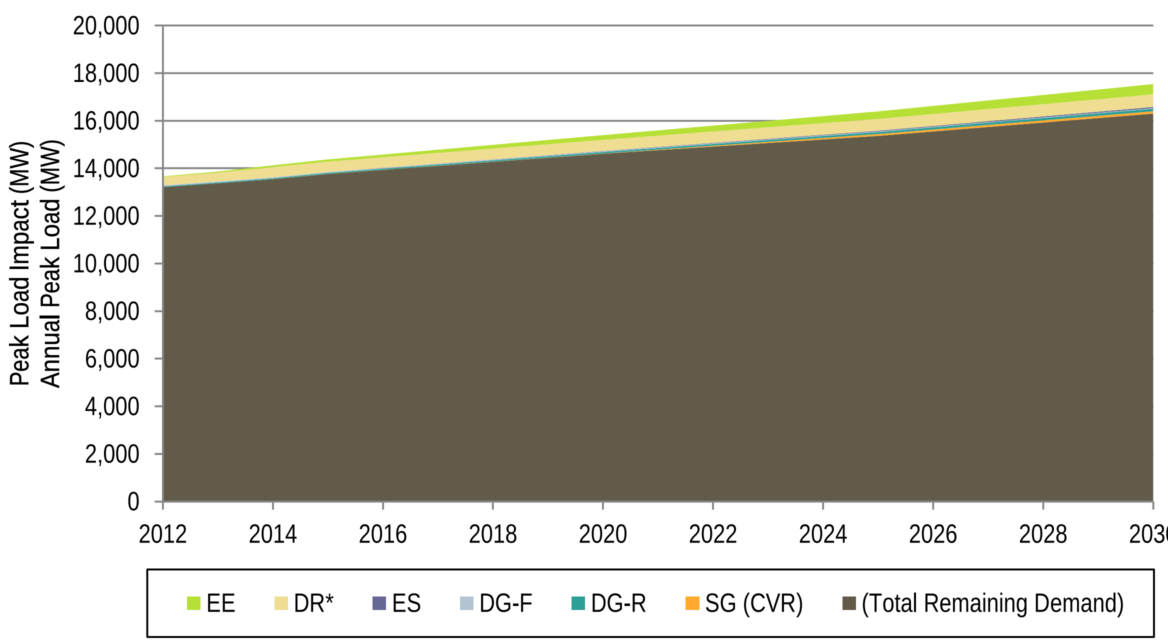


Table A-36. Projected Demand-Side Resource Peak Load Impact in Kentucky through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	27	50	79	96	201	318	433
Demand Response (conventional)	343	361	417	424	421	409	389
Demand Response (smart grid-enabled)*	7	7	8	9	43	85	139
Energy Storage	0	0	0	0	13	29	48
DG-Fossil	46	42	39	35	31	27	24
DG-Renewables	32	36	40	44	64	86	109
Smart Grid (CVR)	0	0	4	6	9	78	101
TOTAL	455	497	586	614	782	1,031	1,243
Total Annual Peak Load	13,663	13,866	14,127	14,375	15,395	16,392	17,539
% of Peak Load Supported by Demand-Side Resources	3.3%	3.6%	4.2%	4.3%	5.1%	6.3%	7.1%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-36. Projected Demand-Side Resource Peak Load Impact in Kentucky through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

A.13 Louisiana

Table A-37. Projected Demand-Side Resource Capacity in Louisiana through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	12	25	38	53	130	214	297
Demand Response (conventional)	283	292	317	342	291	250	141
Demand Response (smart grid-enabled)*	16	32	35	40	114	176	310
Energy Storage	0	0	0	0	30	63	104
DG-Fossil	483	493	504	515	604	709	844
DG-Renewables	38	55	73	94	225	378	549
Smart Grid (CVR)	0	0	0	0	13	27	43
TOTAL	832	898	967	1,044	1,406	1,818	2,287

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-37. Projected Demand-Side Resource Capacity in Louisiana through 2030

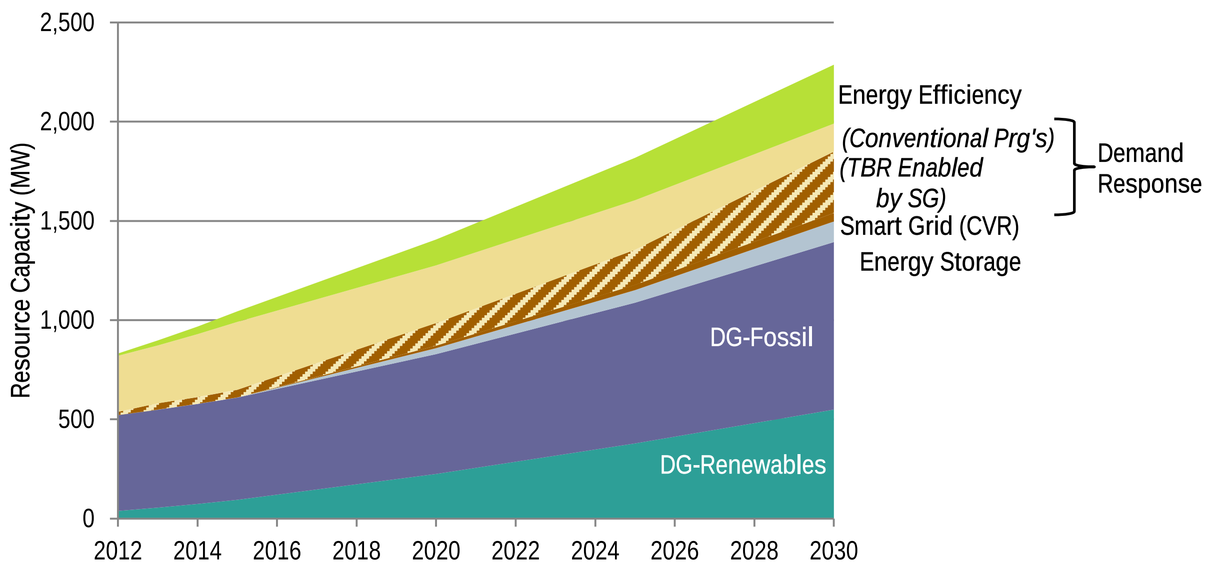


Table A-38. Projected Demand-Side Resource Annual Energy Impact in Louisiana through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	105	230	346	484	1,183	1,939	2,693
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	1,519	1,558	1,598	1,639	1,932	2,277	2,706
DG-Renewables	103	127	153	182	358	567	801
Smart Grid [a c]	0	0	0	0	14	28	43
TOTAL	1,727	1,914	2,096	2,305	3,487	4,812	6,243
Total Annual Electricity Consumption (AEC) [d]	85,517	82,392	83,528	84,522	86,795	90,062	91,483
% of AEC Supported by Demand-Side Resources	2.0%	2.3%	2.5%	2.7%	4.0%	5.3%	6.8%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-38. Projected Demand-Side Resource Annual Energy Impact in Louisiana through 2030

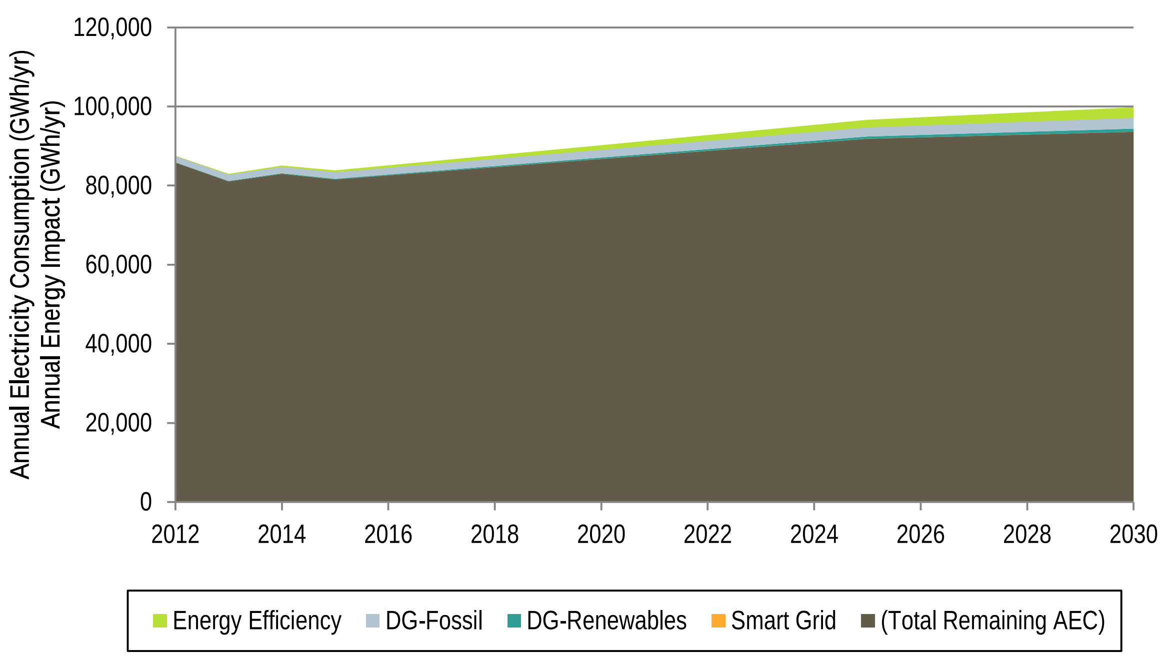
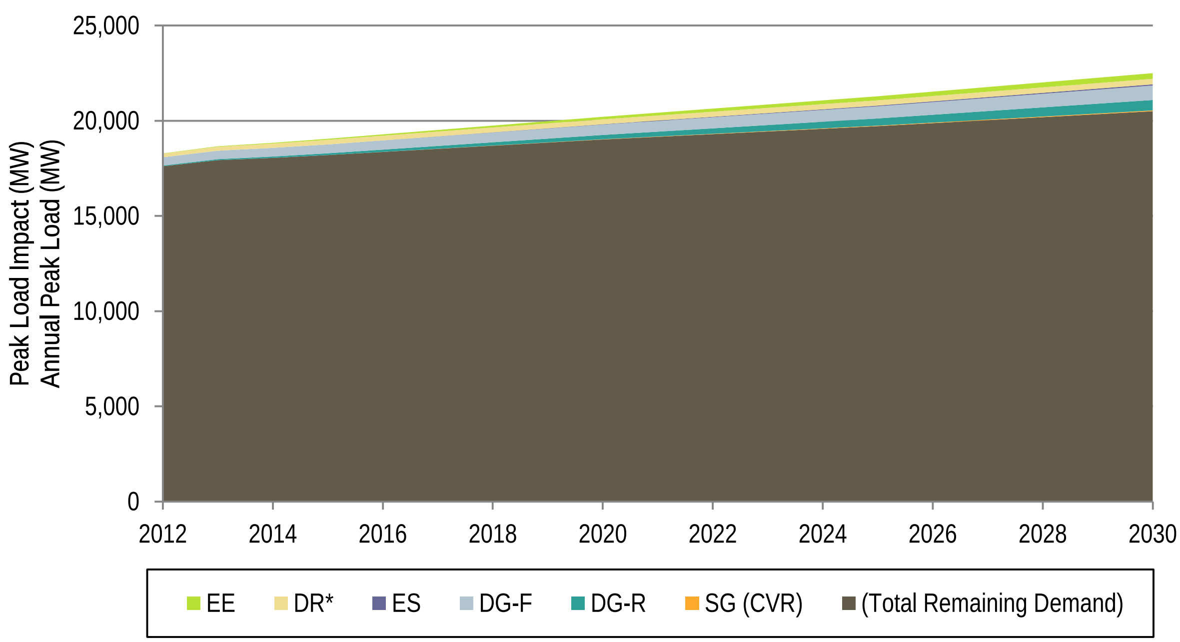


Table A-39. Projected Demand-Side Resource Peak Load Impact in Louisiana through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	12	25	38	53	130	214	297
Demand Response (conventional)	186	195	211	228	210	196	151
Demand Response (smart grid-enabled)*	7	15	16	18	51	79	139
Energy Storage	0	0	0	0	18	37	62
DG-Fossil	435	444	454	464	544	638	760
DG-Renewables	38	55	73	94	225	378	549
Smart Grid (CVR)	0	0	0	0	13	27	43
TOTAL	677	733	792	857	1,190	1,570	2,001
Total Annual Peak Load	18,284	18,659	18,838	19,052	20,205	21,283	22,498
% of Peak Load Supported by Demand-Side Resources	3.7%	3.9%	4.2%	4.5%	5.9%	7.4%	8.9%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-39. Projected Demand-Side Resource Peak Load Impact in Louisiana through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

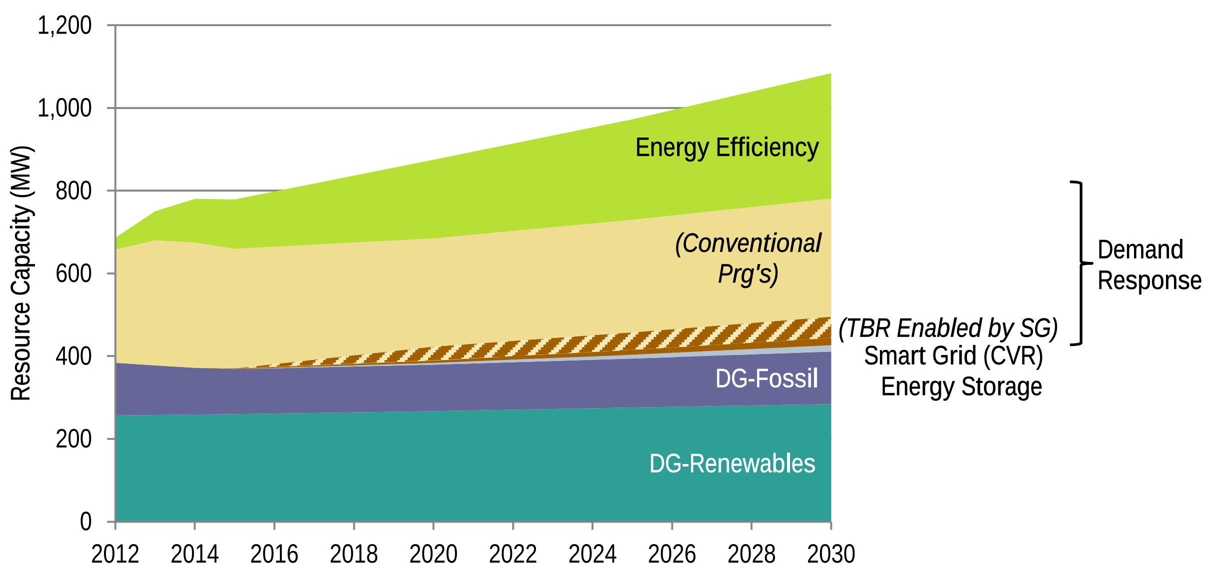
A.14 Maine[81]

Table A-40. Projected Demand-Side Resource Capacity in Maine through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	29	70	106	120	190	243	303
Demand Response (conventional)	274	302	303	289	262	272	286
Demand Response (smart grid-enabled)*	0	0	0	0	34	42	51
Energy Storage	0	0	0	0	4	9	15
DG-Fossil	127	120	113	109	112	118	127
DG-Renewables	257	258	259	260	267	276	284
Smart Grid (CVR)	0	0	0	2	6	12	17
TOTAL	686	750	780	779	875	972	1,084

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-40. Projected Demand-Side Resource Capacity in Maine through 2030



[81] EE and DR forecasts are based on ISO-NE's 2012 Forecast Data File.

Table A-41. Projected Demand-Side Resource Annual Energy Impact in Maine through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	184	449	676	764	1,216	1,553	1,938
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	151	146	141	139	151	167	188
DG-Renewables	1,105	1,107	1,111	1,113	1,135	1,164	1,192
Smart Grid [a c]	0	0	0	1	4	9	17
TOTAL	1,440	1,703	1,928	2,017	2,506	2,893	3,335
Total Annual Electricity Consumption (AEC) [d]	11,515	11,614	11,713	11,614	11,912	12,209	12,110
% of AEC Supported by Demand-Side Resources	12.5%	14.7%	16.5%	17.4%	21.0%	23.7%	27.5%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-41. Projected Demand-Side Resource Annual Energy Impact in Maine through 2030

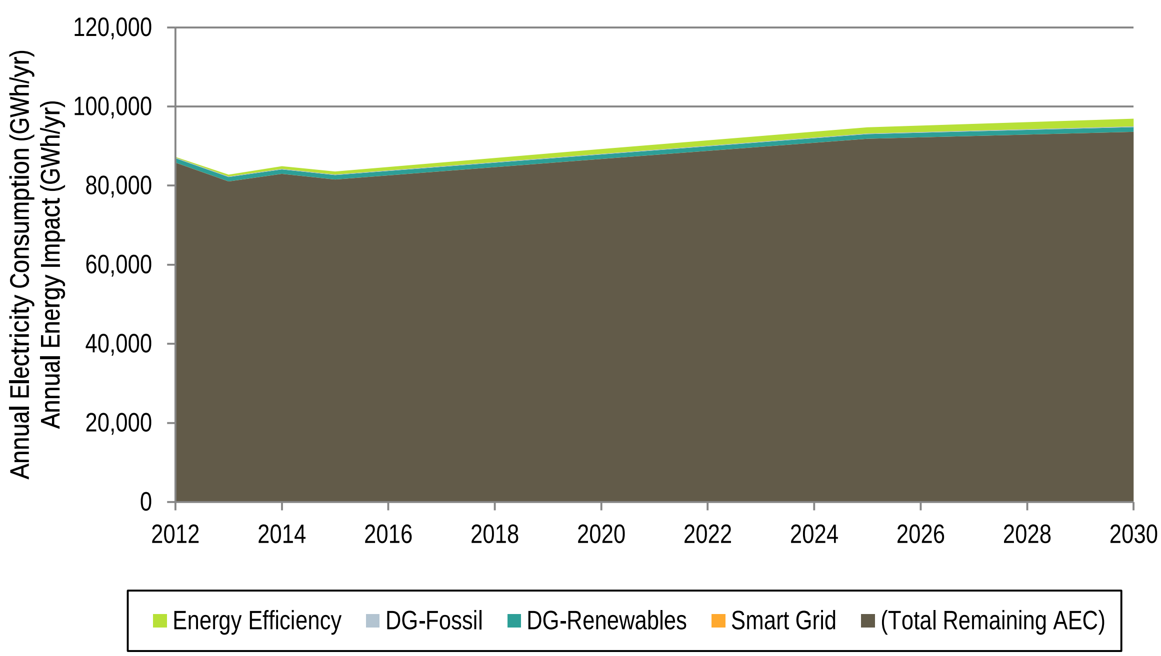
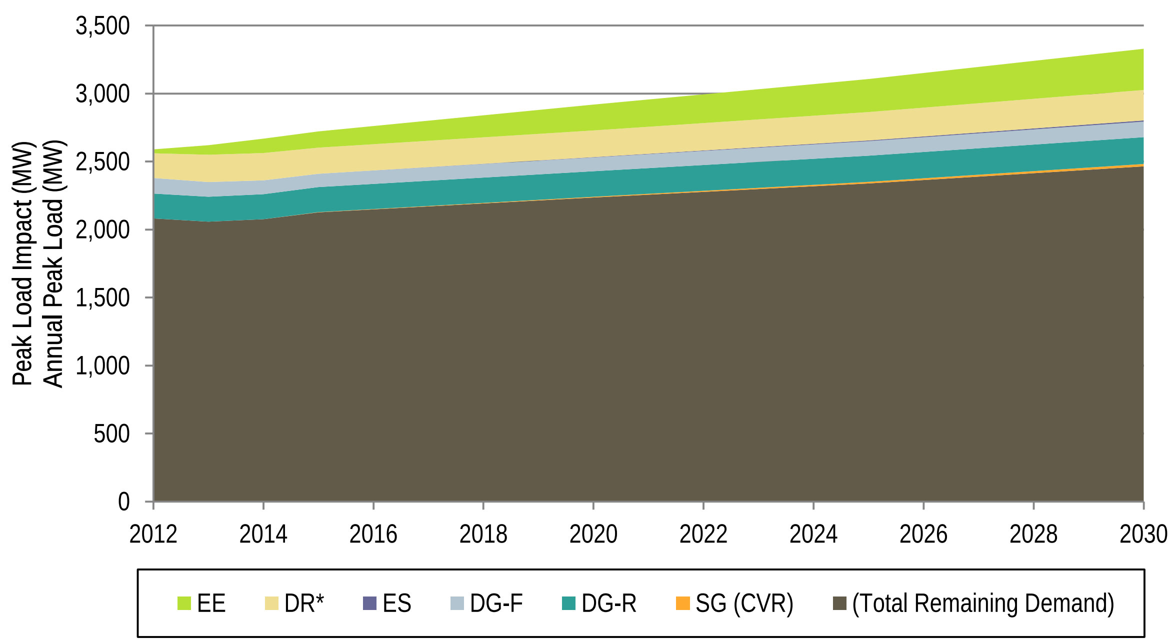


Table A-42. Projected Demand-Side Resource Peak Load Impact in Maine through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	29	70	106	120	190	243	303
Demand Response (conventional)	182	201	201	192	181	190	201
Demand Response (smart grid-enabled)*	0	0	0	0	15	19	23
Energy Storage	0	0	0	0	3	5	9
DG-Fossil	115	108	102	98	101	107	114
DG-Renewables	183	183	184	184	188	193	197
Smart Grid (CVR)	0	0	0	2	6	12	17
TOTAL	508	562	592	595	683	768	864
Total Annual Peak Load	2,589	2,620	2,668	2,721	2,919	3,106	3,329
% of Peak Load Supported by Demand-Side Resources	19.6%	21.5%	22.2%	21.9%	23.4%	24.7%	26.0%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-42. Projected Demand-Side Resource Peak Load Impact in Maine through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

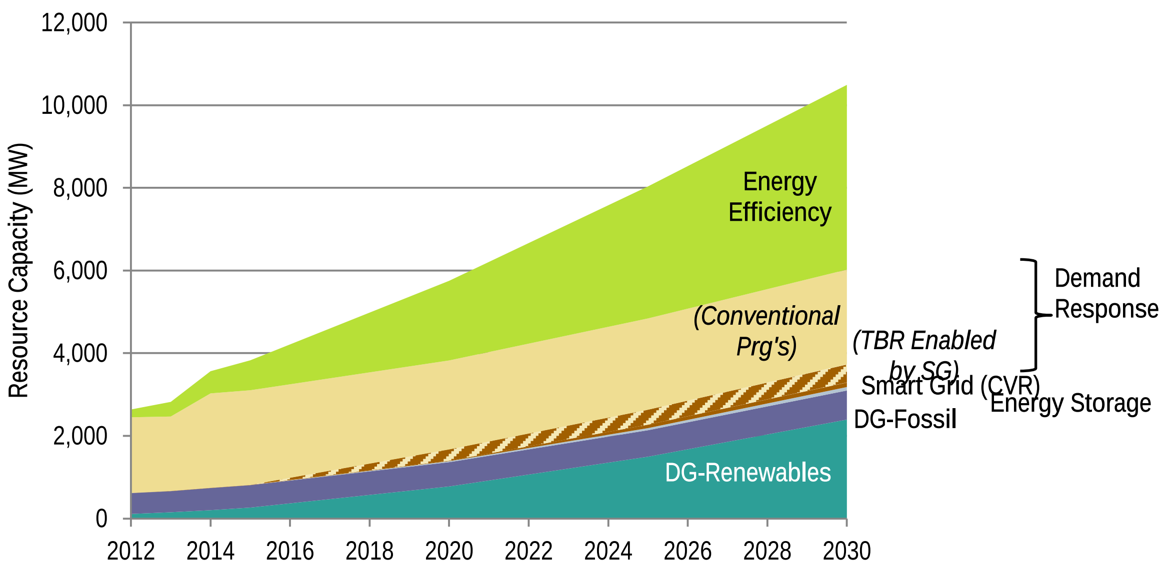
A.15 Maryland[82]

Table A-43. Projected Demand-Side Resource Capacity in Maryland through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	189	354	537	725	1,927	3,194	4,469
Demand Response (conventional)	1,830	1,800	2,284	2,290	2,153	2,208	2,294
Demand Response (smart grid-enabled)*	0	0	0	0	272	362	440
Energy Storage	0	0	0	0	24	51	84
DG-Fossil	506	511	536	542	588	641	704
DG-Renewables	111	152	202	265	776	1,496	2,393
Smart Grid (CVR)	3	6	6	6	11	83	107
TOTAL	2,638	2,822	3,564	3,828	5,751	8,035	10,491

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-43. Projected Demand-Side Resource Capacity in Maryland through 2030



[82] Navigant adjusted the units reported in the survey results for PEPCO to be consistent with the other data collected for PEPCO and other PHI utilities.

Table A-44. Projected Demand-Side Resource Annual Energy Impact in Maryland through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	764	1,431	2,167	2,926	7,781	12,899	18,047
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	858	875	919	938	1,054	1,187	1,340
DG-Renewables	360	421	491	578	1,249	2,193	3,375
Smart Grid [a c]	22	50	50	50	99	175	202
TOTAL	2,005	2,777	3,626	4,492	10,183	16,453	22,965
Total Annual Electricity Consumption (AEC) [d]	63,687	62,897	63,687	62,108	69,126	72,459	74,126
% of AEC Supported by Demand-Side Resources	3.1%	4.4%	5.7%	7.2%	14.7%	22.7%	31.0%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-44. Projected Demand-Side Resource Annual Energy Impact in Maryland through 2030

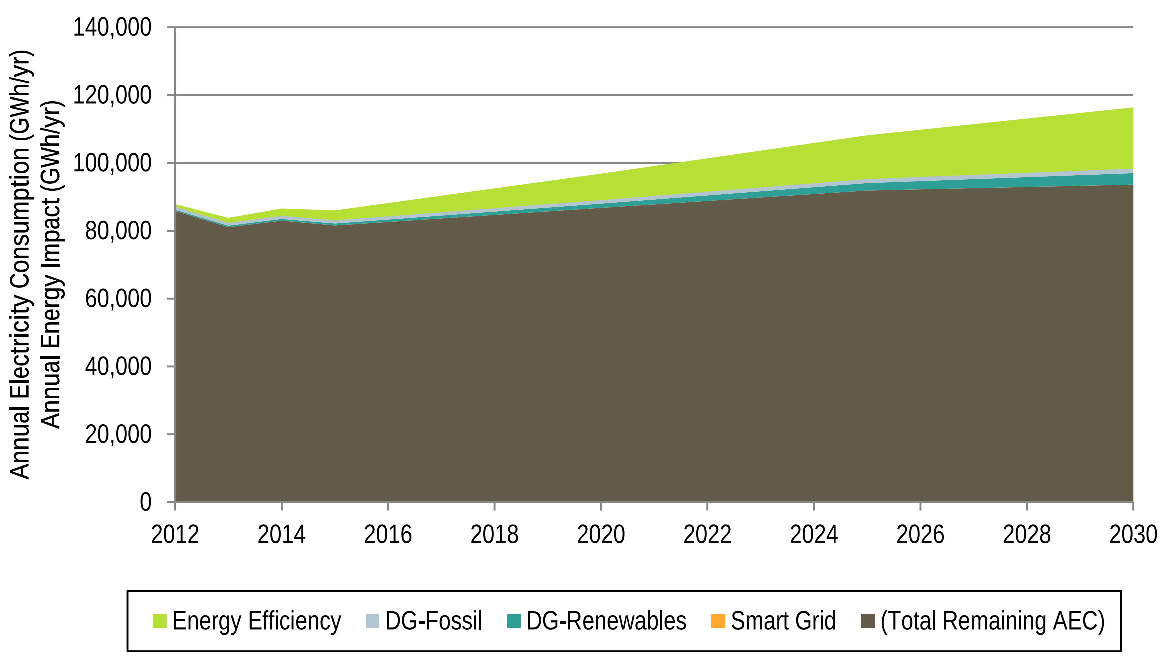


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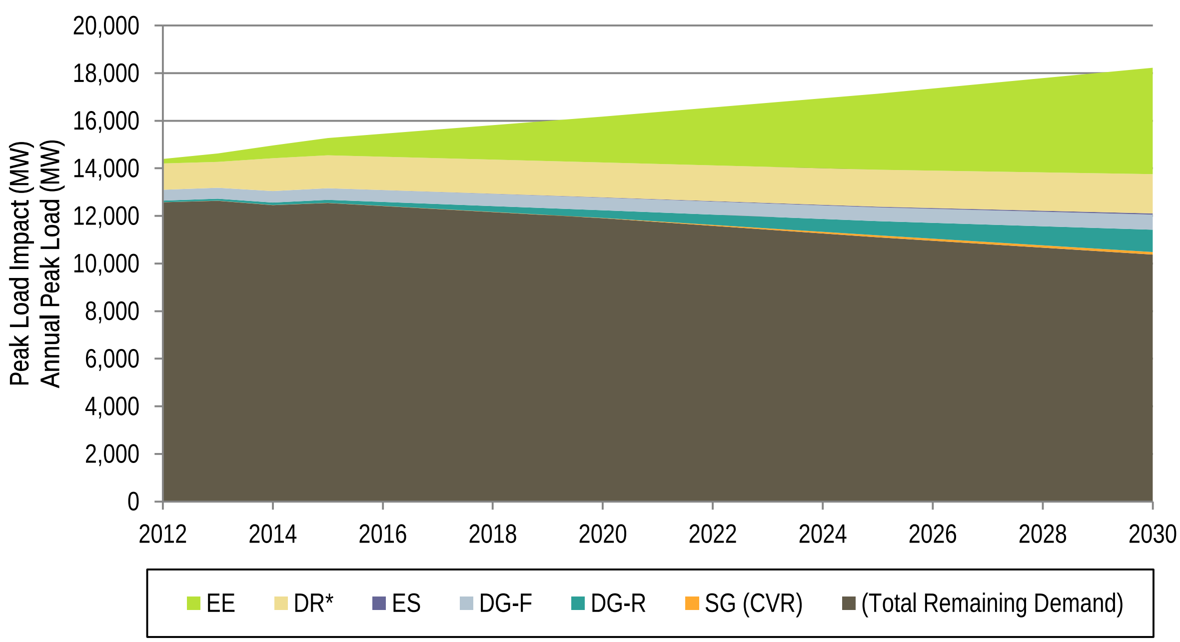
Table A-45. Projected Demand-Side Resource Peak Load Impact in Maryland through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	189	354	537	725	1,927	3,194	4,469
Demand Response (conventional)	1,105	1,087	1,379	1,383	1,343	1,390	1,453
Demand Response (smart grid-enabled)*	0	0	0	0	123	163	198
Energy Storage	0	0	0	0	14	30	50
DG-Fossil	455	459	483	488	529	577	633
DG-Renewables	67	84	103	128	322	596	938
Smart Grid (CVR)	3	6	6	6	11	83	107
TOTAL	1,819	1,990	2,507	2,730	4,268	6,032	7,848
Total Annual Peak Load	14,393	14,624	14,960	15,271	16,172	17,134	18,224
% of Peak Load Supported by Demand-Side Resources	12.6%	13.6%	16.8%	17.9%	26.4%	35.2%	43.1%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-45. Projected Demand-Side Resource Peak Load Impact in Maryland through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

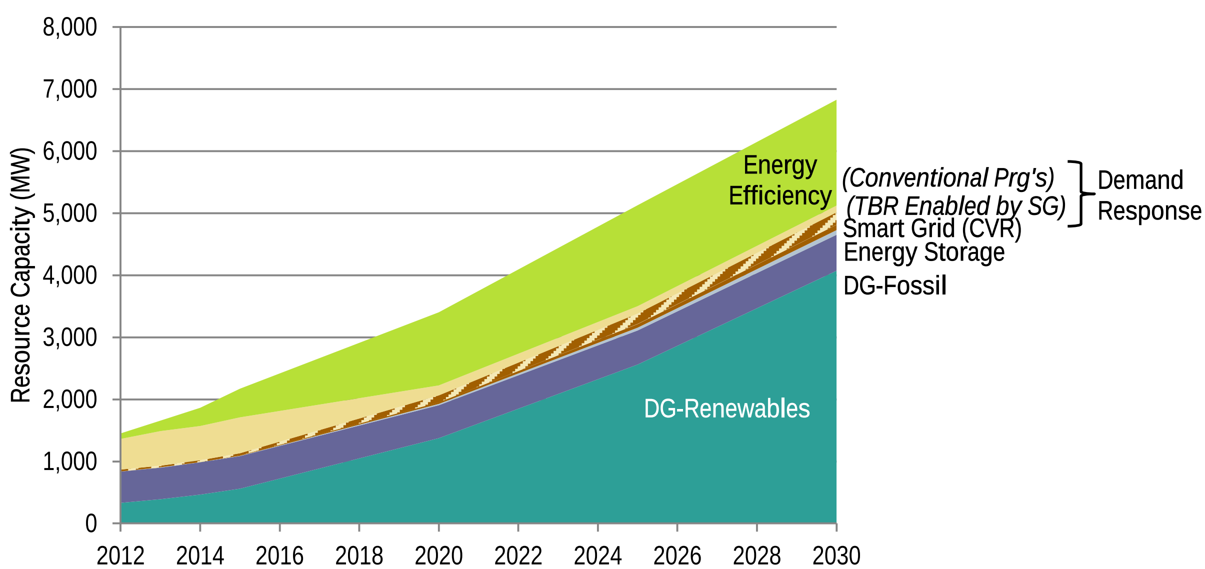
A.16 Massachusetts[83]

Table A-46. Projected Demand-Side Resource Capacity in Massachusetts through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	89	169	294	462	1,178	1,627	1,706
Demand Response (conventional)	495	556	551	582	149	34	7
Demand Response (smart grid-enabled)*	29	30	30	30	122	255	303
Energy Storage	2	4	4	4	21	45	75
DG-Fossil	505	508	521	525	531	549	579
DG-Renewables	332	391	465	560	1,374	2,561	4,072
Smart Grid (CVR)	0	0	0	8	27	57	85
TOTAL	1,451	1,657	1,864	2,171	3,403	5,128	6,827

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-46. Projected Demand-Side Resource Capacity in Massachusetts through 2030



[83] EE and DR forecasts are based on ISO-NE's 2012 Forecast Data File. The near-term Demand Response forecasts for New England states are based on the Real-Time Demand Response cleared in the primary Forward Capacity Auctions for ISO-NE, which show a significant decrease in committed DR capacity (approximately 1400 MW in 2015 to less than 900 MW in 2016). While this may be due to characteristics specific to New England's market, it is too soon to know whether increased availability of smart grid-enabled time-based rate programs in the area may influence the market trend. Navigant scaled back the forecast of Massachusetts's smart grid-enabled time-based rate programs in order to maintain consistency with the forecast for overall DR resource capacity. This assessment assumes that the overall DR capacity committed in 2016 grows gradually from 2016 through 2030.

Table A-47. Projected Demand-Side Resource Annual Energy Impact in Massachusetts through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	502	953	1,657	2,605	6,651	9,184	9,628
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	768	781	807	821	882	962	1,065
DG-Renewables	1,080	1,163	1,262	1,388	2,416	3,915	5,825
Smart Grid [a c]	0	0	0	4	18	42	83
TOTAL	2,351	2,897	3,726	4,817	9,967	14,103	16,601
Total Annual Electricity Consumption (AEC) [d]	56,053	56,536	57,020	56,536	57,986	59,436	58,952
% of AEC Supported by Demand-Side Resources	4.2%	5.1%	6.5%	8.5%	17.2%	23.7%	28.2%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-47. Projected Demand-Side Resource Annual Energy Impact in Massachusetts through 2030

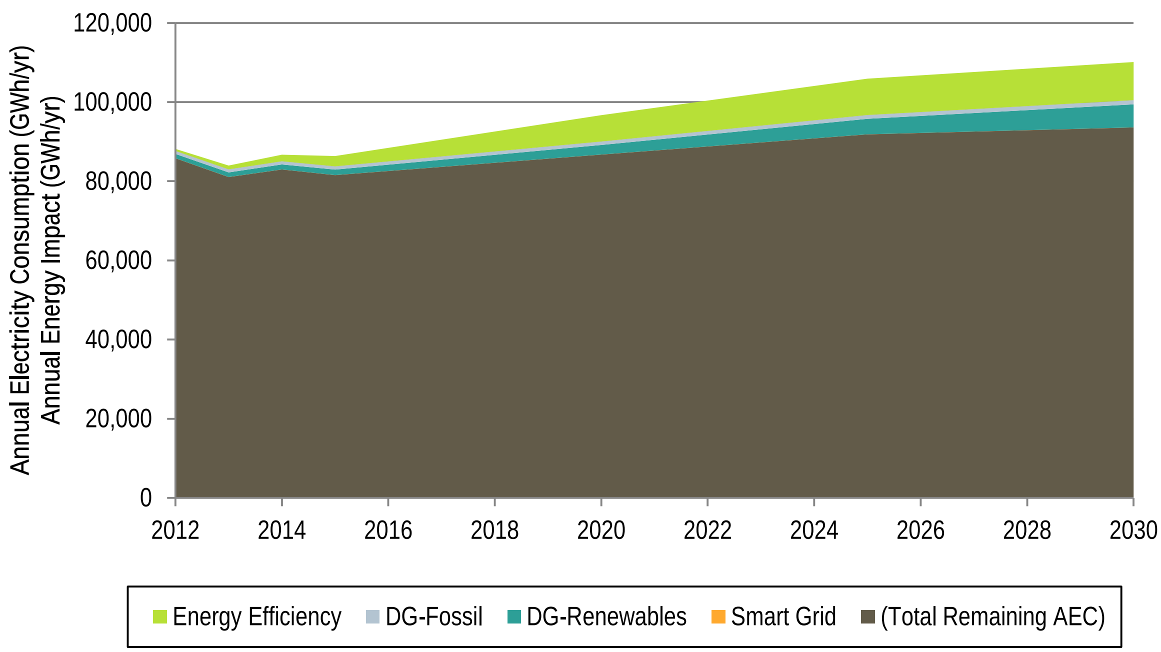
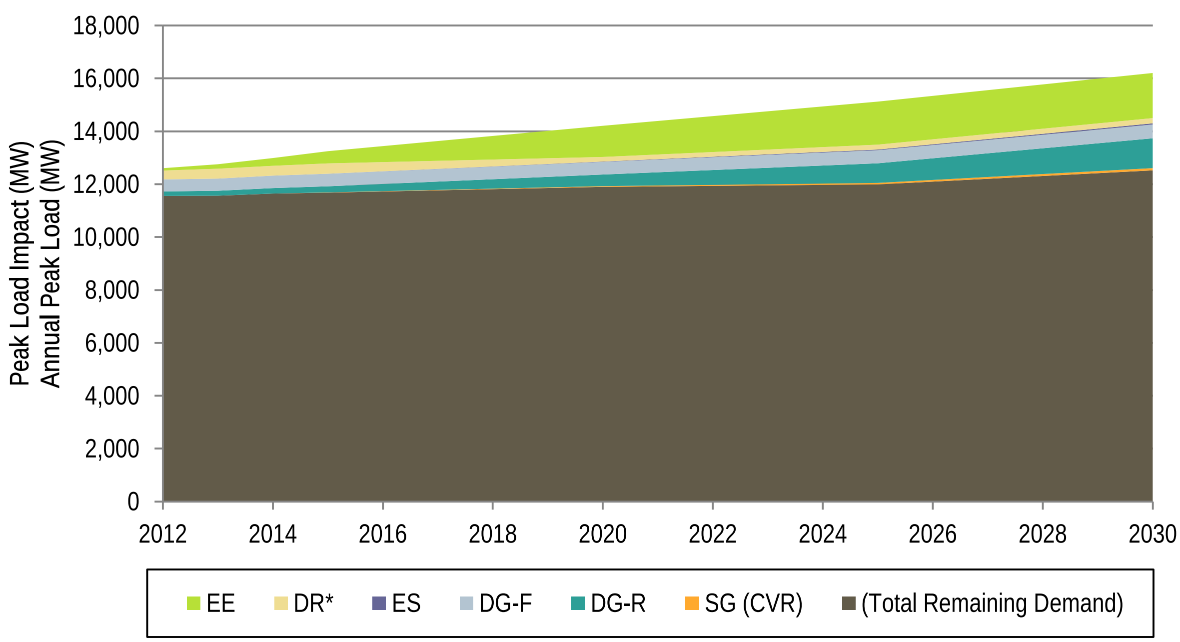


Table A-48. Projected Demand-Side Resource Peak Load Impact in Massachusetts through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	89	169	294	462	1,178	1,627	1,706
Demand Response (conventional)	322	361	358	378	118	70	62
Demand Response (smart grid-enabled)*	13	14	14	14	55	115	136
Energy Storage	1	2	2	2	12	26	45
DG-Fossil	454	457	469	473	478	494	521
DG-Renewables	171	187	207	232	440	742	1,128
Smart Grid (CVR)	0	0	0	8	27	57	85
TOTAL	1,050	1,190	1,342	1,567	2,309	3,131	3,682
Total Annual Peak Load	12,604	12,754	12,988	13,247	14,207	15,122	16,205
% of Peak Load Supported by Demand-Side Resources	8.3%	9.3%	10.3%	11.8%	16.2%	20.7%	22.7%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-48. Projected Demand-Side Resource Peak Load Impact in Massachusetts through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

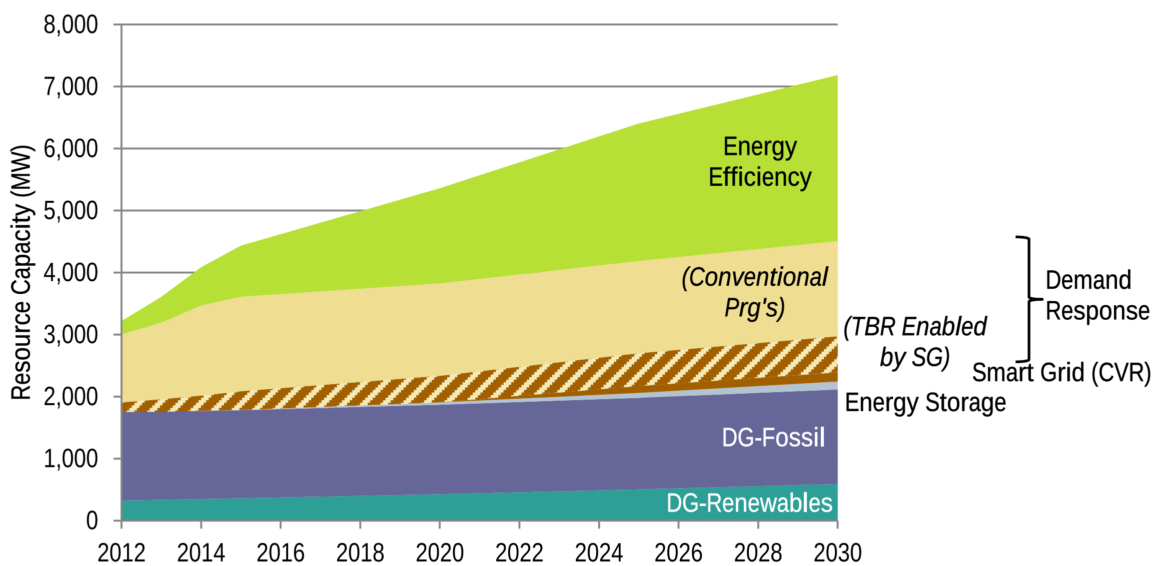
A.17 Michigan[84]

Table A-49. Projected Demand-Side Resource Capacity in Michigan through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	216	419	619	825	1,537	2,219	2,679
Demand Response (conventional)	1,096	1,234	1,452	1,524	1,488	1,487	1,535
Demand Response (smart grid-enabled)*	154	194	244	302	429	527	581
Energy Storage	1	2	2	2	38	79	129
DG-Fossil	1,429	1,426	1,423	1,421	1,443	1,477	1,523
DG-Renewables	322	335	346	359	424	502	590
Smart Grid (CVR)	0	0	0	0	1	112	147
TOTAL	3,218	3,608	4,086	4,434	5,360	6,404	7,185

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-49. Projected Demand-Side Resource Capacity in Michigan through 2030



[84] Navigant excluded approximately 3,000 MW of commercial and industrial time-of-use rate program reported by The Detroit Edison Company in FERC's DR survey, based on discussions with the utility.

Table A-50. Projected Demand-Side Resource Annual Energy Impact in Michigan through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	1,064	2,057	3,043	4,056	7,554	10,908	13,169
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	3,019	3,026	3,033	3,041	3,089	3,159	3,253
DG-Renewables	1,624	1,667	1,701	1,739	1,896	2,096	2,348
Smart Grid [a c]	0	0	1	2	6	107	148
TOTAL	5,707	6,750	7,777	8,838	12,545	16,270	18,919
Total Annual Electricity Consumption (AEC) [d]	91,425	93,969	86,039	91,575	91,126	97,859	101,301
% of AEC Supported by Demand-Side Resources	6.2%	7.2%	9.0%	9.7%	13.8%	16.6%	18.7%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-50. Projected Demand-Side Resource Annual Energy Impact in Michigan through 2030

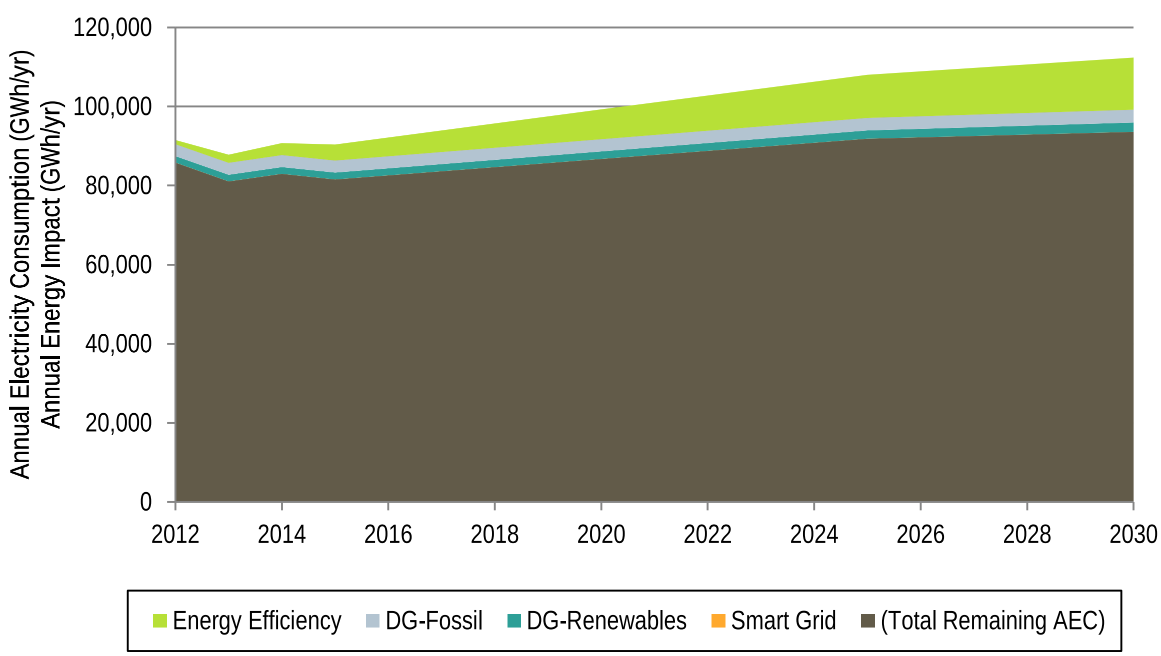
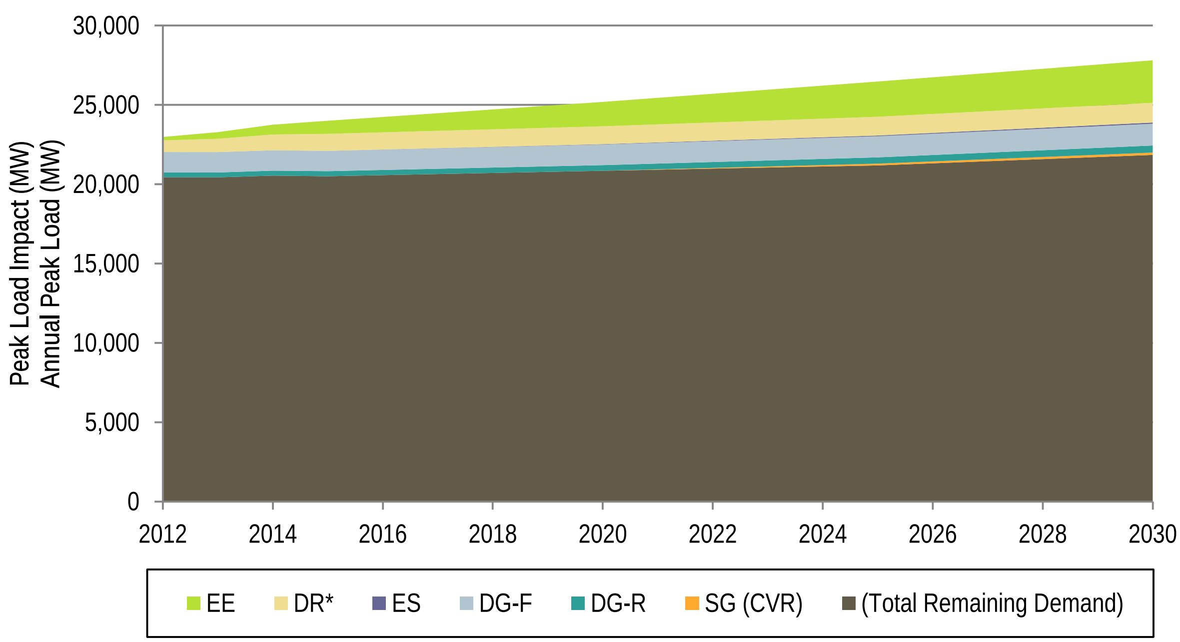


Table A-51. Projected Demand-Side Resource Peak Load Impact in Michigan through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	216	419	619	825	1,537	2,219	2,679
Demand Response (conventional)	665	751	886	936	932	945	981
Demand Response (smart grid-enabled)*	69	87	110	136	193	237	262
Energy Storage	1	2	2	2	22	46	76
DG-Fossil	1,286	1,283	1,281	1,279	1,299	1,330	1,371
DG-Renewables	298	306	313	320	354	396	446
Smart Grid (CVR)	0	0	0	0	1	112	147
TOTAL	2,535	2,848	3,210	3,499	4,339	5,286	5,963
Total Annual Peak Load	22,975	23,279	23,749	23,997	25,184	26,468	27,806
% of Peak Load Supported by Demand-Side Resources	11.0%	12.2%	13.5%	14.6%	17.2%	20.0%	21.4%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-51. Projected Demand-Side Resource Peak Load Impact in Michigan through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

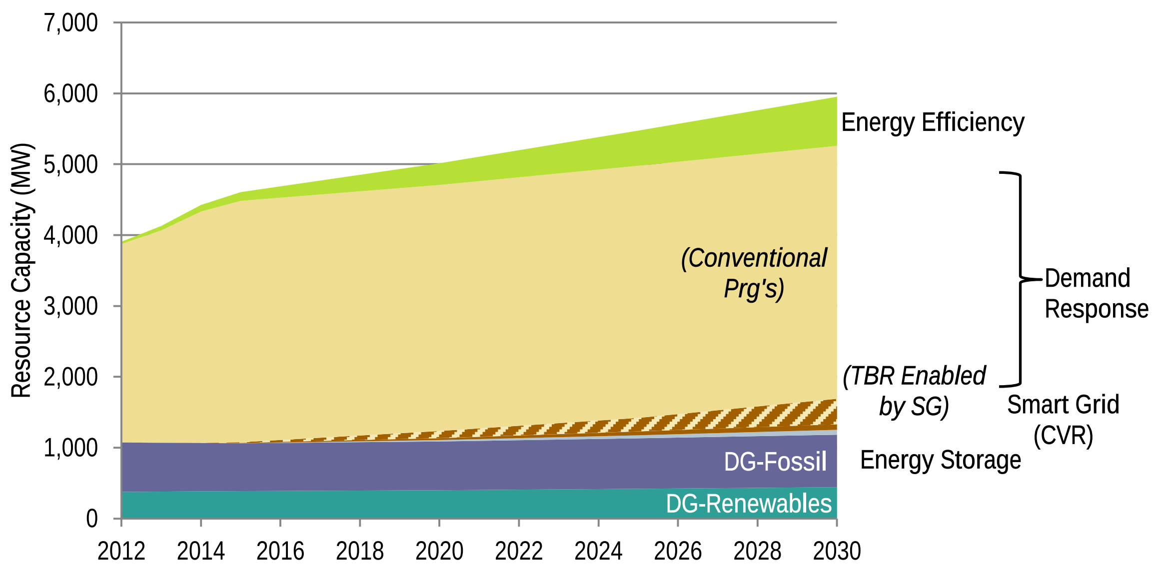
A.18 Minnesota[85]

Table A-52. Projected Demand-Side Resource Capacity in Minnesota through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	32	63	93	124	307	496	693
Demand Response (conventional)	2,798	2,992	3,260	3,406	3,471	3,557	3,570
Demand Response (smart grid-enabled)*	2	3	5	6	103	192	359
Energy Storage	1	1	1	1	20	43	69
DG-Fossil	696	689	682	674	688	712	740
DG-Renewables	377	380	384	387	400	420	442
Smart Grid (CVR)	0	0	0	8	26	54	79
TOTAL	3,906	4,129	4,425	4,606	5,014	5,474	5,952

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-52. Projected Demand-Side Resource Capacity in Minnesota through 2030



[85] The forecast for Minnesota assumes that the majority of the EE and DR reported for by Northern States Power Company (Minnesota) occur in MN, as opposed to the other nearby states also served by the utility.

Table A-53. Projected Demand-Side Resource Annual Energy Impact in Minnesota through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	150	294	435	577	1,429	2,312	3,229
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	1,153	1,132	1,110	1,090	1,102	1,163	1,240
DG-Renewables	1,260	1,272	1,284	1,293	1,331	1,393	1,467
Smart Grid [a c]	0	0	0	5	23	53	107
TOTAL	2,563	2,698	2,829	2,965	3,885	4,921	6,042
Total Annual Electricity Consumption (AEC) [d]	73,474	72,846	75,567	71,799	73,474	74,939	76,405
% of AEC Supported by Demand-Side Resources	3.5%	3.7%	3.7%	4.1%	5.3%	6.6%	7.9%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-53. Projected Demand-Side Resource Annual Energy Impact in Minnesota through 2030

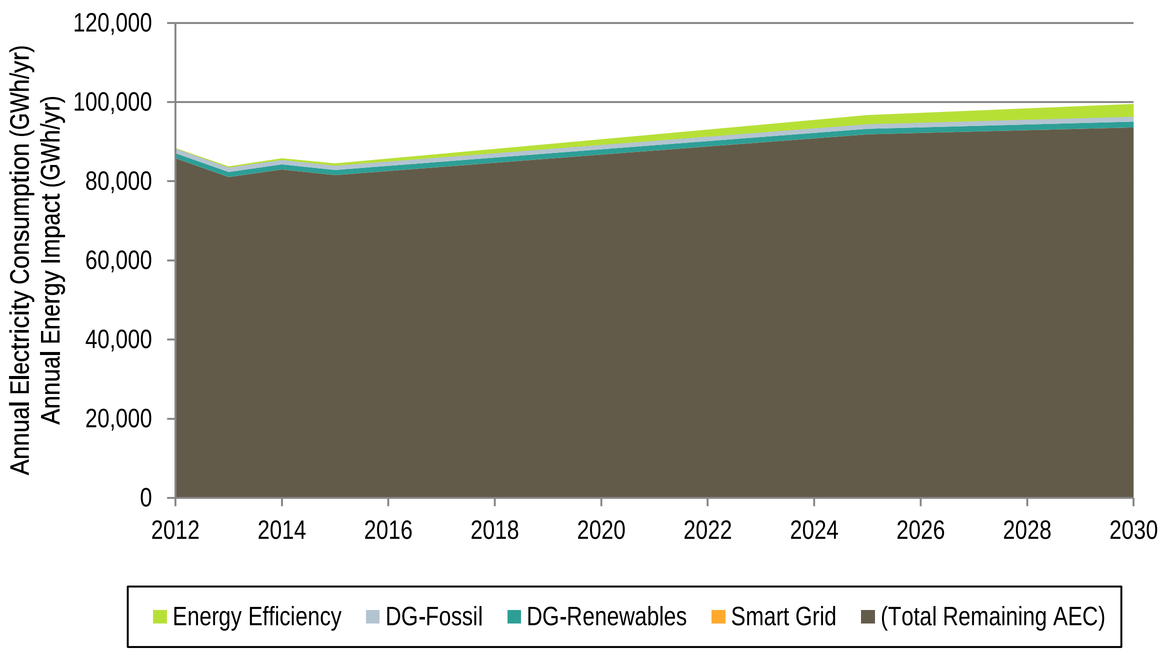
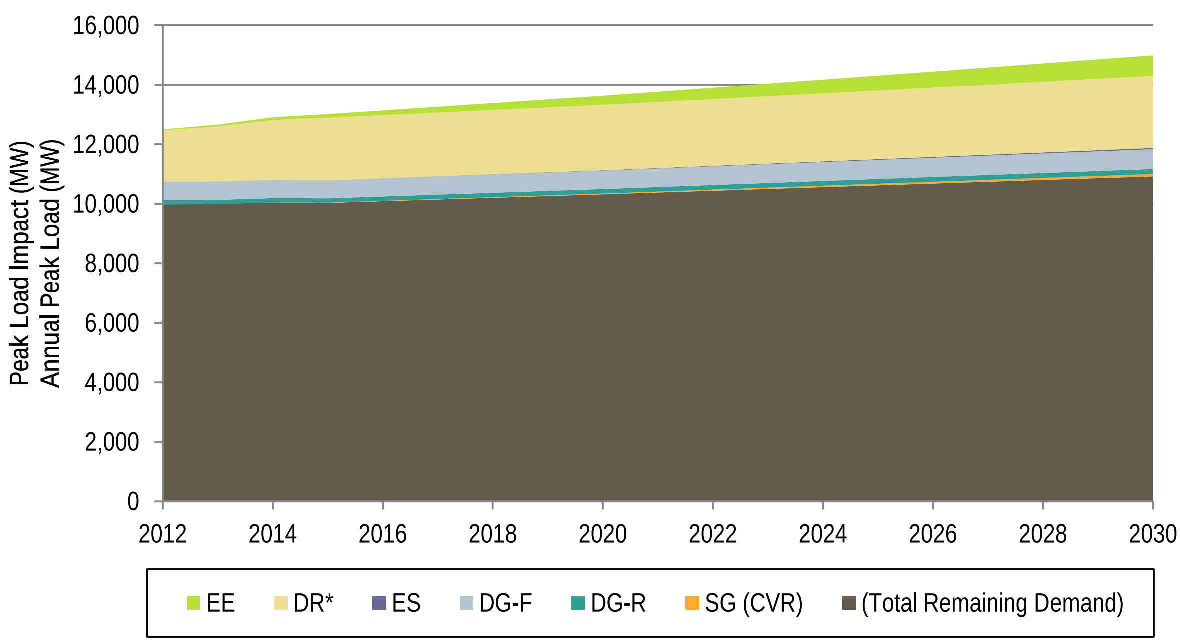


Table A-54. Projected Demand-Side Resource Peak Load Impact in Minnesota through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	32	63	93	124	307	496	693
Demand Response (conventional)	1,724	1,843	2,008	2,098	2,155	2,223	2,258
Demand Response (smart grid-enabled)*	1	2	2	3	46	86	161
Energy Storage	1	1	1	1	12	25	41
DG-Fossil	627	620	613	607	619	641	666
DG-Renewables	142	144	145	146	153	161	170
Smart Grid (CVR)	0	0	0	8	26	54	79
TOTAL	2,526	2,673	2,863	2,988	3,316	3,686	4,068
Total Annual Peak Load	12,502	12,660	12,908	13,016	13,634	14,305	14,988
% of Peak Load Supported by Demand-Side Resources	20.2%	21.1%	22.2%	23.0%	24.3%	25.8%	27.1%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-54. Projected Demand-Side Resource Peak Load Impact in Minnesota through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

A.19 Mississippi

Table A-55. Projected Demand-Side Resource Capacity in Mississippi through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	14	29	44	60	154	260	364
Demand Response (conventional)	560	585	625	636	657	672	680
Demand Response (smart grid-enabled)*	2	2	2	2	24	54	96
Energy Storage	0	0	0	0	20	43	71
DG-Fossil	218	215	213	210	207	204	200
DG-Renewables	3	3	4	4	6	7	9
Smart Grid (CVR)	0	0	0	0	9	18	29
TOTAL	797	835	887	911	1,076	1,258	1,449

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-55. Projected Demand-Side Resource Capacity in Mississippi through 2030

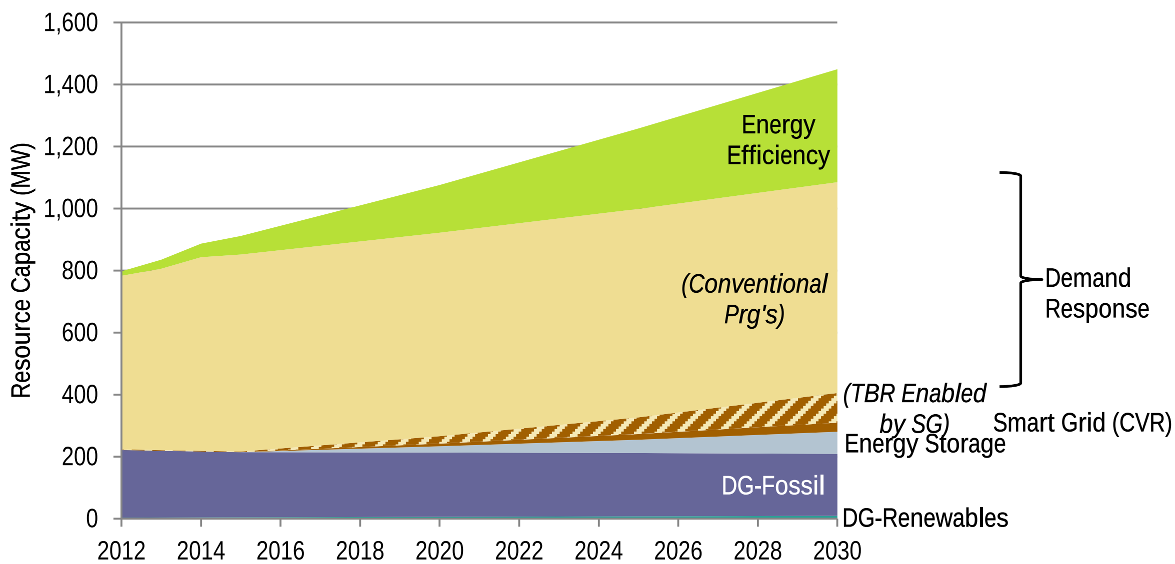


Table A-56. Projected Demand-Side Resource Annual Energy Impact in Mississippi through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	74	149	224	306	787	1,328	1,864
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	508	505	502	498	480	460	438
DG-Renewables	15	16	16	17	20	24	28
Smart Grid [a c]	0	0	0	0	8	17	25
TOTAL	597	669	741	821	1,295	1,828	2,355
Total Annual Electricity Consumption (AEC) [d]	48,346	45,743	46,858	46,115	49,338	52,561	53,924
% of AEC Supported by Demand-Side Resources	1.2%	1.5%	1.6%	1.8%	2.6%	3.5%	4.4%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-56. Projected Demand-Side Resource Annual Energy Impact in Mississippi through 2030

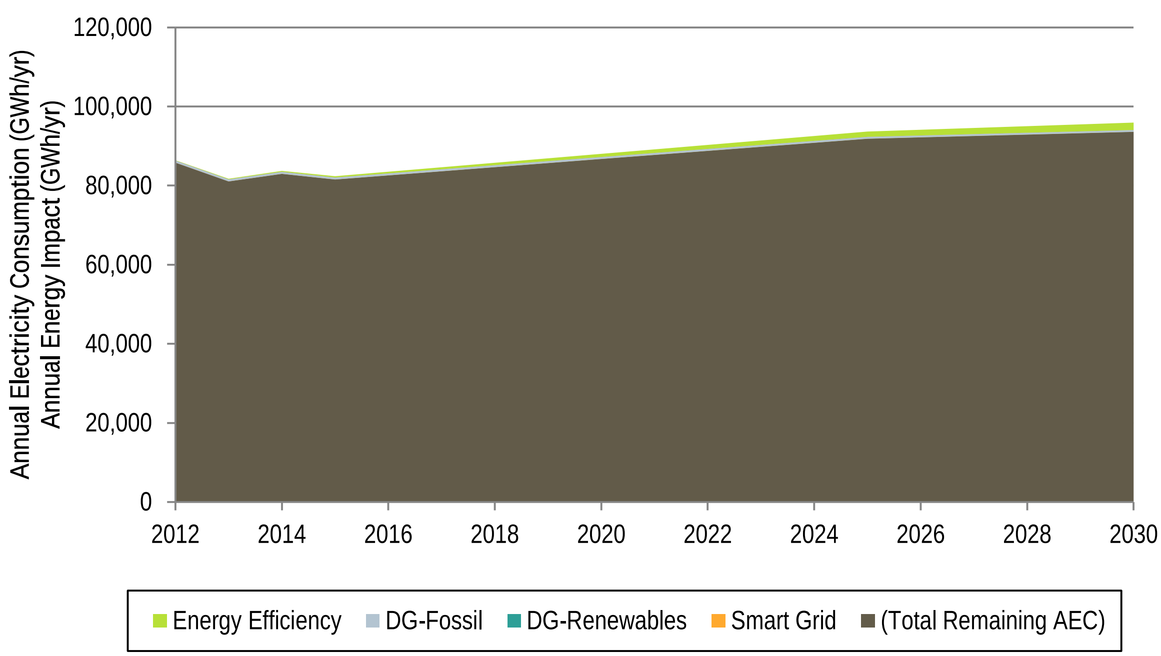


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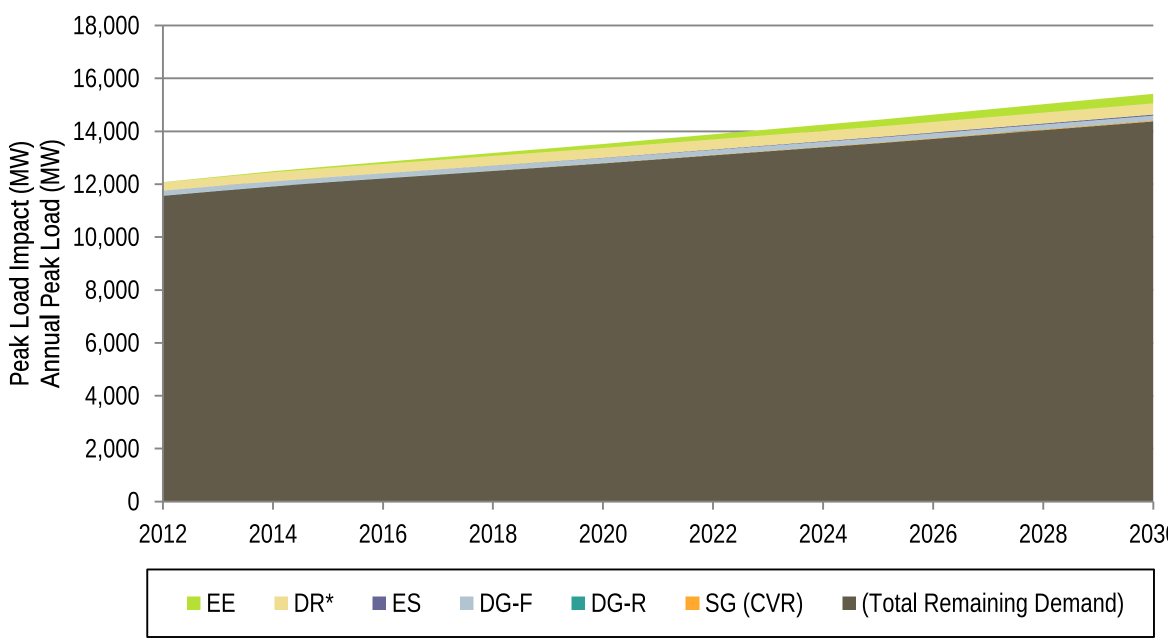
Table A-57. Projected Demand-Side Resource Peak Load Impact in Mississippi through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	14	29	44	60	154	260	364
Demand Response (conventional)	303	316	338	344	357	368	376
Demand Response (smart grid-enabled)*	1	1	1	1	11	24	43
Energy Storage	0	0	0	0	12	25	42
DG-Fossil	196	194	191	189	187	184	180
DG-Renewables	3	3	4	4	6	7	9
Smart Grid (CVR)	0	0	0	0	9	18	29
TOTAL	517	543	577	597	734	886	1,044
Total Annual Peak Load	12,077	12,286	12,491	12,671	13,520	14,434	15,416
% of Peak Load Supported by Demand-Side Resources	4.3%	4.4%	4.6%	4.7%	5.4%	6.1%	6.8%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-57. Projected Demand-Side Resource Peak Load Impact in Mississippi through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

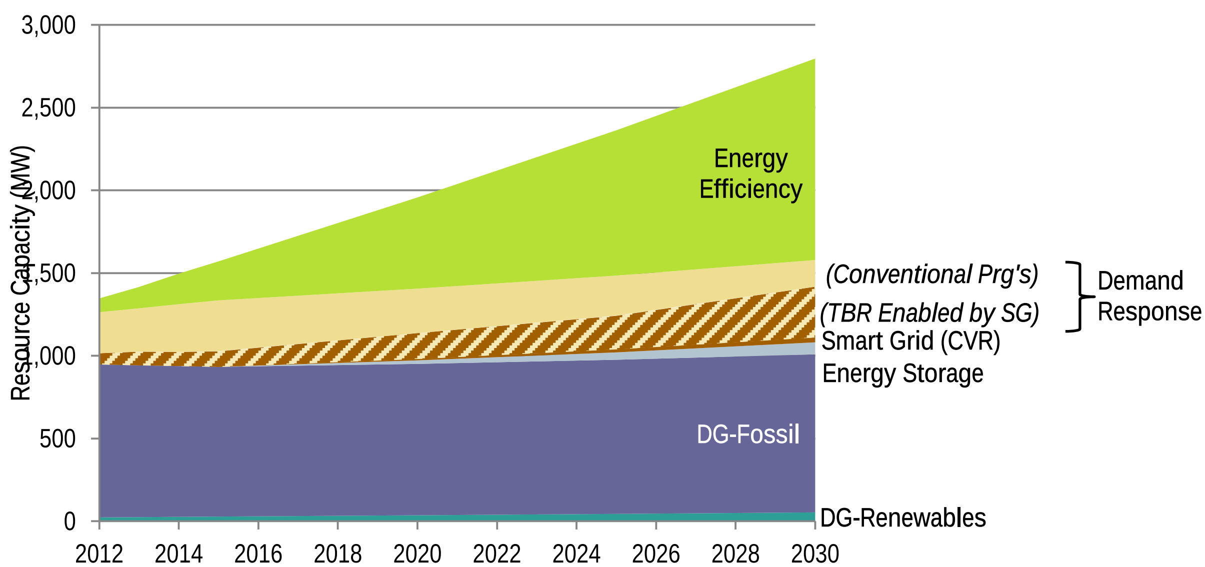
A.20 Missouri[86]

Table A-58. Projected Demand-Side Resource Capacity in Missouri through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	83	129	185	236	551	878	1,217
Demand Response (conventional)	248	262	289	307	268	241	161
Demand Response (smart grid-enabled)*	68	83	86	95	156	204	307
Energy Storage	0	0	0	0	21	45	73
DG-Fossil	924	917	911	905	915	931	955
DG-Renewables	24	25	27	29	36	45	54
Smart Grid (CVR)	0	0	0	0	9	19	30
TOTAL	1,347	1,416	1,497	1,571	1,957	2,363	2,796

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-58. Projected Demand-Side Resource Capacity in Missouri through 2030



[86] The forecast for Missouri assumes that the 2012 EE data available for Empire District Electric Company and Kansas City Power and Light Company are cumulative. Navigant used 2011 EIA-861 data to estimate the incremental annual savings achieved in 2012. Furthermore, the forecast assumes that the DR program capacity for Empire District Electric Company was constant for years 2012 through 2014.

Table A-59. Projected Demand-Side Resource Annual Energy Impact in Missouri through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	439	682	975	1,246	2,910	4,637	6,428
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	1,790	1,787	1,785	1,783	1,808	1,846	1,899
DG-Renewables	98	103	106	110	125	144	165
Smart Grid [a c]	0	0	0	0	14	29	44
TOTAL	2,327	2,571	2,865	3,139	4,858	6,655	8,536
Total Annual Electricity Consumption (AEC) [d]	90,716	89,941	93,301	88,648	90,716	92,525	94,334
% of AEC Supported by Demand-Side Resources	2.6%	2.9%	3.1%	3.5%	5.4%	7.2%	9.0%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-59. Projected Demand-Side Resource Annual Energy Impact in Missouri through 2030

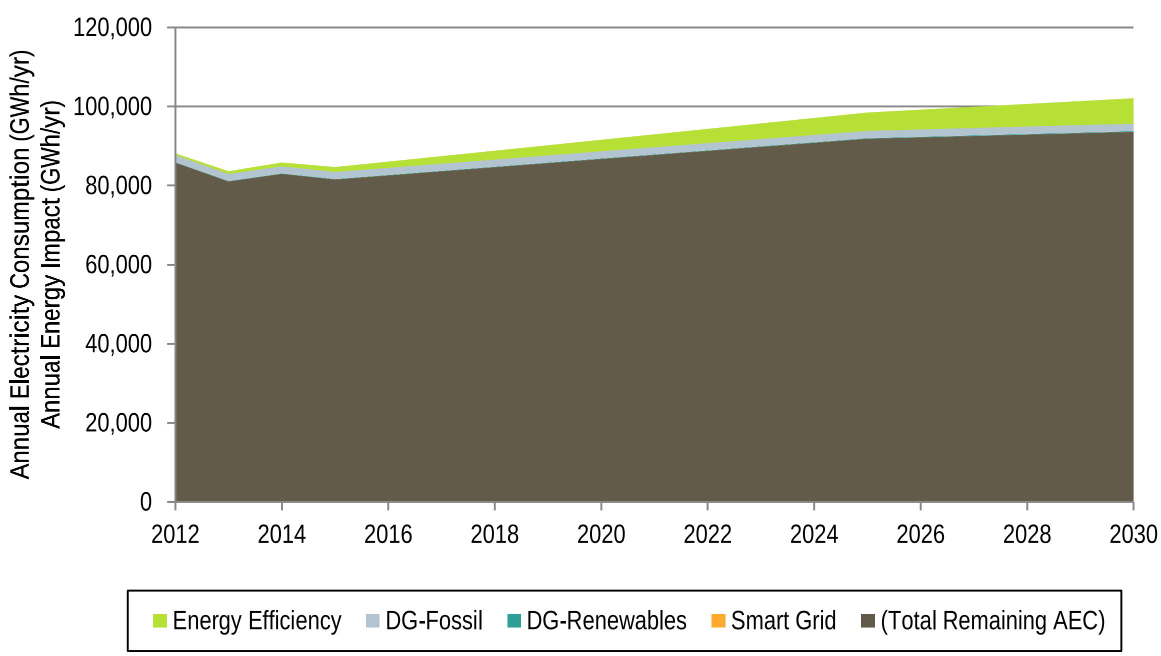


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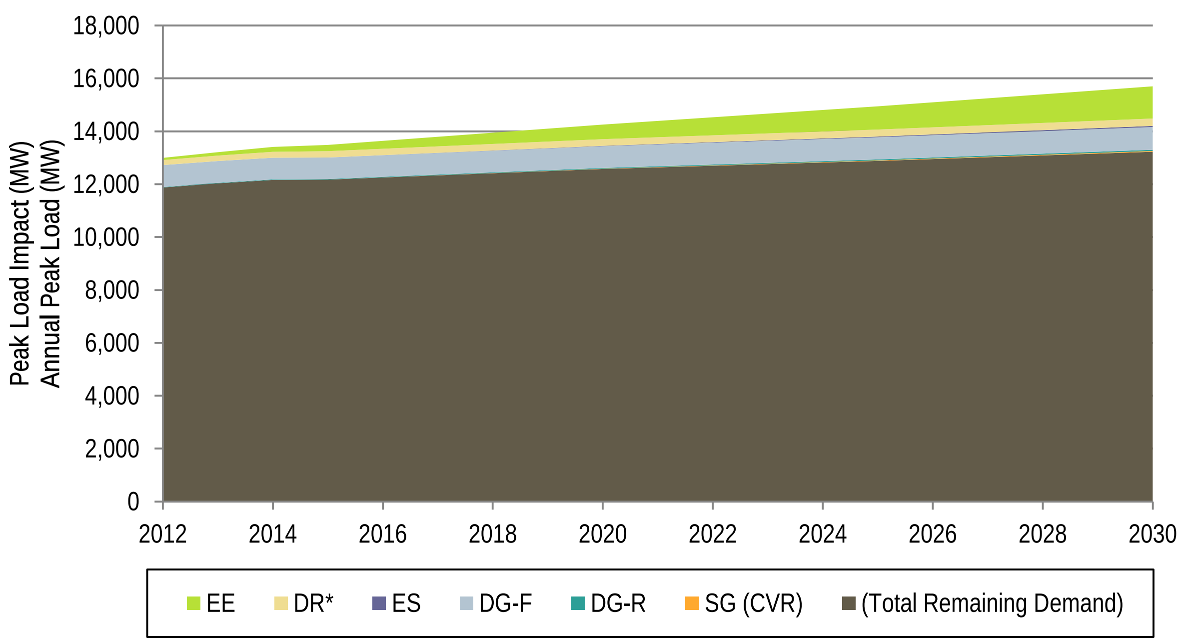
Table A-60. Projected Demand-Side Resource Peak Load Impact in Missouri through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	83	129	185	236	551	878	1,217
Demand Response (conventional)	158	168	185	197	183	174	141
Demand Response (smart grid-enabled)*	31	37	39	43	70	92	138
Energy Storage	0	0	0	0	12	26	43
DG-Fossil	832	826	820	814	823	838	860
DG-Renewables	16	18	19	21	29	37	45
Smart Grid (CVR)	0	0	0	0	9	19	30
TOTAL	1,119	1,178	1,247	1,311	1,678	2,063	2,474
Total Annual Peak Load	12,995	13,210	13,408	13,484	14,253	14,944	15,700
% of Peak Load Supported by Demand-Side Resources	8.6%	8.9%	9.3%	9.7%	11.8%	13.8%	15.8%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-60. Projected Demand-Side Resource Peak Load Impact in Missouri through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

A.21 Montana[87]

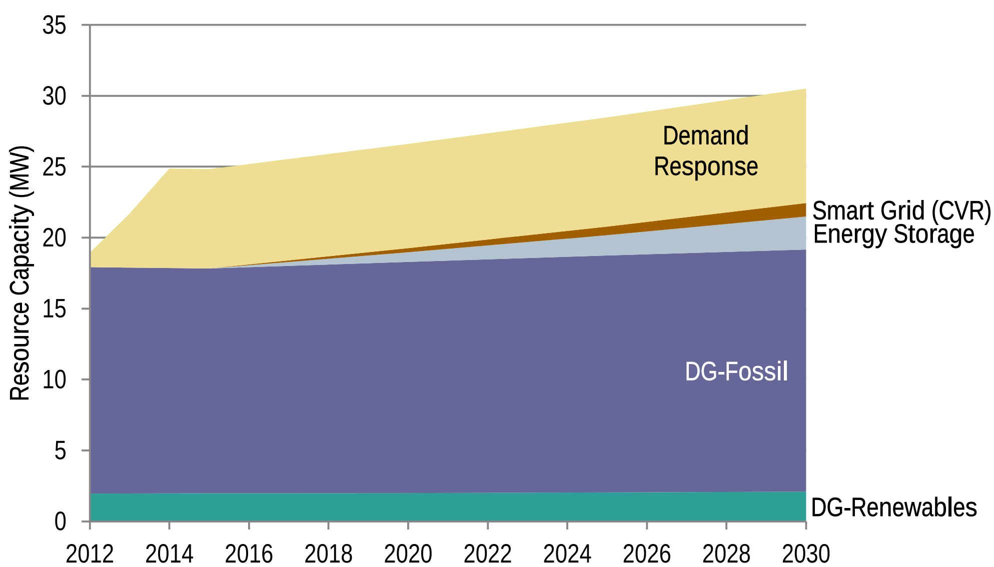
Note that the data in this section covers only the parts of Montana that are served by utilities within the Eastern Interconnection.

Table A-61. Projected Demand-Side Resource Capacity in Montana through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	0	0	0	0	0	0	0
Demand Response (conventional)	1	4	7	7	7	8	8
Demand Response (smart grid-enabled)*	0	0	0	0	0	0	0
Energy Storage	0	0	0	0	1	1	2
DG-Fossil	16	16	16	16	16	17	17
DG-Renewables	2	2	2	2	2	2	2
Smart Grid (CVR)	0	0	0	0	0	1	1
TOTAL	19	22	25	25	27	28	30

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-61. Projected Demand-Side Resource Capacity in Montana through 2030



[87] While this assessment included portions of Montana that fall within the Eastern Interconnection territory, publicly available data is not sufficient to estimate existing or forecasted EE resources in this state.

Table A-62. Projected Demand-Side Resource Annual Energy Impact in Montana through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	0	1	1	1	1	2	2
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	41	41	41	41	41	42	42
DG-Renewables	4	4	4	4	4	4	5
Smart Grid [a c]	0	0	0	0	0	0	1
TOTAL	46	46	46	46	47	48	49
Total Annual Electricity Consumption (AEC) [d]	1,224	1,214	1,259	1,196	1,224	1,249	1,273
% of AEC Supported by Demand-Side Resources	3.7%	3.8%	3.7%	3.9%	3.9%	3.9%	3.9%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-62. Projected Demand-Side Resource Annual Energy Impact in Montana through 2030

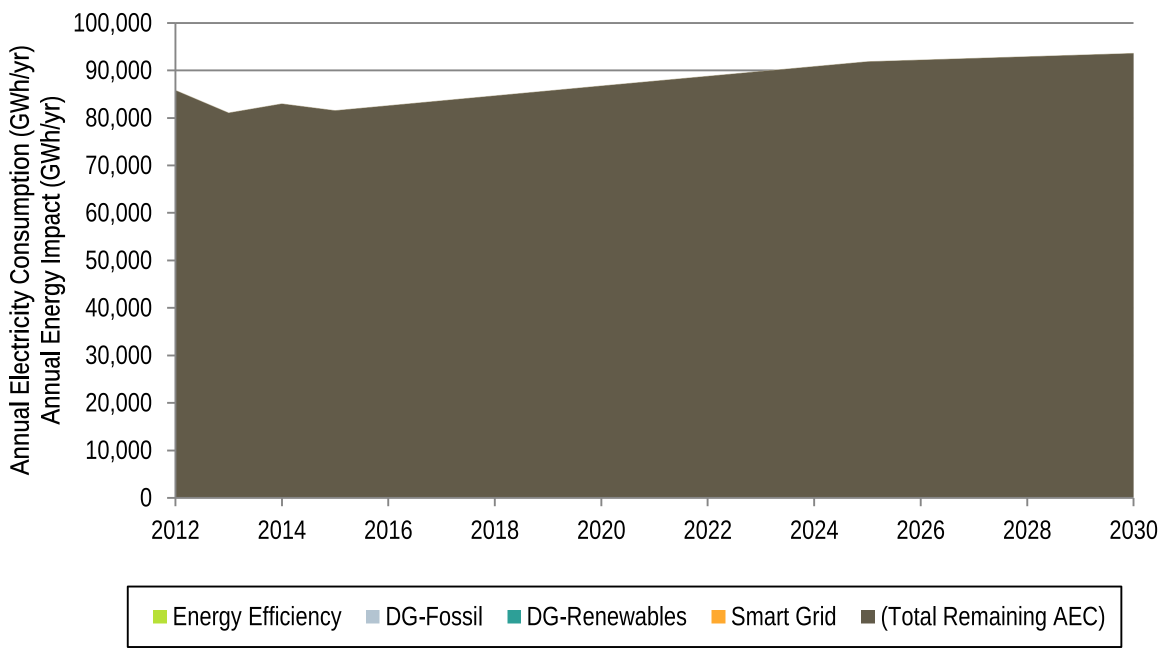
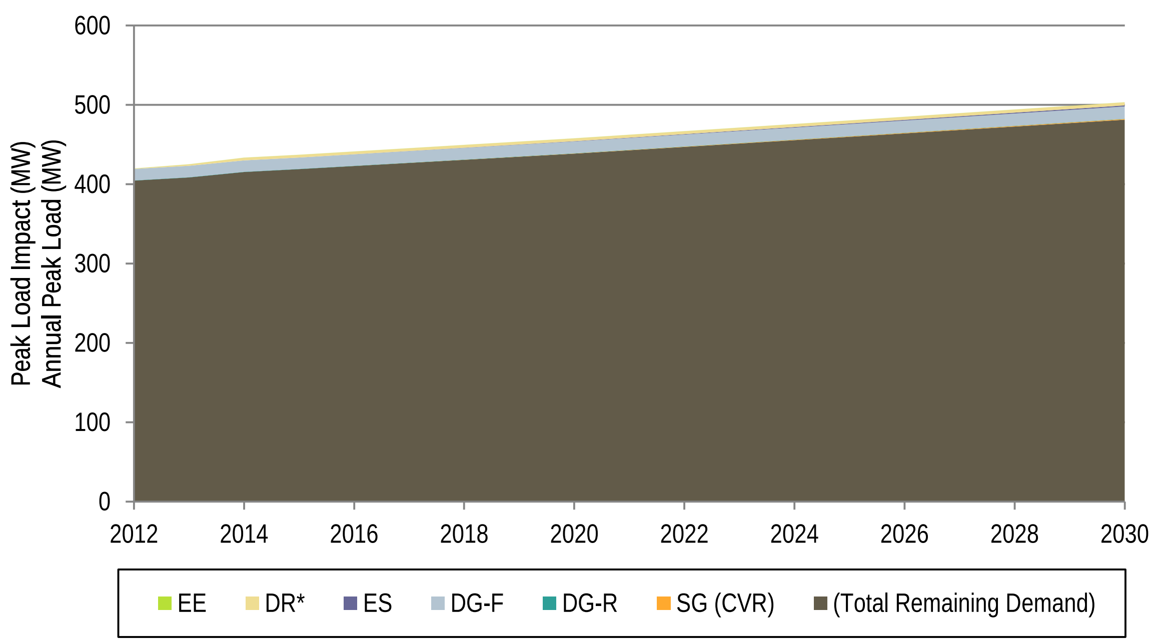


Table A-63. Projected Demand-Side Resource Peak Load Impact in Montana through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	0	0	0	0	0	0	0
Demand Response (conventional)	0	2	3	3	4	4	4
Demand Response (smart grid-enabled)*	0	0	0	0	0	0	0
Energy Storage	0	0	0	0	0	1	1
DG-Fossil	14	14	14	14	15	15	15
DG-Renewables	0	0	0	0	0	0	0
Smart Grid (CVR)	0	0	0	0	0	1	1
TOTAL	15	16	18	18	19	21	22
Total Annual Peak Load	420	425	433	437	458	480	503
% of Peak Load Supported by Demand-Side Resources	3.6%	3.9%	4.2%	4.1%	4.2%	4.3%	4.4%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-63. Projected Demand-Side Resource Peak Load Impact in Montana through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

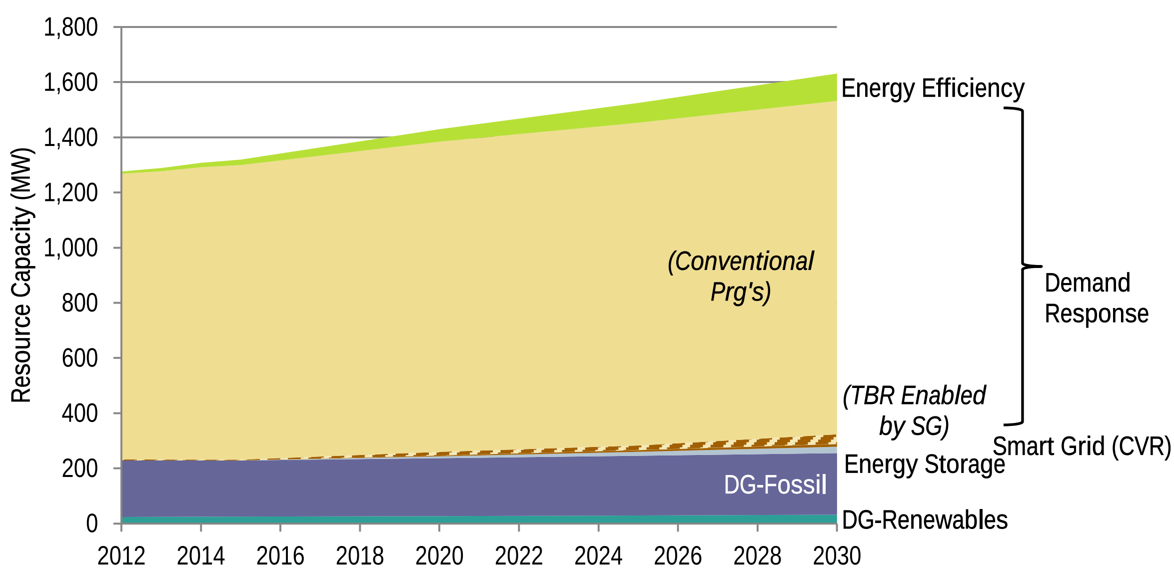
A.22 Nebraska[88]

Table A-64. Projected Demand-Side Resource Capacity in Nebraska through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	8	12	16	20	45	72	99
Demand Response (conventional)	1,036	1,045	1,060	1,068	1,124	1,170	1,209
Demand Response (smart grid-enabled)*	2	2	2	3	13	17	35
Energy Storage	0	0	0	0	7	14	23
DG-Fossil	207	206	205	203	210	217	223
DG-Renewables	23	24	25	25	27	29	32
Smart Grid (CVR)	0	0	0	0	3	6	9
TOTAL	1,276	1,289	1,308	1,319	1,430	1,525	1,631

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-64. Projected Demand-Side Resource Capacity in Nebraska through 2030



[88] Navigant compiled data pertaining Nebraska electric cooperative utilities by aggregating data from electric cooperative association instead of collecting data from individual cooperatives.

Table A-65. Projected Demand-Side Resource Annual Energy Impact in Nebraska through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	37	55	73	92	209	330	455
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	434	433	432	431	444	456	469
DG-Renewables	115	118	121	123	132	144	160
Smart Grid [a c]	0	0	0	0	5	10	15
TOTAL	586	606	626	646	789	940	1,100
Total Annual Electricity Consumption (AEC) [d]	30,657	30,395	31,531	29,959	30,657	31,269	31,880
% of AEC Supported by Demand-Side Resources	1.9%	2.0%	2.0%	2.2%	2.6%	3.0%	3.4%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-65. Projected Demand-Side Resource Annual Energy Impact in Nebraska through 2030

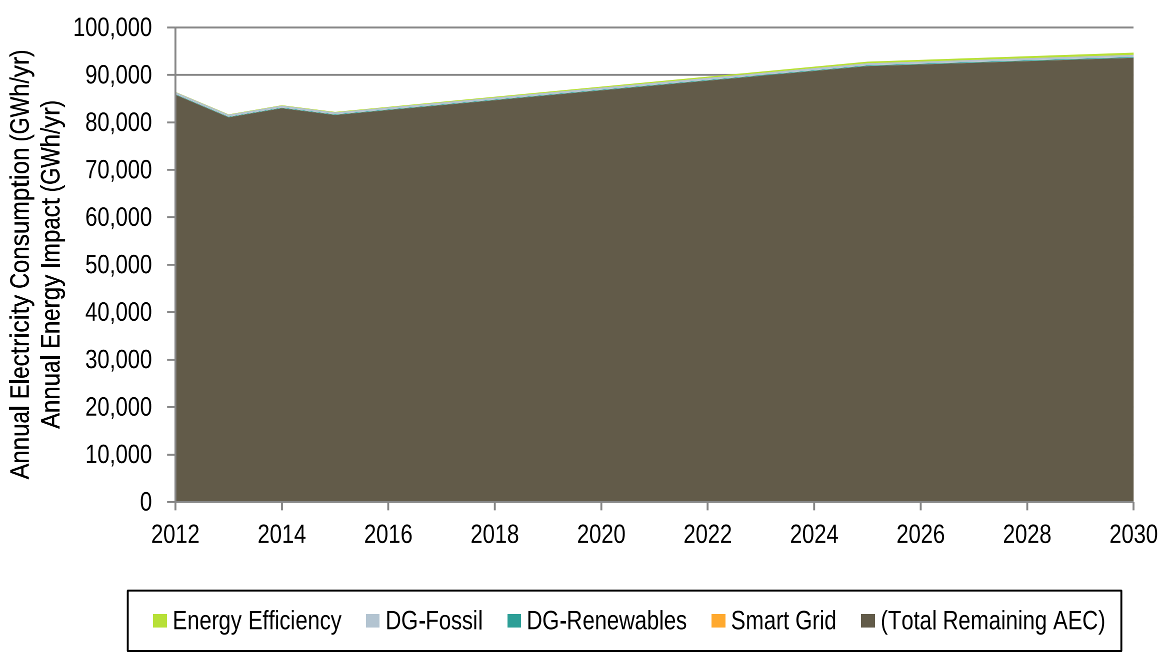
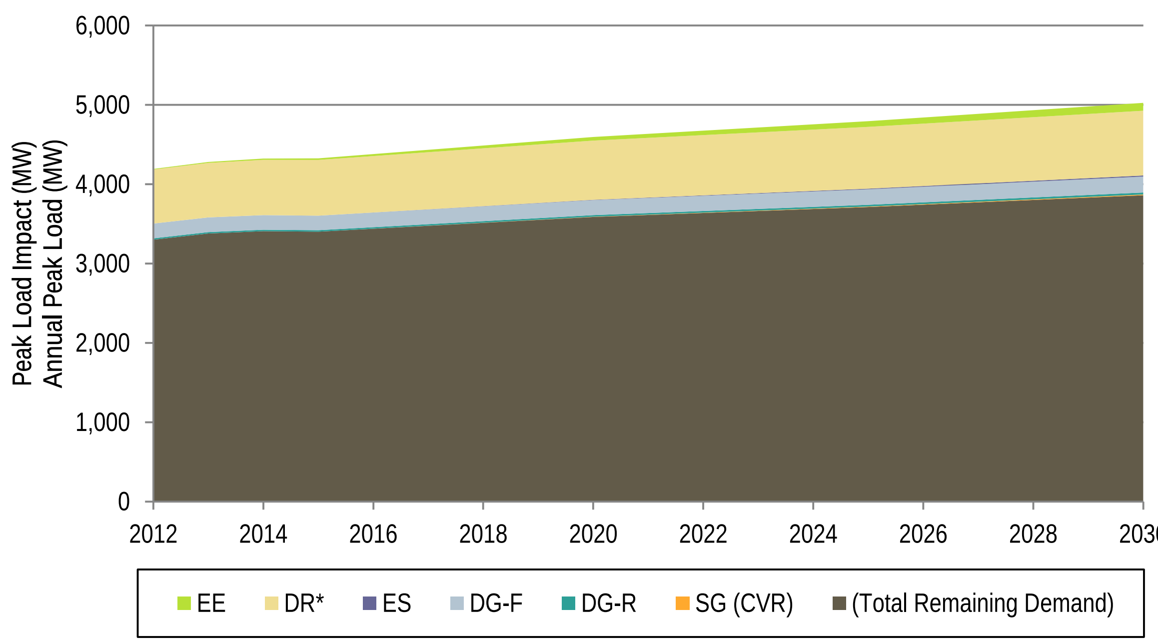


Table A-66. Projected Demand-Side Resource Peak Load Impact in Nebraska through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	8	12	16	20	45	72	99
Demand Response (conventional)	680	686	696	701	740	771	800
Demand Response (smart grid-enabled)*	1	1	1	1	6	8	16
Energy Storage	0	0	0	0	4	8	14
DG-Fossil	186	185	184	183	189	195	201
DG-Renewables	17	18	18	19	20	22	25
Smart Grid (CVR)	0	0	0	0	3	6	9
TOTAL	892	902	915	924	1,008	1,082	1,165
Total Annual Peak Load	4,192	4,280	4,323	4,325	4,595	4,794	5,025
% of Peak Load Supported by Demand-Side Resources	21.3%	21.1%	21.2%	21.4%	21.9%	22.6%	23.2%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-66. Projected Demand-Side Resource Peak Load Impact in Nebraska through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

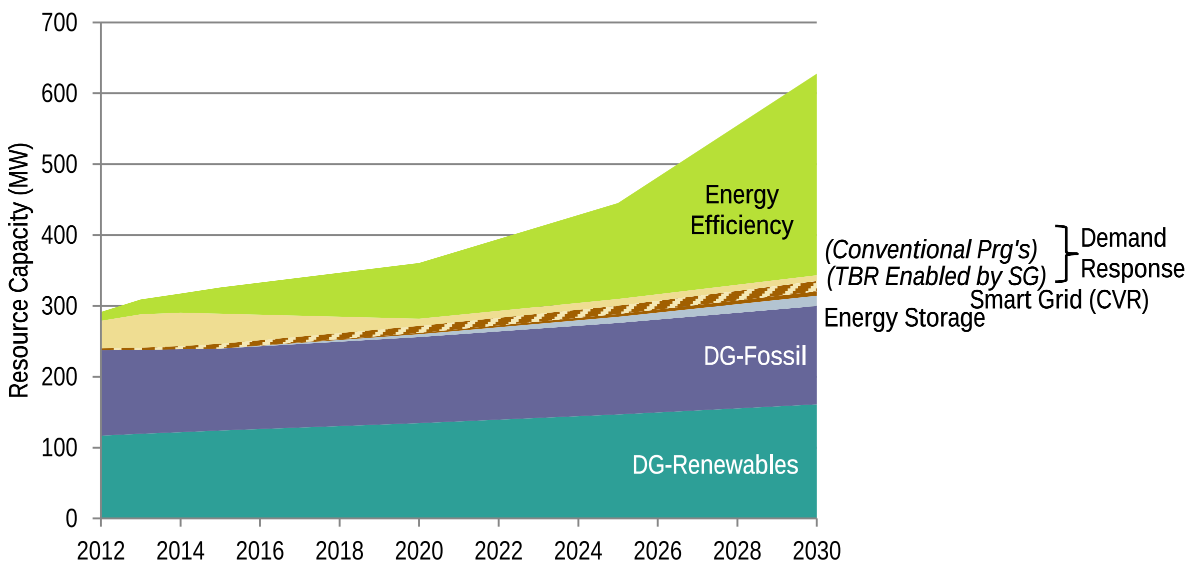
A.23 New Hampshire[89]

Table A-67. Projected Demand-Side Resource Capacity in New Hampshire through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	12	21	27	37	79	135	284
Demand Response (conventional)	39	47	47	43	10	10	8
Demand Response (smart grid-enabled)*	2	2	4	7	10	12	15
Energy Storage	0	0	0	0	4	9	15
DG-Fossil	121	119	117	116	121	129	139
DG-Renewables	117	119	122	124	135	147	161
Smart Grid (CVR)	0	0	0	0	2	4	6
TOTAL	291	309	317	326	361	445	628

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-67. Projected Demand-Side Resource Capacity in New Hampshire through 2030



[89] EE and DR forecasts are based on ISO-NE's 2012 Forecast Data File. The near-term Demand Response forecasts for New England states are based on the Real-Time Demand Response cleared in the primary Forward Capacity Auctions for ISO-NE, which show a significant decrease in committed DR capacity (approximately 1400 MW in 2015 to less than 900 MW in 2016). While this may be due to characteristics specific to New England's market, it is too soon to know whether increased availability of smart grid-enabled time-based rate programs in the area may influence the market trend. Navigant scaled back the forecast of New Hampshire's smart grid-enabled time-based rate programs in order to maintain consistency with the forecast for overall DR resource capacity. This assessment assumes that the overall DR capacity committed in 2016 grows gradually from 2016 through 2030.

Table A-68. Projected Demand-Side Resource Annual Energy Impact in New Hampshire through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	81	136	175	240	510	878	1,845
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	133	129	126	122	145	173	205
DG-Renewables	581	593	602	612	649	698	760
Smart Grid [a c]	0	0	0	0	2	4	5
TOTAL	795	858	902	974	1,306	1,752	2,815
Total Annual Electricity Consumption (AEC) [d]	10,963	11,058	11,152	11,058	11,341	11,625	11,530
% of AEC Supported by Demand-Side Resources	7.3%	7.8%	8.1%	8.8%	11.5%	15.1%	24.4%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-68. Projected Demand-Side Resource Annual Energy Impact in New Hampshire through 2030

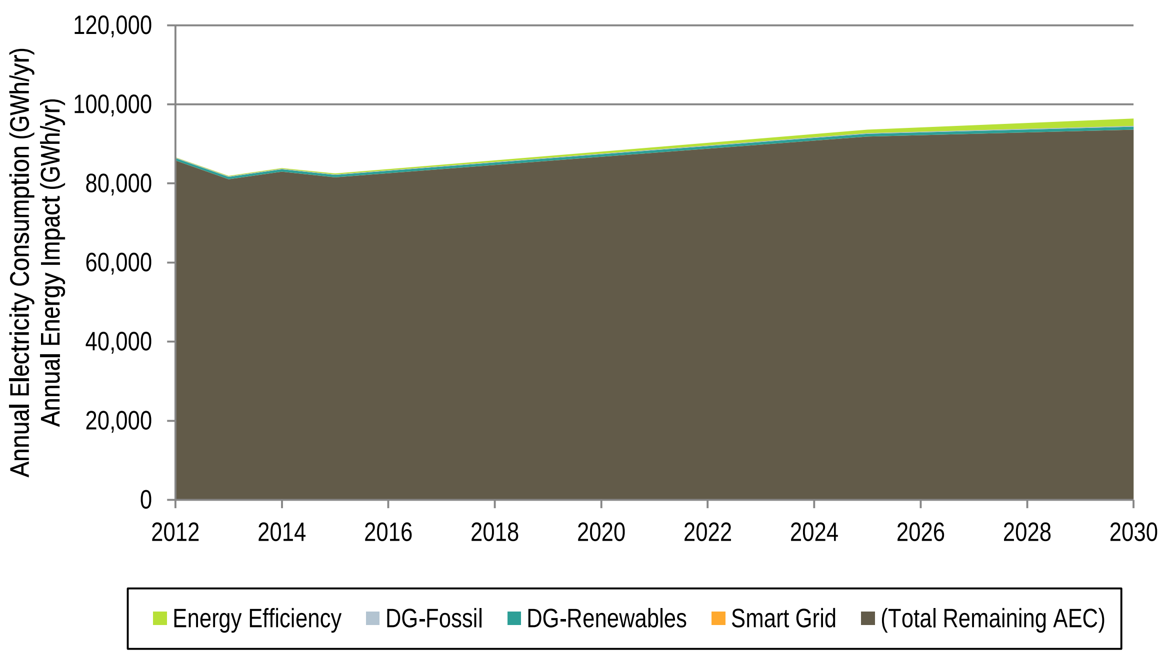


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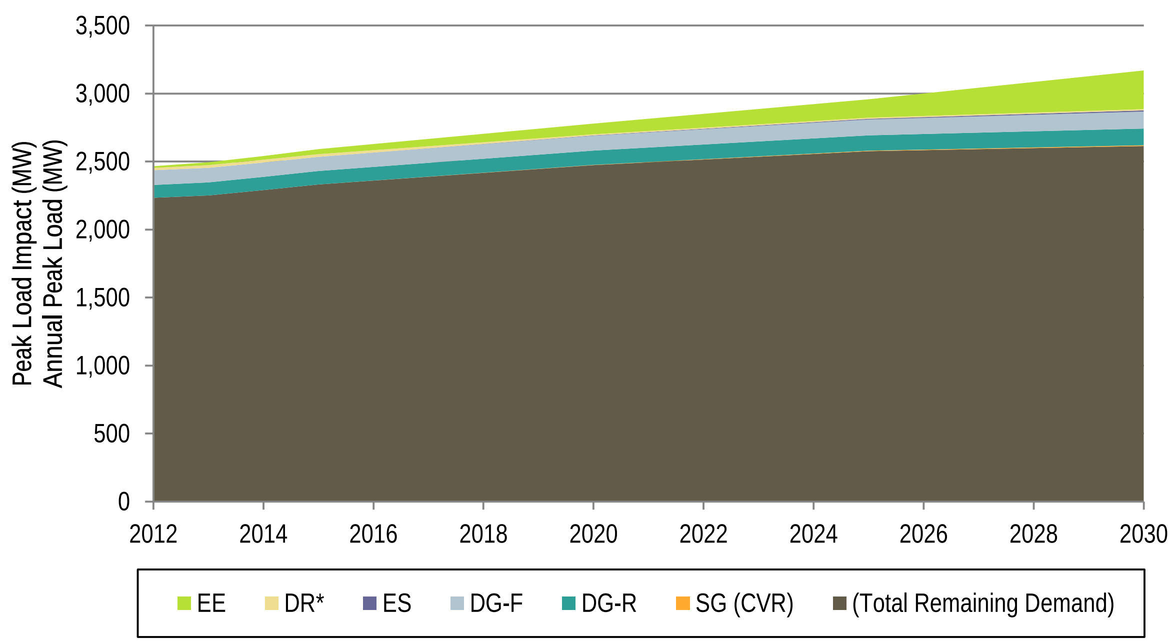
Table A-69. Projected Demand-Side Resource Peak Load Impact in New Hampshire through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	12	21	27	37	79	135	284
Demand Response (conventional)	15	19	19	17	4	3	3
Demand Response (smart grid-enabled)*	1	1	2	3	4	5	7
Energy Storage	0	0	0	0	2	5	9
DG-Fossil	109	107	106	104	109	116	125
DG-Renewables	94	96	97	99	105	113	123
Smart Grid (CVR)	0	0	0	0	2	4	6
TOTAL	232	244	250	260	305	382	556
Total Annual Peak Load	2,465	2,494	2,540	2,591	2,779	2,958	3,169
% of Peak Load Supported by Demand-Side Resources	9.4%	9.8%	9.9%	10.0%	11.0%	12.9%	17.5%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-69. Projected Demand-Side Resource Peak Load Impact in New Hampshire through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

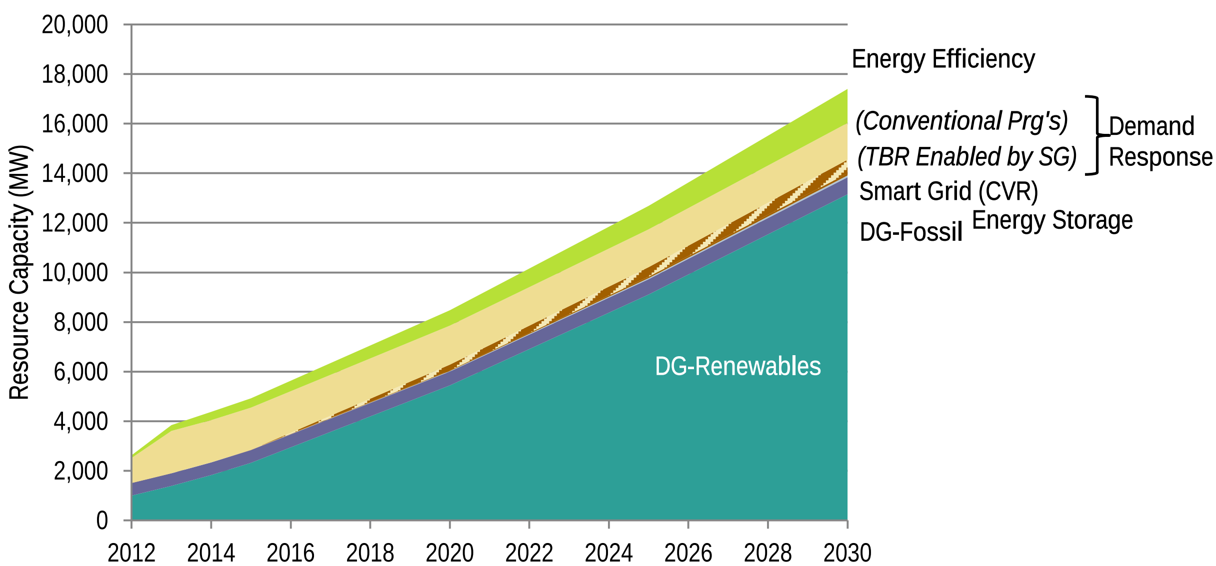
A.24 New Jersey[90]

Table A-70. Projected Demand-Side Resource Capacity in New Jersey through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	111	236	335	375	620	947	1,373
Demand Response (conventional)	1,009	1,707	1,702	1,702	1,573	1,526	1,480
Demand Response (smart grid-enabled)*	0	0	0	0	230	384	552
Energy Storage	2	2	2	2	21	45	74
DG-Fossil	507	509	511	513	560	616	685
DG-Renewables	1,003	1,392	1,830	2,323	5,445	9,111	13,151
Smart Grid (CVR)	0	0	0	8	27	57	84
TOTAL	2,632	3,845	4,379	4,925	8,475	12,686	17,399

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-70. Projected Demand-Side Resource Capacity in New Jersey through 2030



[90] Navigant based EE forecast in 2013 and onward on: "Management Consulting: Program Administrator – New Jersey Clean Energy Program," RFP #2013-X-22546, August 15, 2012, p.312-316. Phone correspondance with Mona Mosser, Board of Public Utilities, New Jersey, December 2012. Furthermore, Navigant based on the 2012 EE estimate on the average between the 2013 EE from the source noted above and the 2011 EE reported for the 2001-2011 NJ Clean Energy Program.

Table A-71. Projected Demand-Side Resource Annual Energy Impact in New Jersey through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	512	1,082	1,539	1,723	2,848	4,348	6,307
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	812	826	840	855	980	1,125	1,292
DG-Renewables	1,662	2,113	2,610	3,173	6,674	10,796	15,363
Smart Grid [a c]	0	0	0	5	24	53	108
TOTAL	2,986	4,021	4,989	5,756	10,525	16,322	23,070
Total Annual Electricity Consumption (AEC) [d]	77,042	75,375	75,746	75,375	74,634	75,375	77,412
% of AEC Supported by Demand-Side Resources	3.9%	5.3%	6.6%	7.6%	14.1%	21.7%	29.8%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-71. Projected Demand-Side Resource Annual Energy Impact in New Jersey through 2030

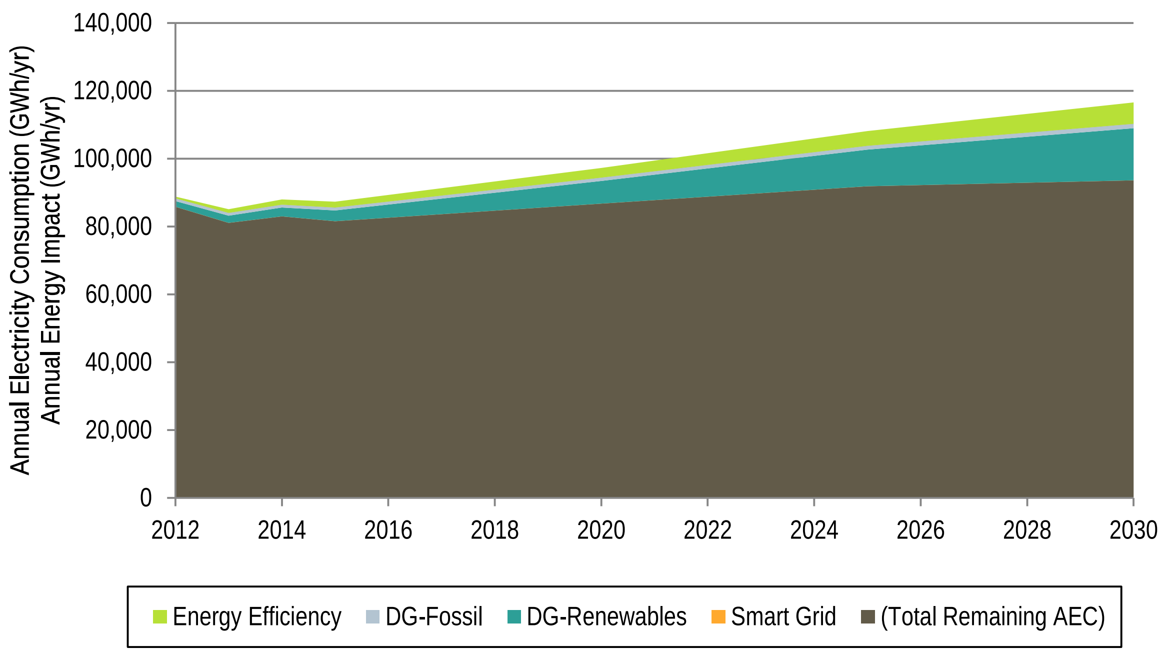


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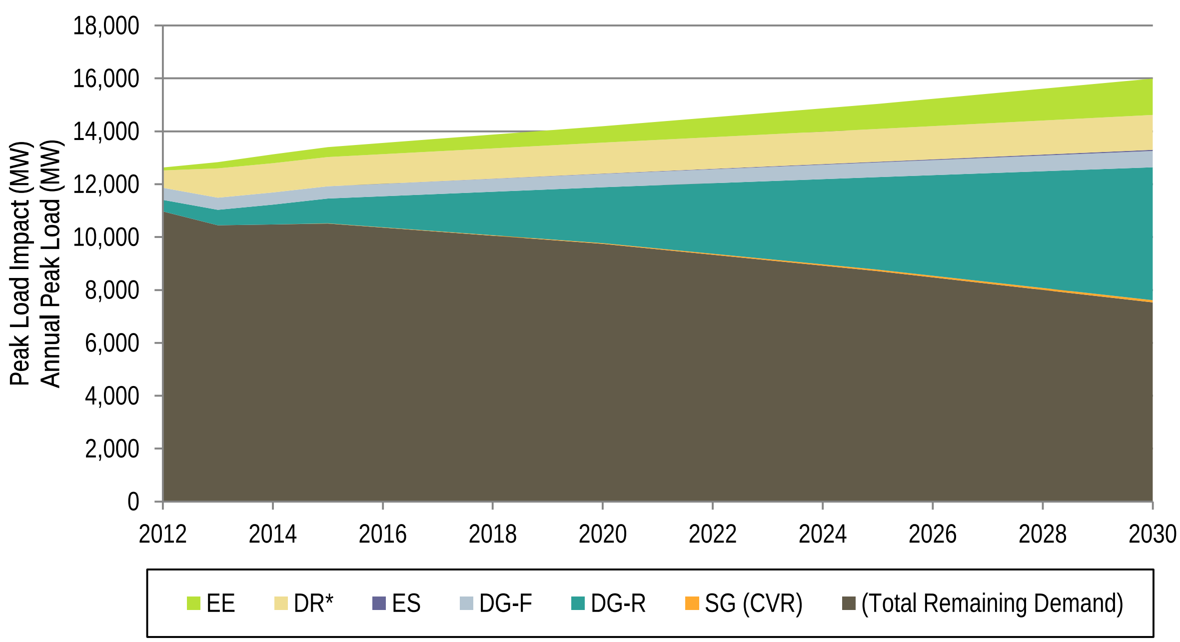
Table A-72. Projected Demand-Side Resource Peak Load Impact in New Jersey through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	111	236	335	375	620	947	1,373
Demand Response (conventional)	655	1,109	1,106	1,106	1,067	1,068	1,071
Demand Response (smart grid-enabled)*	0	0	0	0	104	173	248
Energy Storage	0	0	0	0	12	26	44
DG-Fossil	456	458	460	462	504	555	616
DG-Renewables	436	585	750	938	2,114	3,498	5,025
Smart Grid (CVR)	0	0	0	8	27	57	84
TOTAL	1,660	2,387	2,651	2,889	4,448	6,323	8,462
Total Annual Peak Load	12,630	12,833	13,128	13,401	14,191	15,035	15,992
% of Peak Load Supported by Demand-Side Resources	13.1%	18.6%	20.2%	21.6%	31.3%	42.1%	52.9%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-72. Projected Demand-Side Resource Peak Load Impact in New Jersey through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

A.25 New Mexico[91]

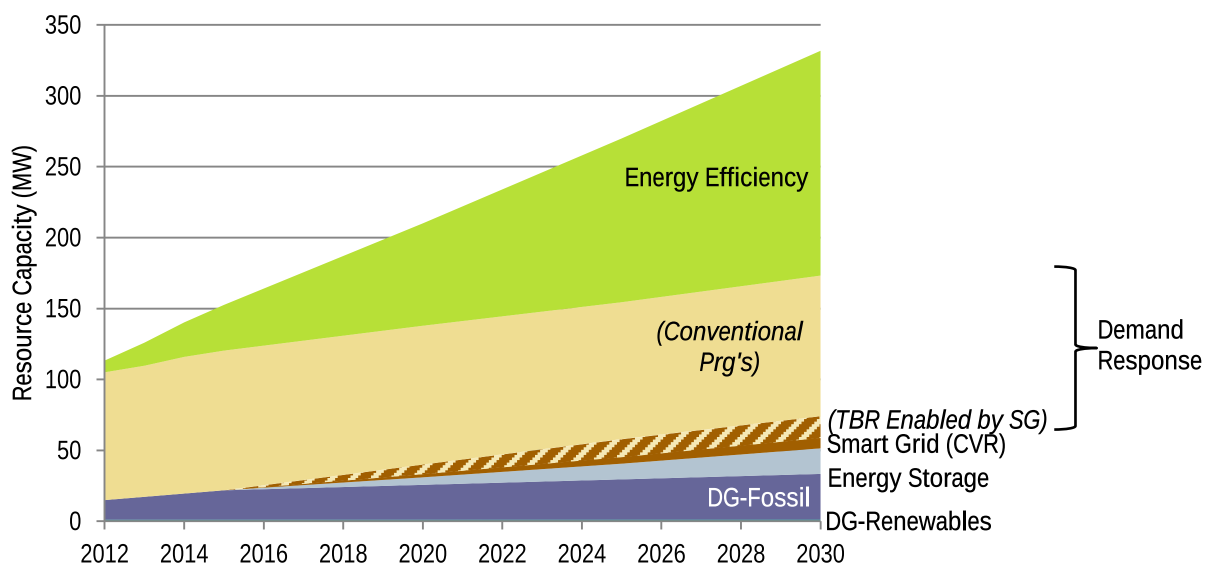
Note that the data in this section covers only the parts of New Mexico that are served by utilities within the Eastern Interconnection.

Table A-73. Projected Demand-Side Resource Capacity in New Mexico through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	8	16	24	32	72	115	158
Demand Response (conventional)	90	92	96	98	98	96	99
Demand Response (smart grid-enabled)*	0	0	0	0	7	13	15
Energy Storage	0	0	0	0	5	11	18
DG-Fossil	14	16	18	21	25	28	32
DG-Renewables	1	1	1	1	1	1	1
Smart Grid (CVR)	0	0	0	0	2	5	7
TOTAL	113	126	140	153	210	270	332

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-73. Projected Demand-Side Resource Capacity in New Mexico through 2030



[91] The forecast for New Mexico assumes that the 2012 EE data available for Southwestern Public Service Company is cumulative. Navigant used 2011 EIA-861 data to estimate the incremental annual savings achieved in 2012.

Table A-74. Projected Demand-Side Resource Annual Energy Impact in New Mexico through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	38	75	112	148	331	530	727
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	30	35	40	45	54	62	71
DG-Renewables	2	2	2	3	3	3	3
Smart Grid [a c]	0	0	0	0	1	2	3
TOTAL	71	112	154	196	388	597	804
Total Annual Electricity Consumption (AEC) [d]	6,644	6,401	6,489	6,567	6,743	6,997	7,107
% of AEC Supported by Demand-Side Resources	1.1%	1.8%	2.4%	3.0%	5.8%	8.5%	11.3%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-74. Projected Demand-Side Resource Annual Energy Impact in New Mexico through 2030

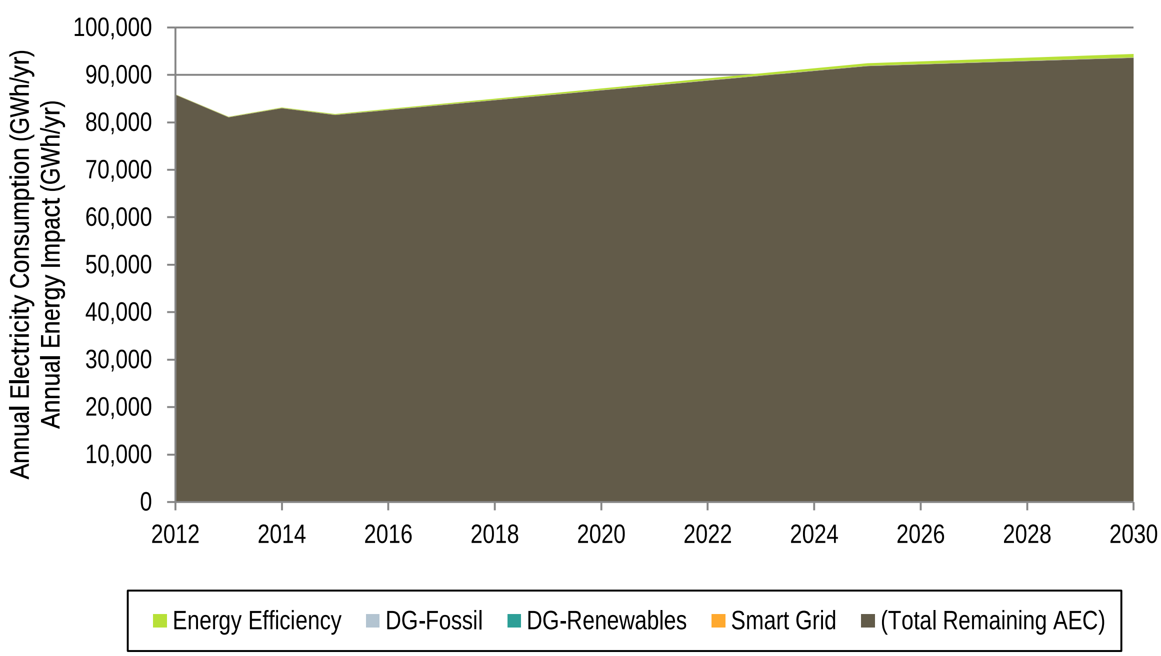
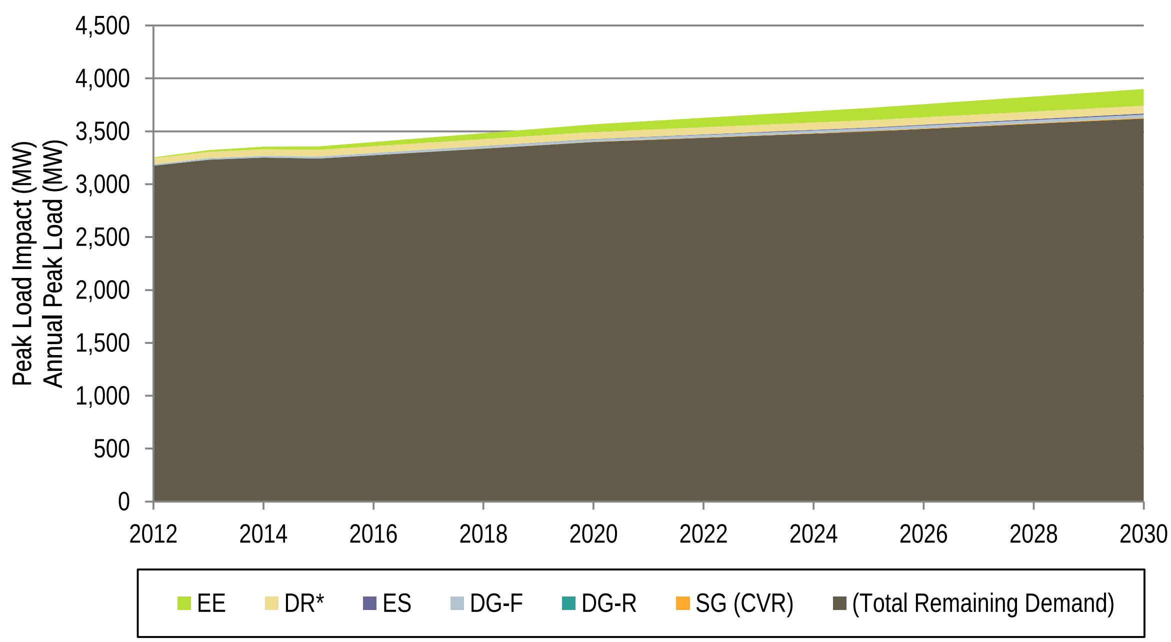


Table A-75. Projected Demand-Side Resource Peak Load Impact in New Mexico through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	8	16	24	32	72	115	158
Demand Response (conventional)	58	59	62	63	64	64	66
Demand Response (smart grid-enabled)*	0	0	0	0	3	6	7
Energy Storage	0	0	0	0	3	7	11
DG-Fossil	12	14	17	19	22	26	29
DG-Renewables	1	1	1	1	1	1	1
Smart Grid (CVR)	0	0	0	0	2	5	7
TOTAL	79	90	103	114	167	222	279
Total Annual Peak Load	3,253	3,321	3,355	3,357	3,566	3,720	3,900
% of Peak Load Supported by Demand-Side Resources	2.4%	2.7%	3.1%	3.4%	4.7%	6.0%	7.2%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-75. Projected Demand-Side Resource Peak Load Impact in New Mexico through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

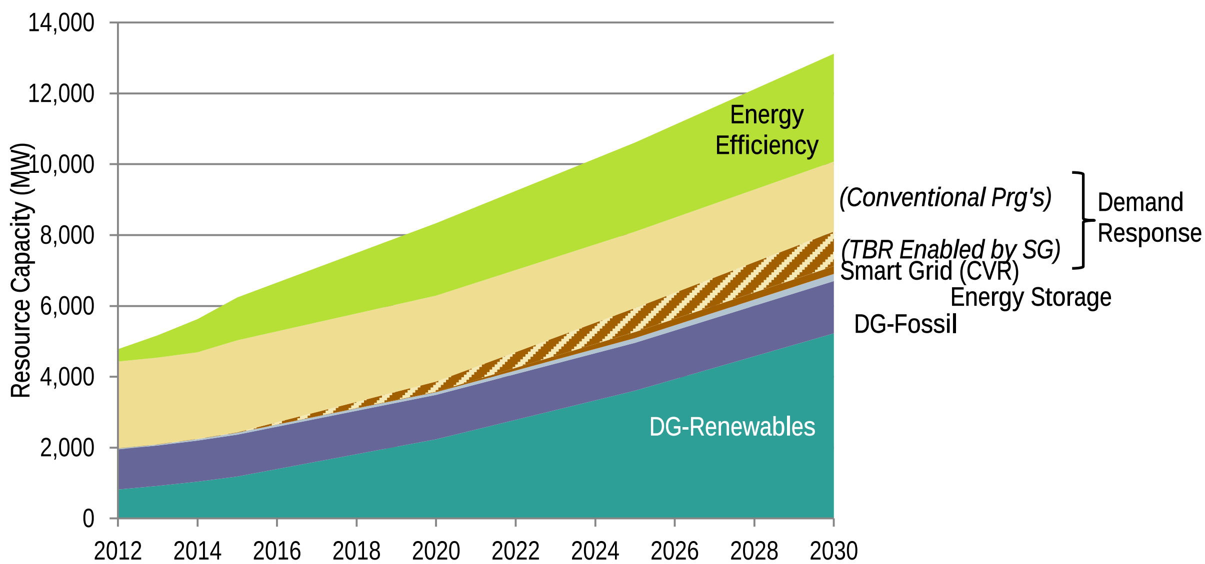
A.26 New York[92]

Table A-76. Projected Demand-Side Resource Capacity in New York through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	349	630	936	1,210	2,045	2,515	3,044
Demand Response (conventional)	2,448	2,446	2,444	2,597	2,427	2,156	1,973
Demand Response (smart grid-enabled)*	1	3	5	7	282	676	979
Energy Storage	29	29	41	55	75	133	201
DG-Fossil	1,133	1,142	1,160	1,182	1,254	1,351	1,476
DG-Renewables	818	920	1,040	1,184	2,236	3,607	5,225
Smart Grid (CVR)	0	0	1	4	16	172	219
TOTAL	4,779	5,171	5,627	6,239	8,335	10,611	13,117

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-76. Projected Demand-Side Resource Capacity in New York through 2030



[92] EE and DR forecast are based on NYISO's 2012 Load & Capacity Data, as well as a limited number of FERC DR survey responses for respondents reporting more potential peak reduction than what they enrolled in the ISO/RTO program.

Table A-77. Projected Demand-Side Resource Annual Energy Impact in New York through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	1,919	3,462	5,140	6,645	11,230	13,813	16,716
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	1,668	1,653	1,672	1,710	1,864	2,052	2,280
DG-Renewables	3,273	3,384	3,499	3,637	4,540	5,725	7,139
Smart Grid [a c]	0	0	7	7	36	183	238
TOTAL	6,860	8,499	10,318	11,999	17,669	21,773	26,372
Total Annual Electricity Consumption (AEC) [d]	144,387	141,263	141,957	141,263	139,875	141,263	145,081
% of AEC Supported by Demand-Side Resources	4.8%	6.0%	7.3%	8.5%	12.6%	15.4%	18.2%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-77. Projected Demand-Side Resource Annual Energy Impact in New York through 2030

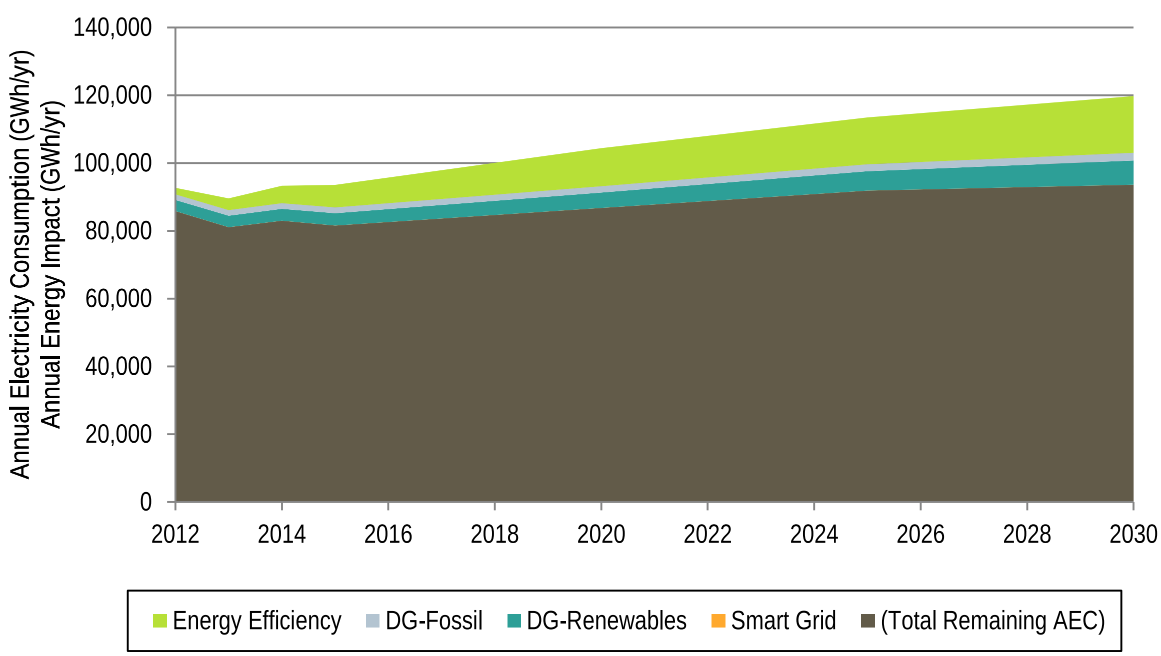
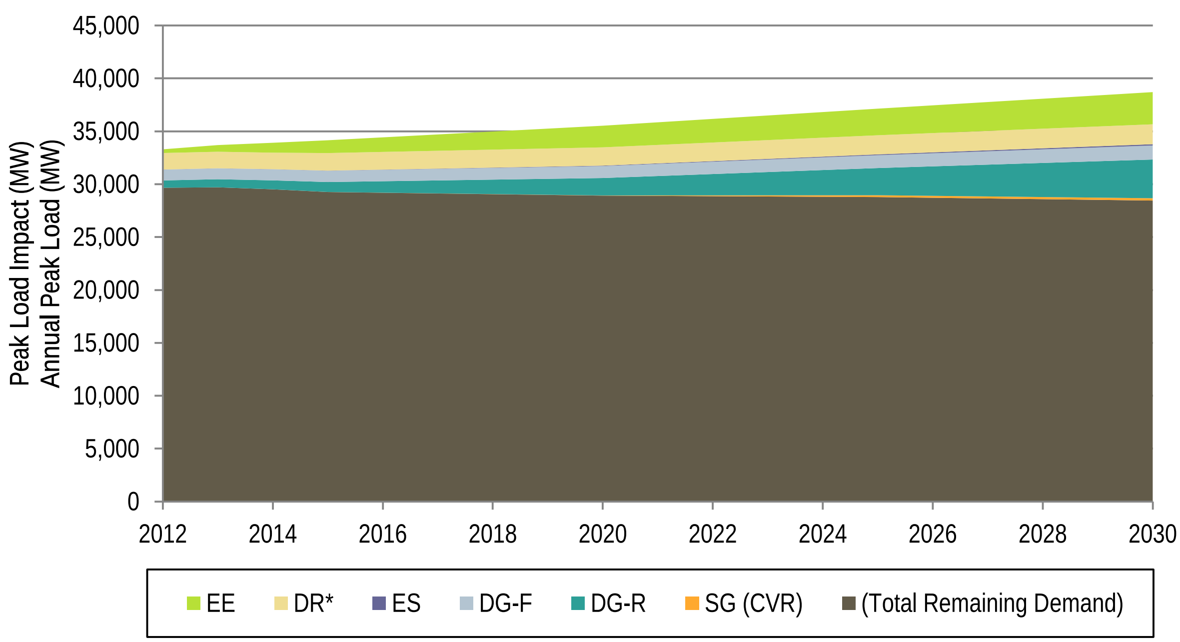


Table A-78. Projected Demand-Side Resource Peak Load Impact in New York through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	349	630	936	1,210	2,045	2,515	3,044
Demand Response (conventional)	1,562	1,561	1,560	1,658	1,602	1,503	1,443
Demand Response (smart grid-enabled)*	1	1	2	3	127	304	440
Energy Storage	8	8	11	12	42	76	118
DG-Fossil	1,020	1,028	1,044	1,064	1,129	1,216	1,329
DG-Renewables	693	763	844	942	1,649	2,571	3,660
Smart Grid (CVR)	0	0	1	4	16	172	219
TOTAL	3,634	3,992	4,399	4,893	6,609	8,358	10,252
Total Annual Peak Load	33,295	33,696	33,914	34,151	35,526	37,139	38,704
% of Peak Load Supported by Demand-Side Resources	10.9%	11.8%	13.0%	14.3%	18.6%	22.5%	26.5%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-78. Projected Demand-Side Resource Peak Load Impact in New York through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

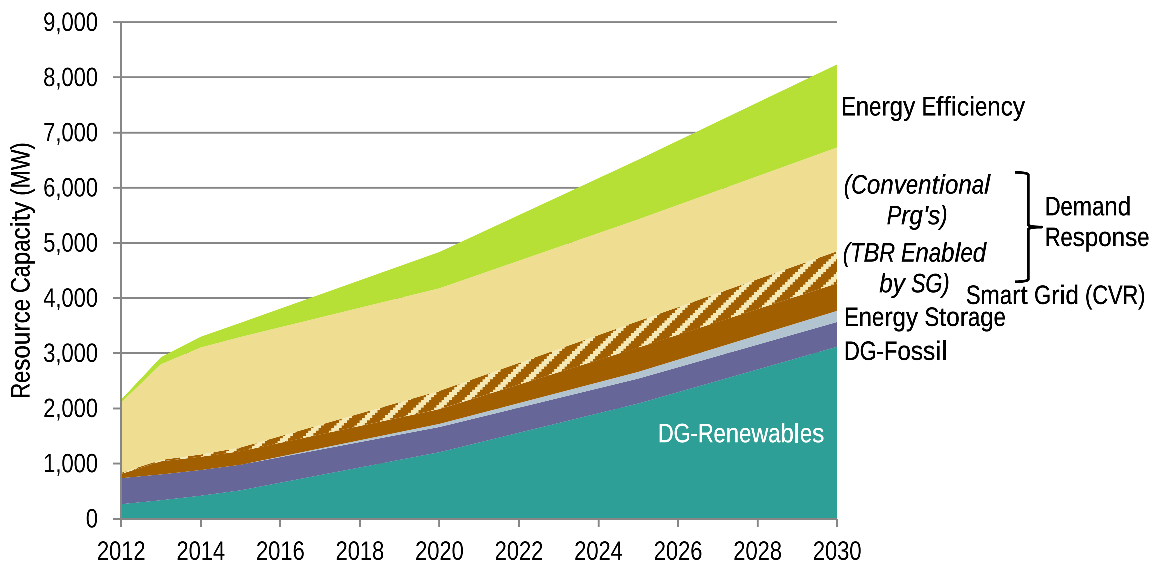
A.27 North Carolina[93]

Table A-79. Projected Demand-Side Resource Capacity in North Carolina through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	54	127	194	256	658	1,080	1,504
Demand Response (conventional)	1,275	1,739	1,940	2,006	1,863	1,847	1,882
Demand Response (smart grid-enabled)*	21	24	42	67	330	479	584
Energy Storage	1	1	1	1	58	124	204
DG-Fossil	471	467	465	463	456	450	447
DG-Renewables	265	336	418	516	1,206	2,089	3,119
Smart Grid (CVR)	75	236	240	244	265	439	496
TOTAL	2,162	2,929	3,300	3,552	4,836	6,509	8,236

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-79. Projected Demand-Side Resource Capacity in North Carolina through 2030



[93] The forecast for North Carolina assumes that the 2012 EE data available for Progress Energy Carolinas and Virginia Electric and Power Company are cumulative. Navigant used 2011 EIA-861 data to estimate the incremental annual savings achieved in 2012. Furthermore, Navigant compiled data pertaining North Carolina electric cooperative utilities by aggregating data from electric cooperative association instead of collecting data from individual cooperatives.

Table A-80. Projected Demand-Side Resource Annual Energy Impact in North Carolina through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	383	898	1,376	1,816	4,660	7,651	10,656
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	818	811	808	806	778	754	733
DG-Renewables	897	1,004	1,122	1,262	2,209	3,422	4,848
Smart Grid [a c]	16	50	50	51	55	211	268
TOTAL	2,113	2,762	3,356	3,934	7,702	12,037	16,504
Total Annual Electricity Consumption (AEC) [d]	131,266	129,638	131,266	128,011	142,476	149,346	152,782
% of AEC Supported by Demand-Side Resources	1.6%	2.1%	2.6%	3.1%	5.4%	8.1%	10.8%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-80. Projected Demand-Side Resource Annual Energy Impact in North Carolina through 2030

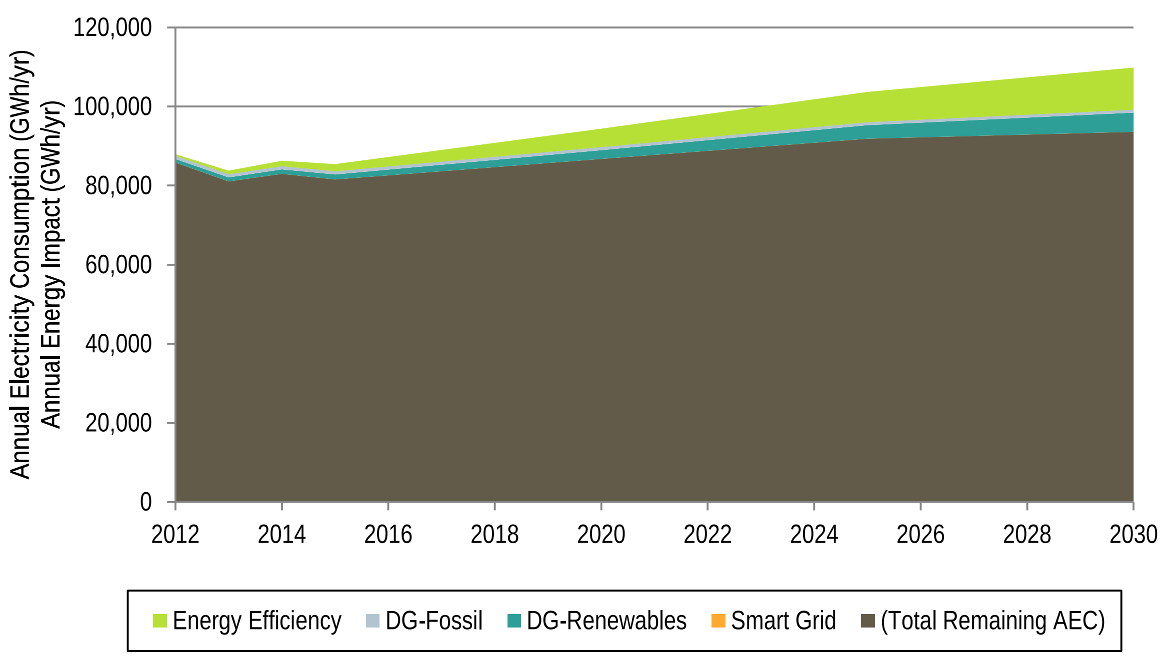
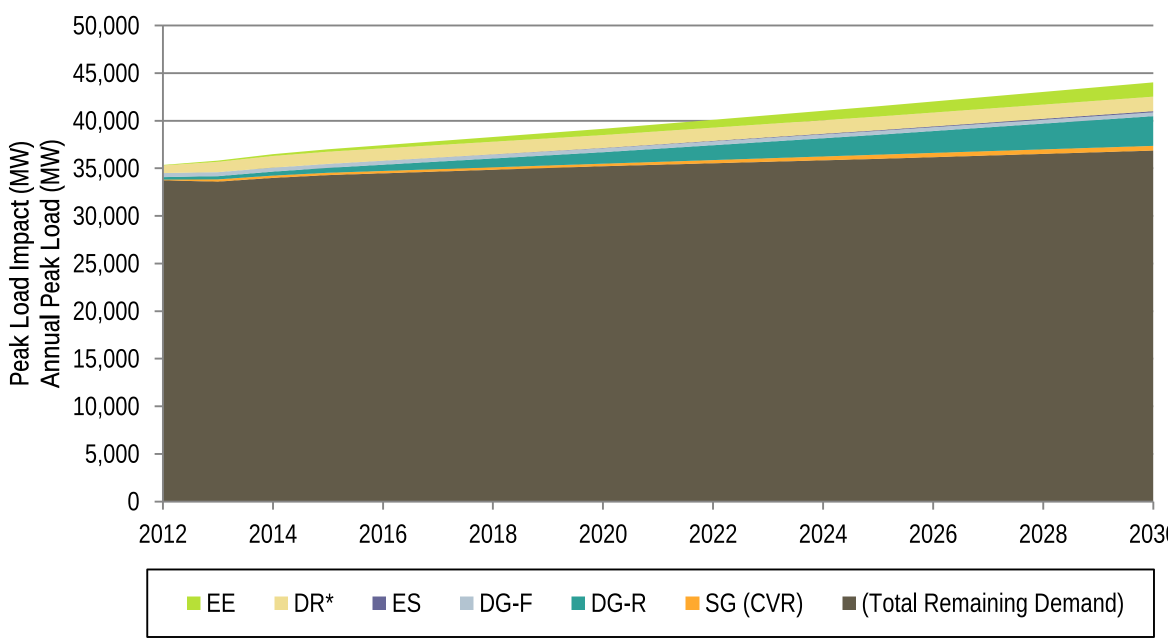


Table A-81. Projected Demand-Side Resource Peak Load Impact in North Carolina through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	54	127	194	256	658	1,080	1,504
Demand Response (conventional)	791	1,079	1,206	1,251	1,207	1,222	1,261
Demand Response (smart grid-enabled)*	9	11	19	30	148	215	263
Energy Storage	1	1	1	1	34	73	121
DG-Fossil	424	421	419	417	410	405	402
DG-Renewables	265	336	418	516	1,206	2,089	3,119
Smart Grid (CVR)	75	236	240	244	265	439	496
TOTAL	1,620	2,209	2,496	2,714	3,929	5,524	7,167
Total Annual Peak Load	35,354	35,810	36,487	36,999	39,148	41,517	44,027
% of Peak Load Supported by Demand-Side Resources	4.6%	6.2%	6.8%	7.3%	10.0%	13.3%	16.3%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-81. Projected Demand-Side Resource Peak Load Impact in North Carolina through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

A.28 North Dakota

Table A-82. Projected Demand-Side Resource Capacity in North Dakota through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	1	2	4	5	13	20	29
Demand Response (conventional)	319	358	410	431	448	468	486
Demand Response (smart grid-enabled)*	0	0	0	0	5	8	14
Energy Storage	0	0	0	0	11	23	38
DG-Fossil	39	39	40	40	40	41	42
DG-Renewables	23	23	24	24	25	27	30
Smart Grid (CVR)	0	0	0	0	5	10	16
TOTAL	381	423	476	501	547	598	654

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-82. Projected Demand-Side Resource Capacity in North Dakota through 2030

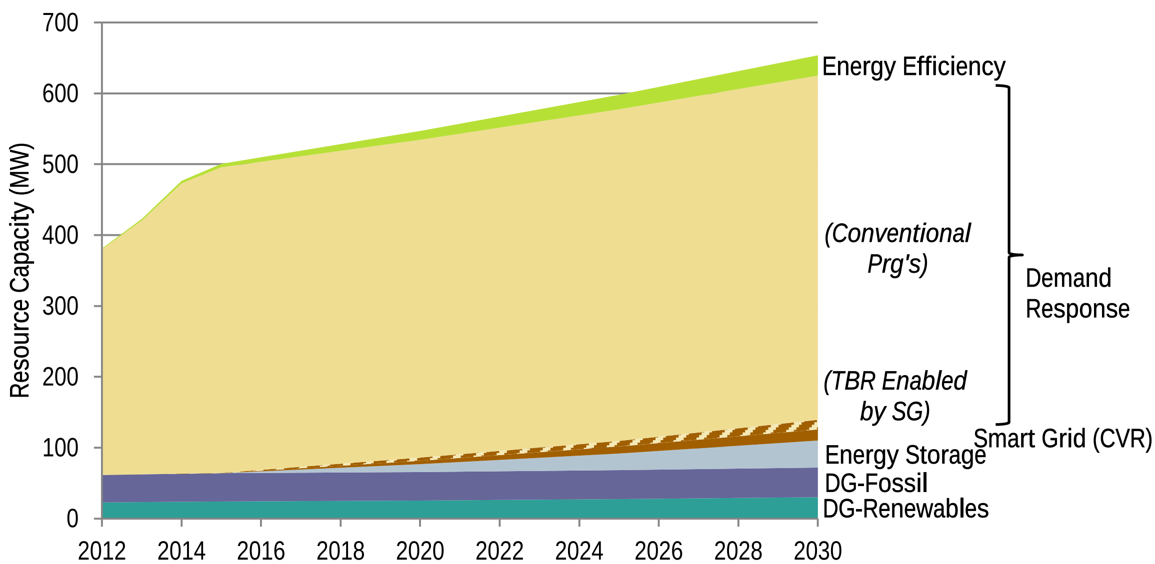


Table A-83. Projected Demand-Side Resource Annual Energy Impact in North Dakota through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	11	24	36	50	127	208	291
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	101	105	110	114	121	129	137
DG-Renewables	99	102	104	107	114	125	140
Smart Grid [a c]	0	0	0	0	2	4	6
TOTAL	212	231	250	270	364	465	574
Total Annual Electricity Consumption (AEC) [d]	11,803	11,703	12,140	11,534	11,803	12,039	12,274
% of AEC Supported by Demand-Side Resources	1.8%	2.0%	2.1%	2.3%	3.1%	3.9%	4.7%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-83. Projected Demand-Side Resource Annual Energy Impact in North Dakota through 2030

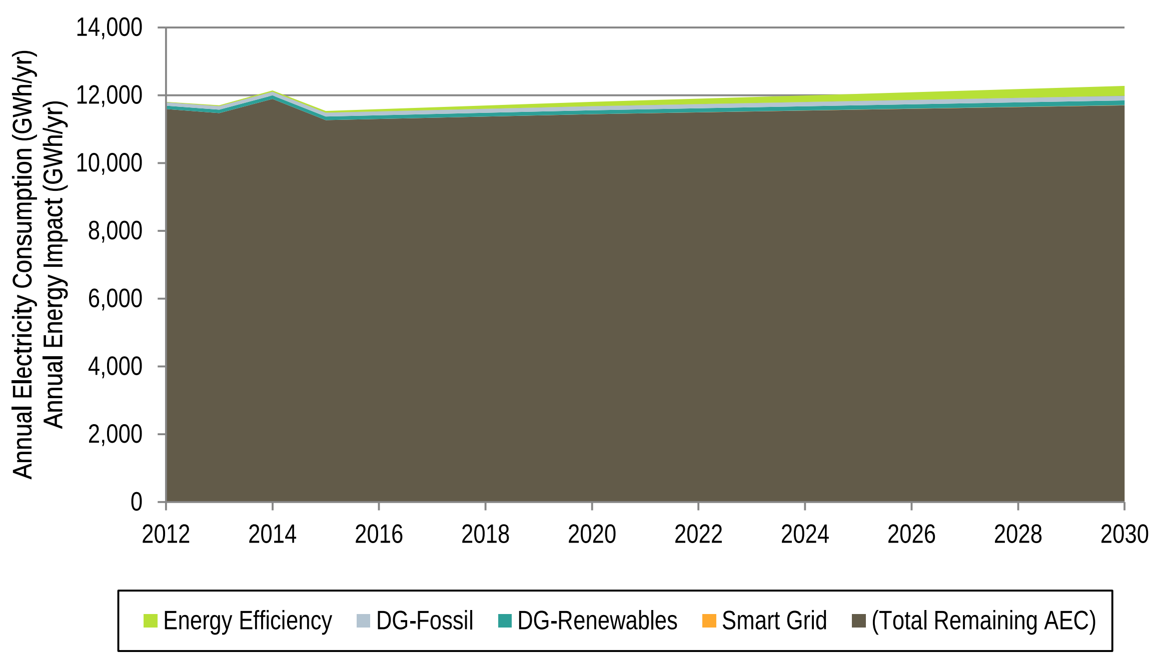
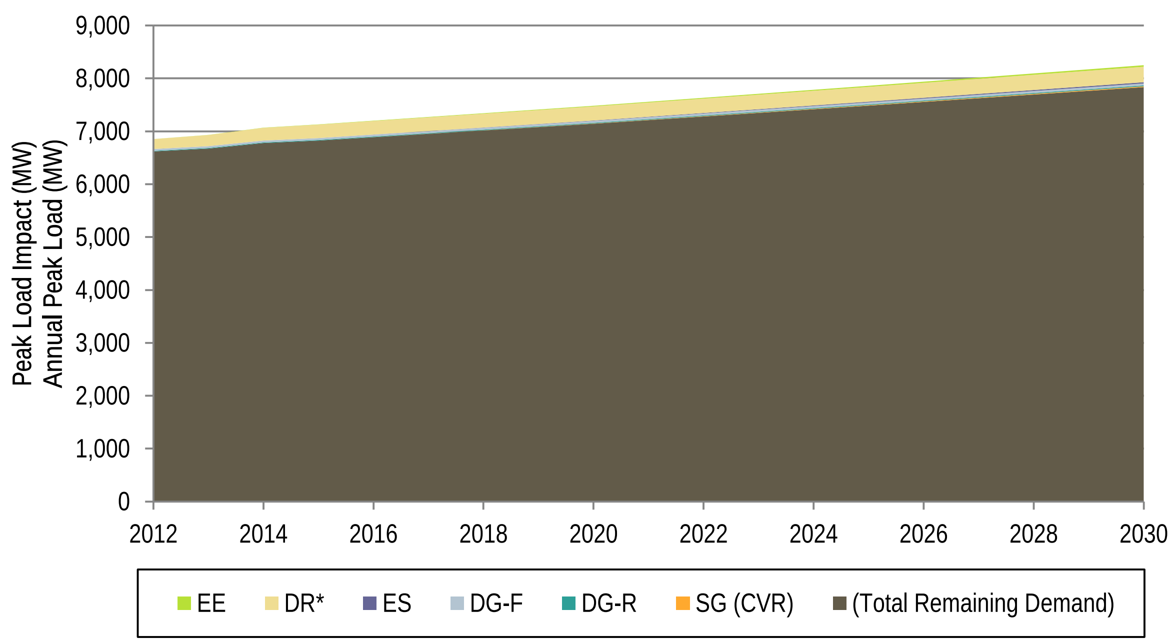


Table A-84. Projected Demand-Side Resource Peak Load Impact in North Dakota through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	1	2	4	5	13	20	29
Demand Response (conventional)	187	210	241	253	264	276	287
Demand Response (smart grid-enabled)*	0	0	0	0	2	4	6
Energy Storage	0	0	0	0	7	14	23
DG-Fossil	35	35	36	36	36	37	38
DG-Renewables	11	11	12	12	13	15	17
Smart Grid (CVR)	0	0	0	0	5	10	16
TOTAL	234	259	291	306	339	375	415
Total Annual Peak Load	6,853	6,932	7,069	7,130	7,482	7,860	8,249
% of Peak Load Supported by Demand-Side Resources	3.4%	3.7%	4.1%	4.3%	4.5%	4.8%	5.0%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-84. Projected Demand-Side Resource Peak Load Impact in North Dakota through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

A.29 Ohio

Table A-85. Projected Demand-Side Resource Capacity in Ohio through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	220	466	739	1,054	2,194	3,246	3,930
Demand Response (conventional)	1,571	1,434	2,577	2,569	2,466	2,529	2,621
Demand Response (smart grid-enabled)*	5	11	16	28	284	384	477
Energy Storage	2	3	3	3	46	94	153
DG-Fossil	984	955	927	900	921	977	1,044
DG-Renewables	105	120	136	154	260	384	523
Smart Grid (CVR)	0	0	9	19	46	174	216
TOTAL	2,888	2,989	4,407	4,726	6,217	7,789	8,964

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-85. Projected Demand-Side Resource Capacity in Ohio through 2030

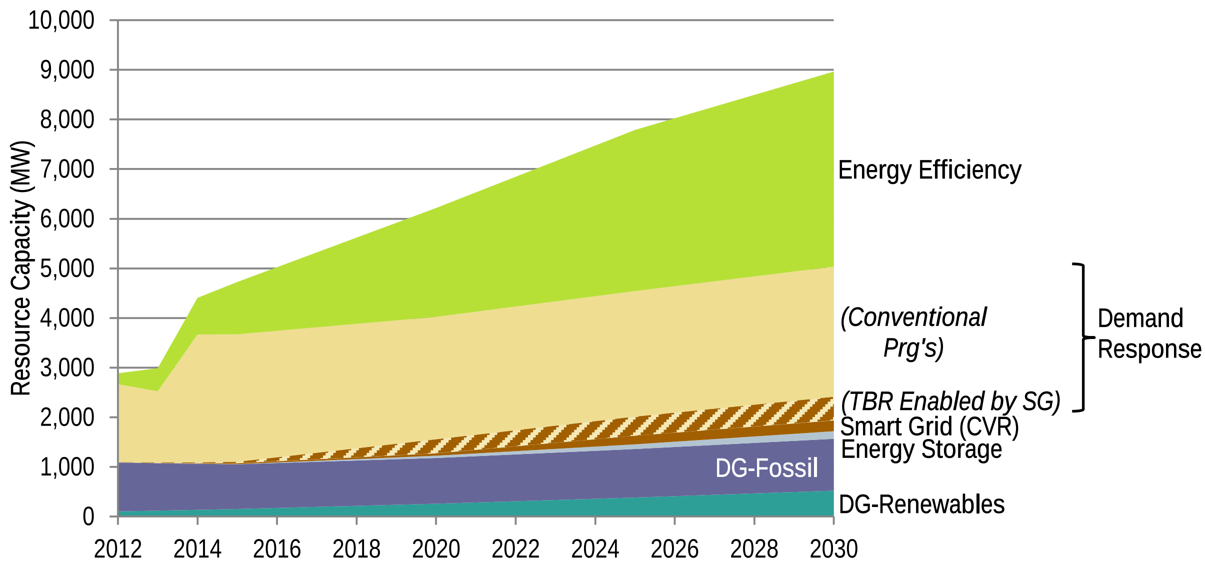


Table A-86. Projected Demand-Side Resource Annual Energy Impact in Ohio through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	1,090	2,311	3,662	5,227	10,877	16,093	19,484
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	2,019	1,919	1,820	1,720	1,714	1,849	2,019
DG-Renewables	399	425	450	478	625	804	1,010
Smart Grid [a c]	0	0	46	94	230	379	439
TOTAL	3,508	4,655	5,977	7,519	13,446	19,125	22,952
Total Annual Electricity Consumption (AEC) [d]	135,265	139,028	127,295	135,486	134,822	144,784	149,876
% of AEC Supported by Demand-Side Resources	2.6%	3.3%	4.7%	5.5%	10.0%	13.2%	15.3%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-86. Projected Demand-Side Resource Annual Energy Impact in Ohio through 2030

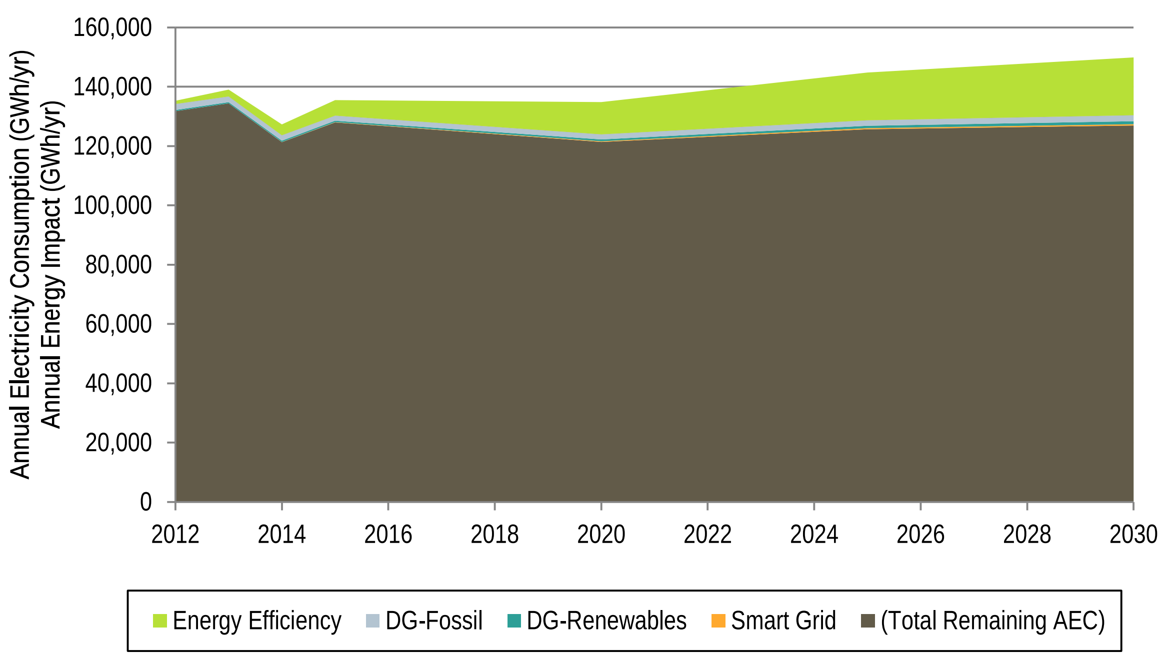


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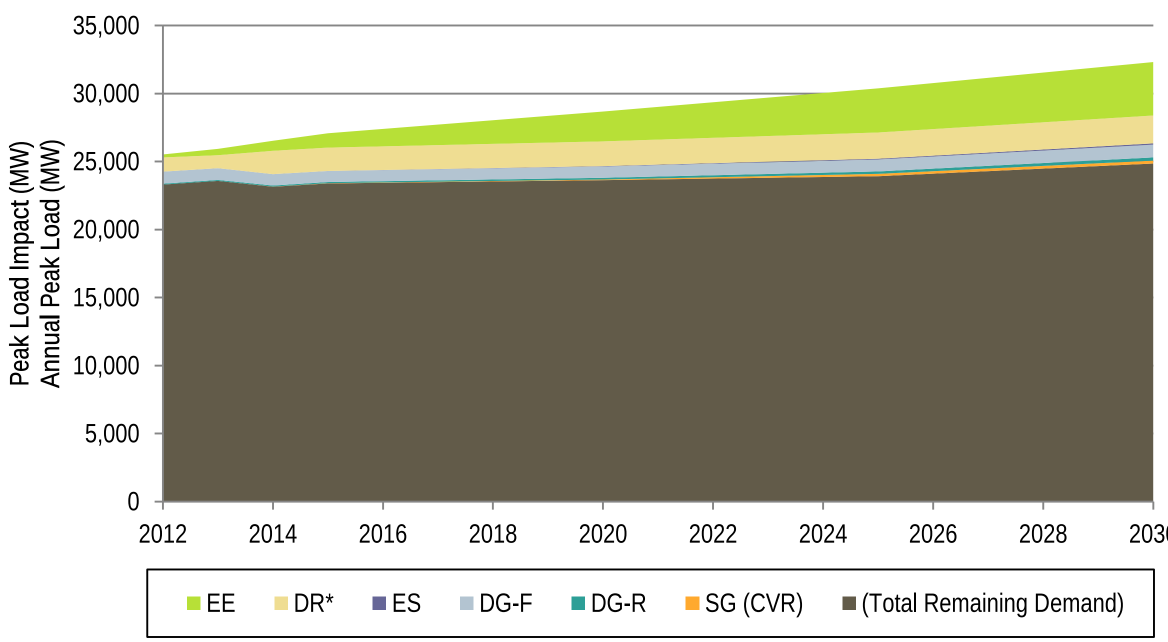
Table A-87. Projected Demand-Side Resource Peak Load Impact in Ohio through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	220	466	739	1,054	2,194	3,246	3,930
Demand Response (conventional)	1,041	951	1,709	1,706	1,692	1,756	1,836
Demand Response (smart grid-enabled)*	2	5	7	12	128	173	215
Energy Storage	2	3	3	3	28	56	92
DG-Fossil	885	860	835	810	829	879	940
DG-Renewables	65	71	78	85	127	177	234
Smart Grid (CVR)	0	0	9	19	46	174	216
TOTAL	2,216	2,356	3,379	3,690	5,044	6,461	7,462
Total Annual Peak Load	25,519	25,929	26,525	27,077	28,674	30,379	32,312
% of Peak Load Supported by Demand-Side Resources	8.7%	9.1%	12.7%	13.6%	17.6%	21.3%	23.1%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-87. Projected Demand-Side Resource Peak Load Impact in Ohio through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

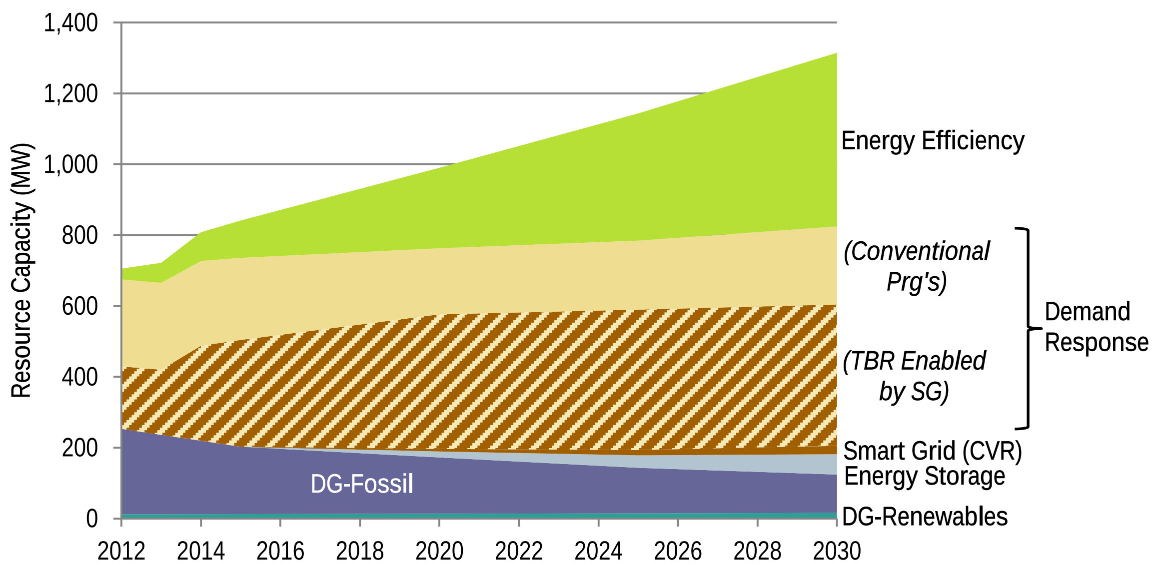
A.30 Oklahoma[94]

Table A-88. Projected Demand-Side Resource Capacity in Oklahoma through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	31	57	81	106	227	359	490
Demand Response (conventional)	245	245	239	232	186	195	220
Demand Response (smart grid-enabled)*	176	184	268	301	380	396	399
Energy Storage	0	0	0	0	17	35	57
DG-Fossil	241	224	207	190	159	128	108
DG-Renewables	12	12	12	13	14	15	16
Smart Grid (CVR)	0	0	0	0	7	15	23
TOTAL	705	722	808	841	990	1,143	1,315

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-88. Projected Demand-Side Resource Capacity in Oklahoma through 2030



[94] The forecast for Oklahoma assumes that the 2012 EE data available for Empire District Electric Company and Oklahoma Gas & Electric Company are cumulative. Navigant used 2011 EIA-861 data to estimate the incremental annual savings achieved in 2012. Furthermore, Navigant excluded approximately 1,700 MW of time-of-use rate program reported by Oklahoma Gas & Electric Company in FERC's DR survey, based on review of other available information. Also, note that Navigant scaled back Oklahoma's smart grid-enabled time-based rate programs in order to maintain consistency with Navigant's forecasts for conventional DR programs.

Table A-89. Projected Demand-Side Resource Annual Energy Impact in Oklahoma through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	152	281	405	525	1,131	1,787	2,439
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	485	445	405	365	297	230	184
DG-Renewables	31	31	32	32	33	36	38
Smart Grid [a c]	0	0	0	0	9	20	30
TOTAL	667	758	842	922	1,471	2,072	2,691
Total Annual Electricity Consumption (AEC) [d]	59,255	57,090	57,877	58,566	60,141	62,405	63,389
% of AEC Supported by Demand-Side Resources	1.1%	1.3%	1.5%	1.6%	2.4%	3.3%	4.2%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-89. Projected Demand-Side Resource Annual Energy Impact in Oklahoma through 2030

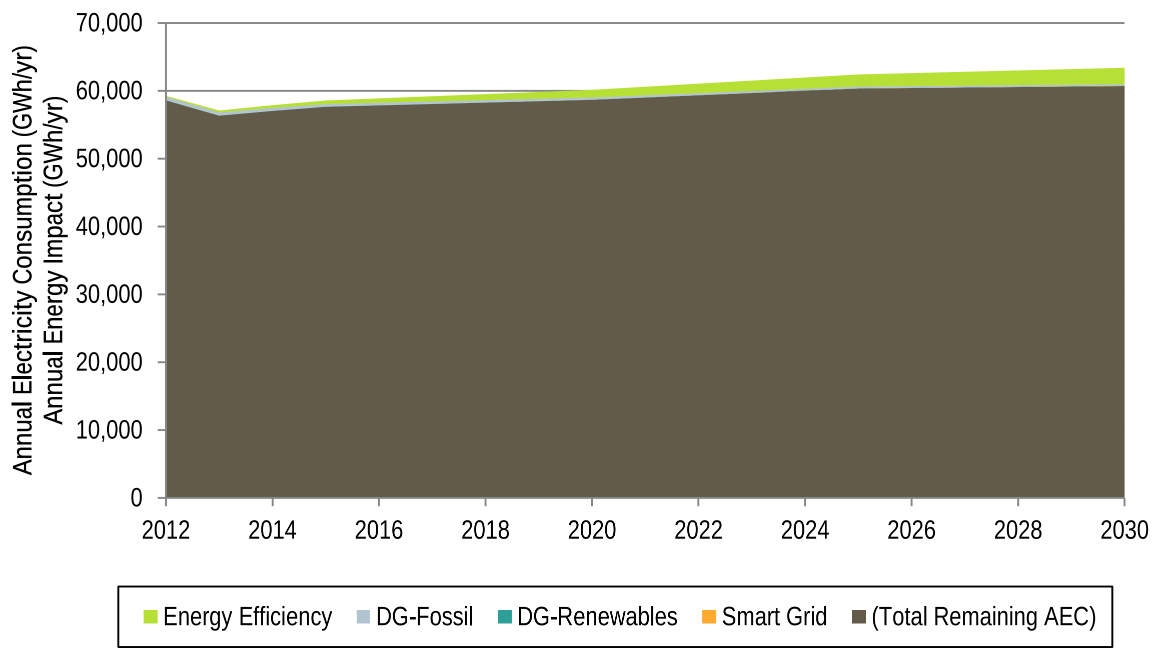
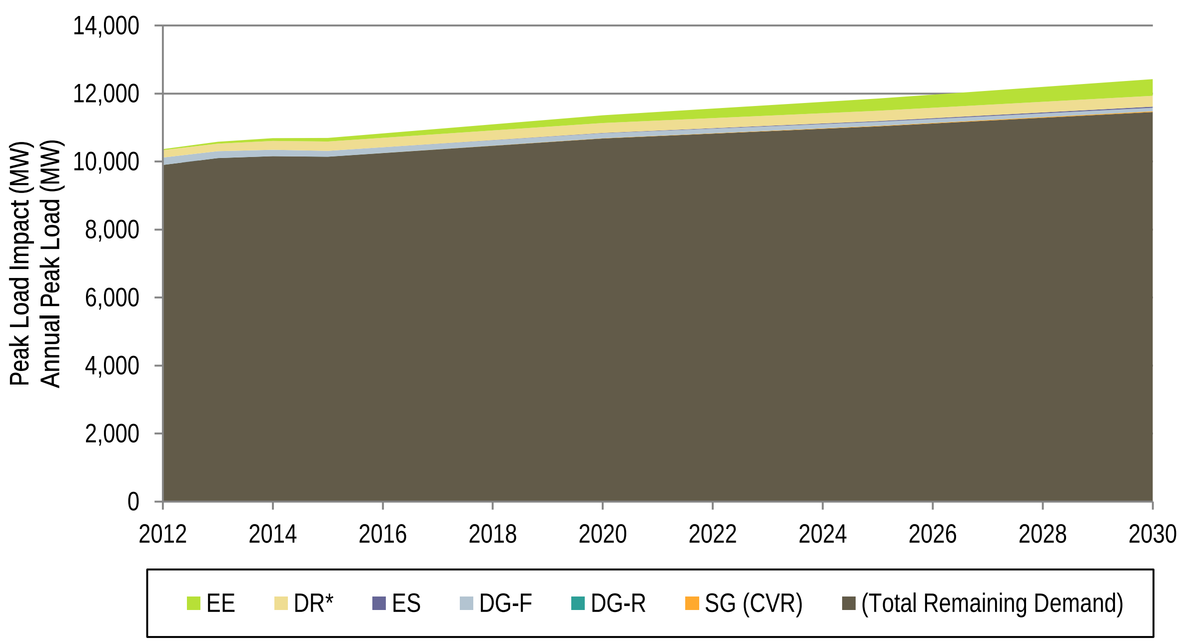


Table A-90. Projected Demand-Side Resource Peak Load Impact in Oklahoma through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	31	57	81	106	227	359	490
Demand Response (conventional)	137	138	140	138	120	126	139
Demand Response (smart grid-enabled)*	79	83	121	136	171	178	179
Energy Storage	0	0	0	0	10	21	34
DG-Fossil	217	202	186	171	143	116	97
DG-Renewables	1	1	2	2	3	3	4
Smart Grid (CVR)	0	0	0	0	7	15	23
TOTAL	466	480	530	552	681	818	968
Total Annual Peak Load	10,364	10,581	10,687	10,693	11,359	11,852	12,422
% of Peak Load Supported by Demand-Side Resources	4.5%	4.5%	5.0%	5.2%	6.0%	6.9%	7.8%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-90. Projected Demand-Side Resource Peak Load Impact in Oklahoma through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

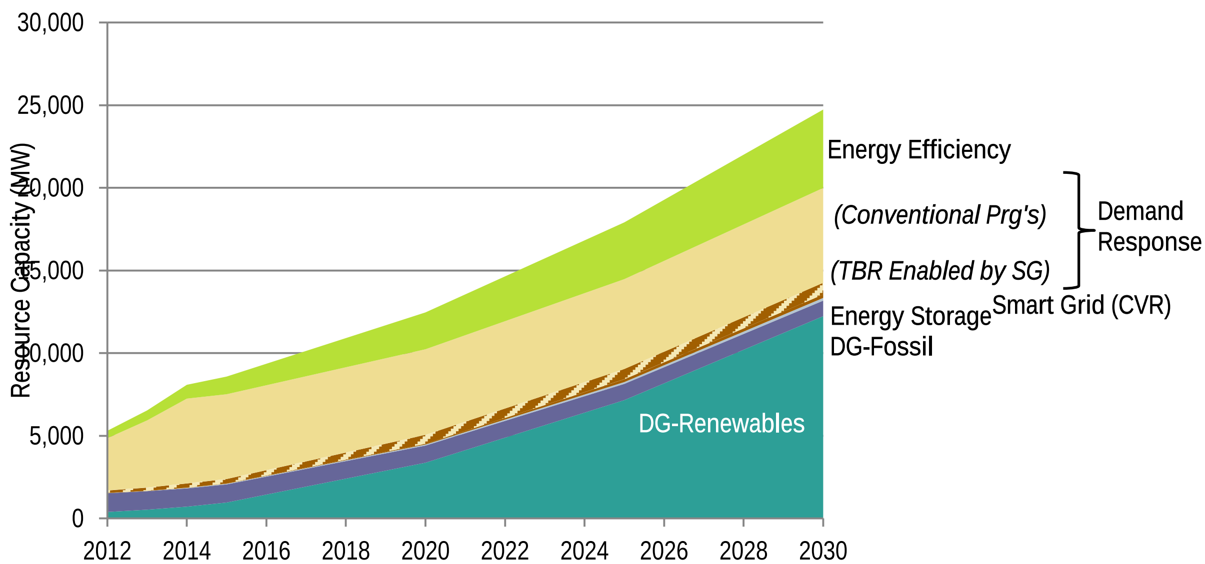
A.31 Pennsylvania[95]

Table A-91. Projected Demand-Side Resource Capacity in Pennsylvania through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	448	604	836	1,068	2,229	3,433	4,741
Demand Response (conventional)	3,156	4,058	5,127	5,124	5,177	5,433	5,741
Demand Response (smart grid-enabled)*	153	201	260	276	542	625	702
Energy Storage	7	8	28	36	63	109	165
DG-Fossil	1,135	1,120	1,105	1,097	1,036	984	940
DG-Renewables	394	533	716	966	3,374	7,159	12,235
Smart Grid (CVR)	11	11	13	16	44	166	206
TOTAL	5,304	6,535	8,086	8,583	12,464	17,910	24,732

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-91. Projected Demand-Side Resource Capacity in Pennsylvania through 2030



[95] EE savings for the Pennsylvania IOUs are based on the Act 129 targets.

Table A-92. Projected Demand-Side Resource Annual Energy Impact in Pennsylvania through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	2,131	2,870	3,975	5,081	10,598	16,327	22,543
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	1,596	1,591	1,587	1,589	1,496	1,409	1,327
DG-Renewables	1,188	1,377	1,612	1,929	4,856	9,445	15,604
Smart Grid [a c]	110	110	115	115	243	395	451
TOTAL	5,025	5,948	7,289	8,713	17,194	27,576	39,925
Total Annual Electricity Consumption (AEC) [d]	148,996	145,772	146,488	145,772	144,340	145,772	149,712
% of AEC Supported by Demand-Side Resources	3.4%	4.1%	5.0%	6.0%	11.9%	18.9%	26.7%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-92. Projected Demand-Side Resource Annual Energy Impact in Pennsylvania through 2030

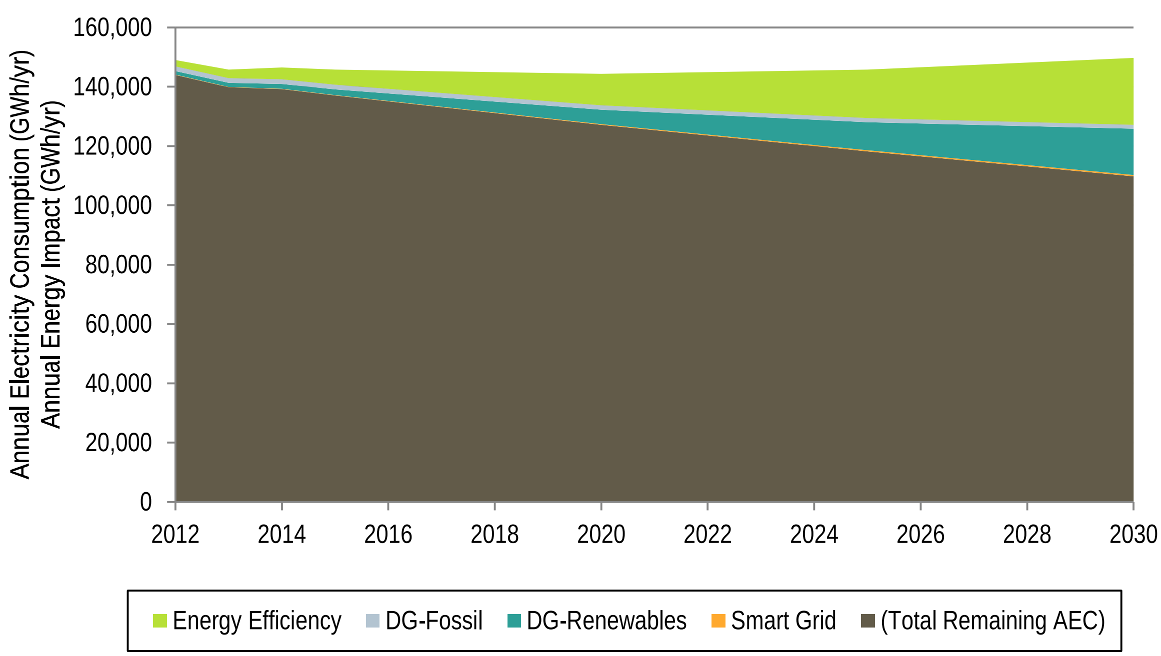
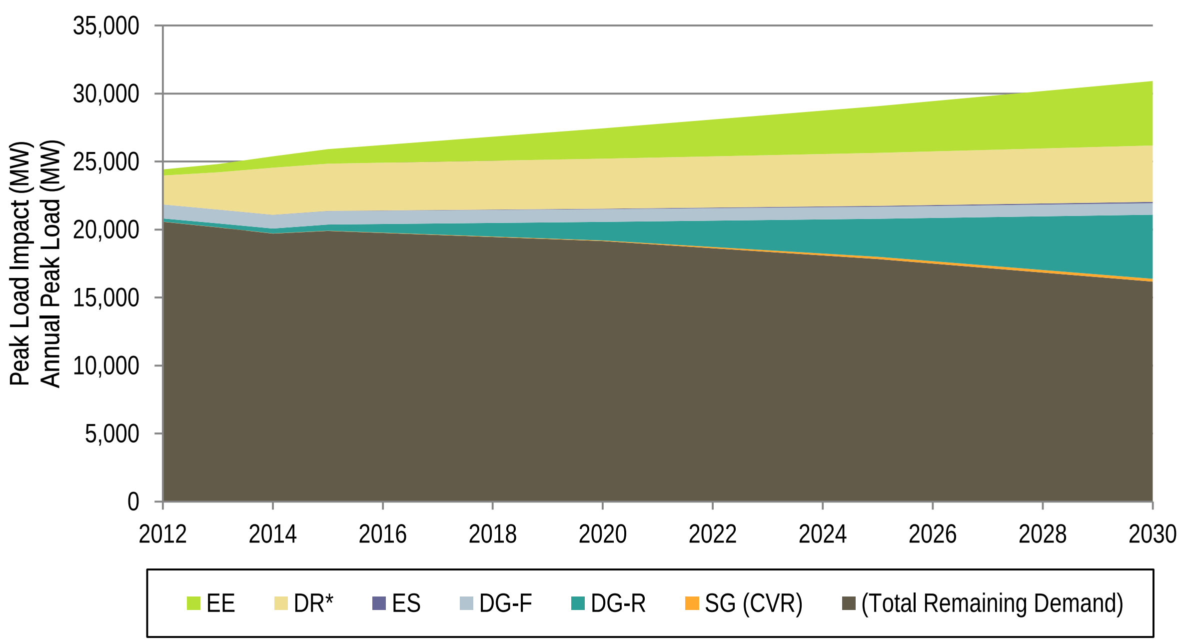


Table A-93. Projected Demand-Side Resource Peak Load Impact in Pennsylvania through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	448	604	836	1,068	2,229	3,433	4,741
Demand Response (conventional)	2,059	2,649	3,348	3,349	3,434	3,615	3,828
Demand Response (smart grid-enabled)*	69	91	117	124	244	281	316
Energy Storage	6	6	11	13	36	63	97
DG-Fossil	1,021	1,008	995	987	933	886	846
DG-Renewables	234	289	359	455	1,365	2,795	4,712
Smart Grid (CVR)	11	11	13	16	44	166	206
TOTAL	3,849	4,657	5,680	6,013	8,285	11,240	14,747
Total Annual Peak Load	24,418	24,810	25,380	25,908	27,436	29,068	30,917
% of Peak Load Supported by Demand-Side Resources	15.8%	18.8%	22.4%	23.2%	30.2%	38.7%	47.7%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-93. Projected Demand-Side Resource Peak Load Impact in Pennsylvania through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

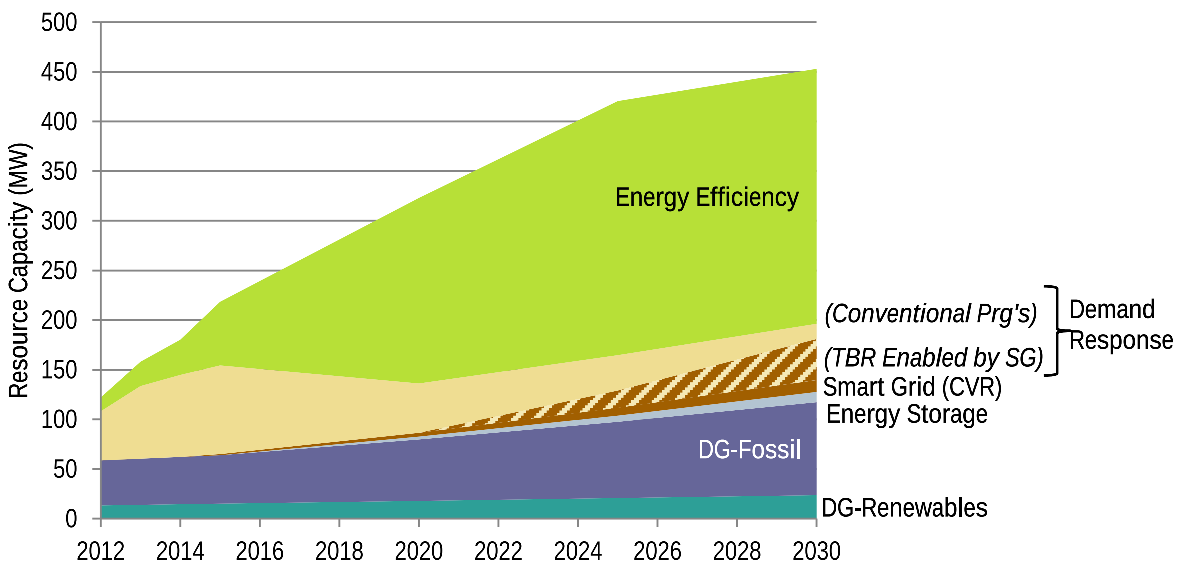
A.32 Rhode Island[96]

Table A-94. Projected Demand-Side Resource Capacity in Rhode Island through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	14	24	35	64	187	256	257
Demand Response (conventional)	49	73	83	89	50	36	15
Demand Response (smart grid-enabled)*	0	0	0	0	0	17	42
Energy Storage	0	0	0	0	3	6	10
DG-Fossil	45	46	48	49	62	77	94
DG-Renewables	13	14	15	15	18	21	24
Smart Grid (CVR)	0	0	0	1	4	8	12
TOTAL	122	158	180	218	323	421	453

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-94. Projected Demand-Side Resource Capacity in Rhode Island through 2030



[96] EE and DR forecasts are based on ISO-NE's 2012 Forecast Data File. The near-term Demand Response forecasts for New England states are based on the Real-Time Demand Response cleared in the primary Forward Capacity Auctions for ISO-NE, which show a significant decrease in committed DR capacity (approximately 1400 MW in 2015 to less than 900 MW in 2016). While this may be due to characteristics specific to New England's market, it is too soon to know whether increased availability of smart grid-enabled time-based rate programs in the area may influence the market trend. Navigant scaled back the forecast of Rhode Island's smart grid-enabled time-based rate programs in order to maintain consistency with the forecast for overall DR resource capacity. This assessment assumes that the overall DR capacity committed in 2016 grows gradually from 2016 through 2030.

Table A-95. Projected Demand-Side Resource Annual Energy Impact in Rhode Island through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	80	140	203	367	1,071	1,467	1,472
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	81	83	85	87	113	143	177
DG-Renewables	37	38	39	40	43	47	51
Smart Grid [a c]	0	0	0	0	2	6	12
TOTAL	199	261	327	494	1,230	1,663	1,712
Total Annual Electricity Consumption (AEC) [d]	7,800	7,867	7,934	7,867	8,069	8,270	8,203
% of AEC Supported by Demand-Side Resources	2.5%	3.3%	4.1%	6.3%	15.2%	20.1%	20.9%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-95. Projected Demand-Side Resource Annual Energy Impact in Rhode Island through 2030

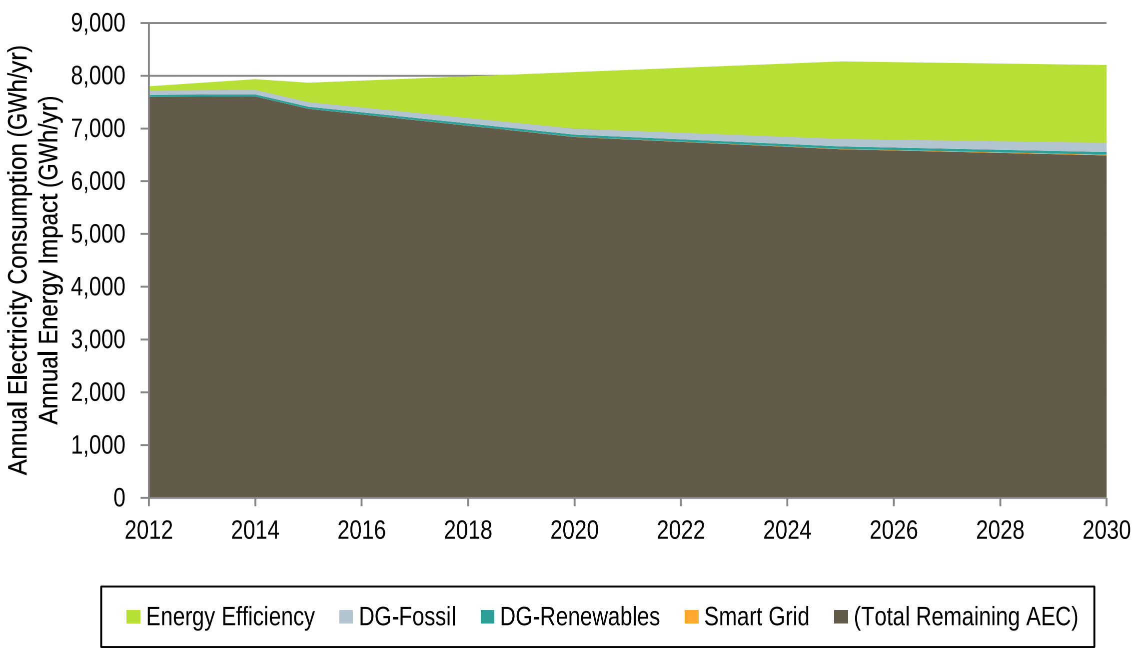
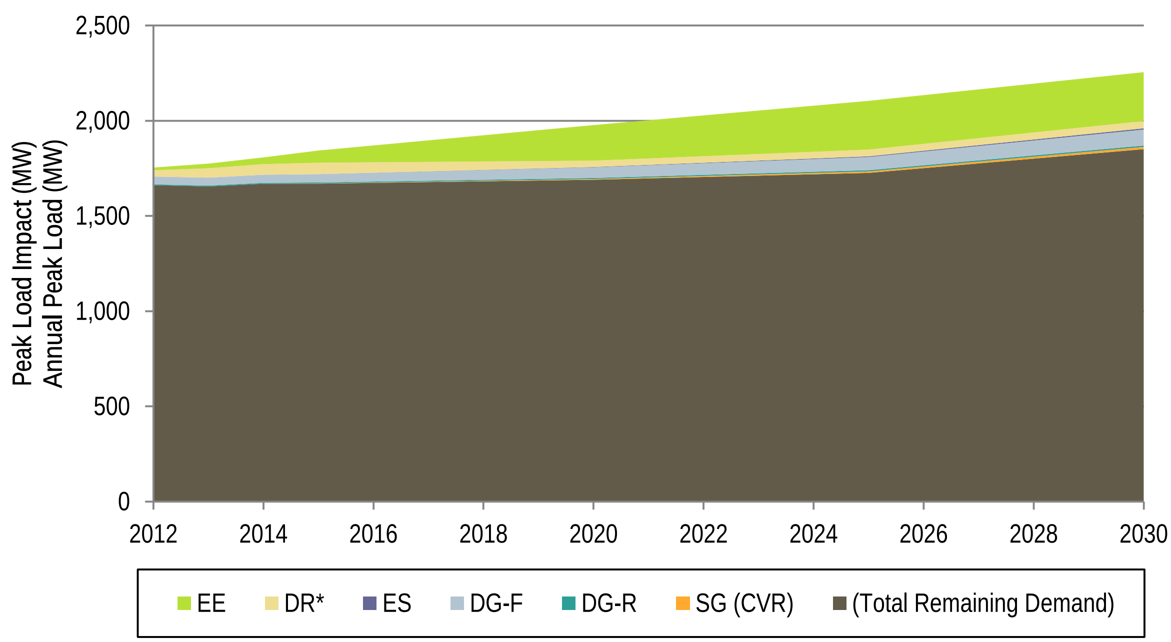


Table A-96. Projected Demand-Side Resource Peak Load Impact in Rhode Island through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	14	24	35	64	187	256	257
Demand Response (conventional)	33	49	55	60	33	28	19
Demand Response (smart grid-enabled)*	0	0	0	0	0	8	19
Energy Storage	0	0	0	0	2	4	6
DG-Fossil	41	42	43	44	56	69	84
DG-Renewables	5	5	5	5	6	6	7
Smart Grid (CVR)	0	0	0	1	4	8	12
TOTAL	92	120	138	174	287	378	404
Total Annual Peak Load	1,754	1,775	1,807	1,843	1,977	2,104	2,255
% of Peak Load Supported by Demand-Side Resources	5.3%	6.8%	7.7%	9.4%	14.5%	18.0%	17.9%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-96. Projected Demand-Side Resource Peak Load Impact in Rhode Island through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

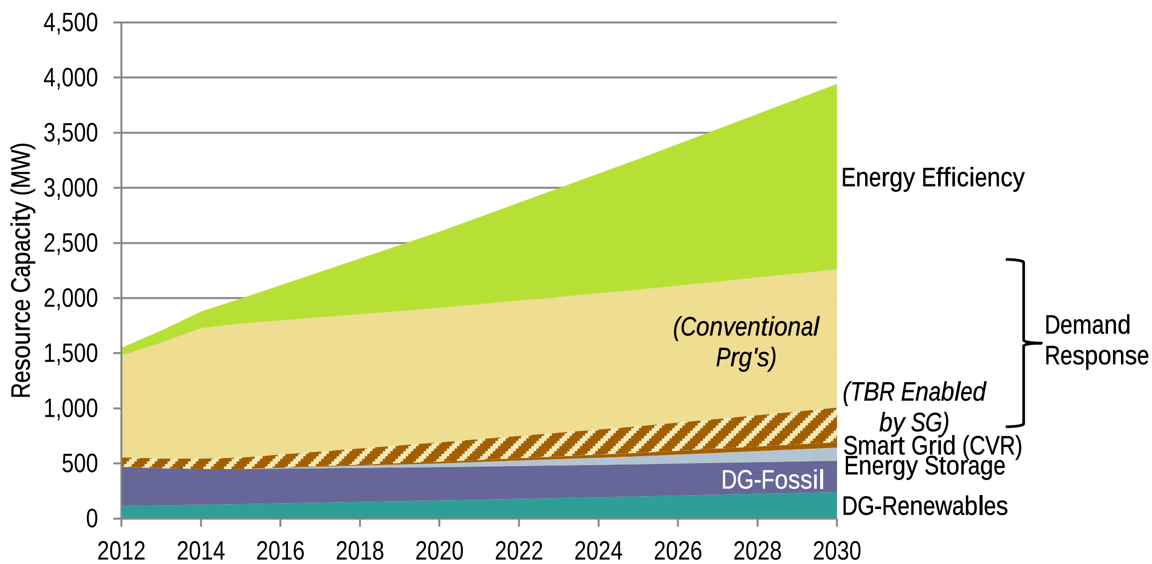
A.33 South Carolina[97]

Table A-97. Projected Demand-Side Resource Capacity in South Carolina through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	70	111	152	227	691	1,185	1,683
Demand Response (conventional)	925	1,049	1,182	1,214	1,220	1,238	1,254
Demand Response (smart grid-enabled)*	87	89	94	105	176	243	314
Energy Storage	0	0	0	0	34	73	119
DG-Fossil	354	337	325	317	303	292	284
DG-Renewables	114	120	125	131	164	200	241
Smart Grid (CVR)	0	0	0	0	14	31	49
TOTAL	1,549	1,705	1,878	1,995	2,602	3,261	3,943

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-97. Projected Demand-Side Resource Capacity in South Carolina through 2030



[97] The forecast for South Carolina assumes that the 2012 EE data available for Progress Energy Carolinas and Virginia Electric and Power Company are cumulative. Navigant used 2011 EIA-861 data to estimate the incremental annual savings achieved in 2012.

Table A-98. Projected Demand-Side Resource Annual Energy Impact in South Carolina through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	530	847	1,155	1,727	5,266	9,025	12,819
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	418	392	379	373	367	365	368
DG-Renewables	558	573	587	601	668	748	844
Smart Grid [a c]	0	0	0	0	14	29	44
TOTAL	1,507	1,812	2,121	2,702	6,315	10,168	14,075
Total Annual Electricity Consumption (AEC) [d]	80,600	79,600	80,600	78,601	87,483	91,701	93,811
% of AEC Supported by Demand-Side Resources	1.9%	2.3%	2.6%	3.4%	7.2%	11.1%	15.0%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-98. Projected Demand-Side Resource Annual Energy Impact in South Carolina through 2030

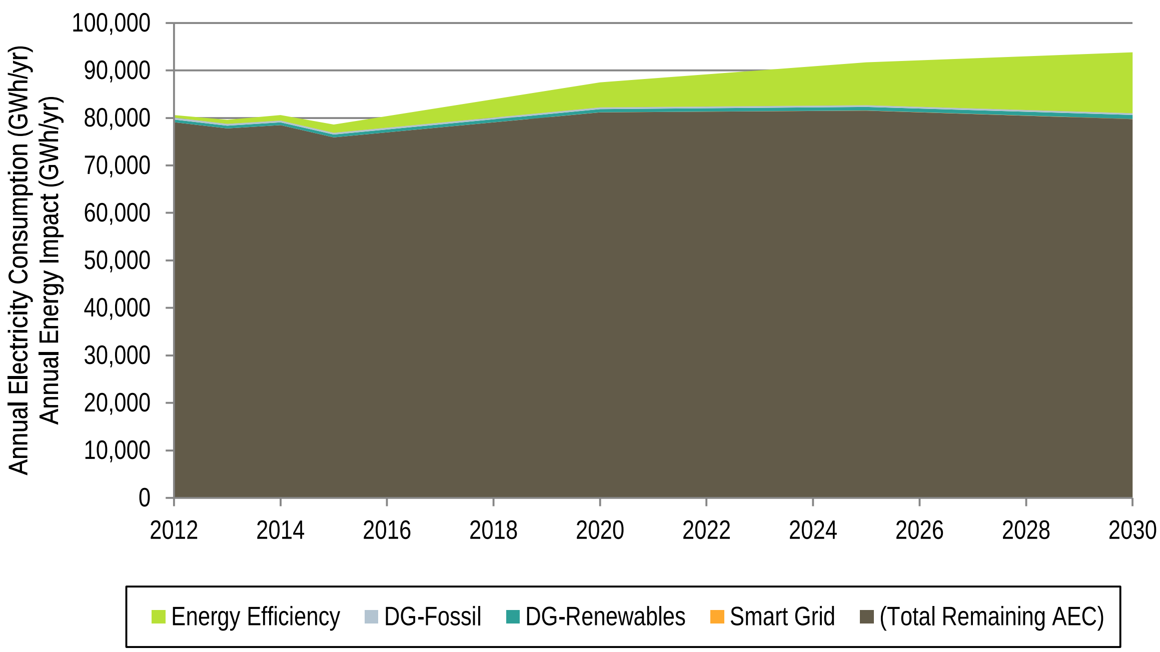
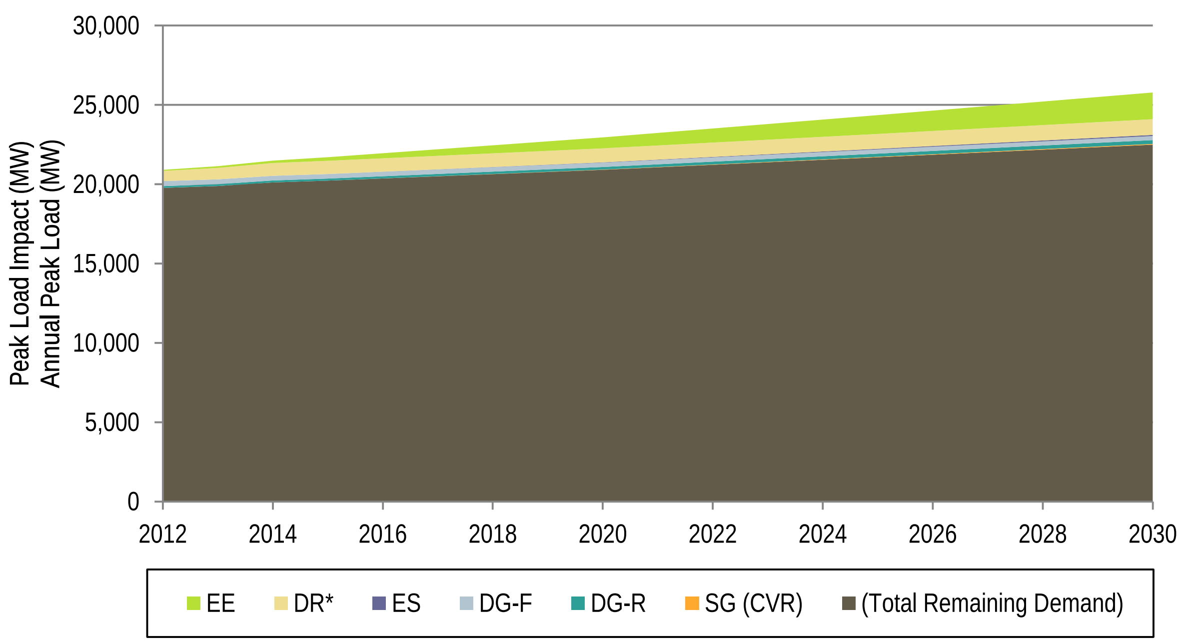


Table A-99. Projected Demand-Side Resource Peak Load Impact in South Carolina through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	70	111	152	227	691	1,185	1,683
Demand Response (conventional)	600	679	763	786	802	826	849
Demand Response (smart grid-enabled)*	39	40	42	47	79	109	141
Energy Storage	0	0	0	0	20	43	71
DG-Fossil	319	303	293	286	272	262	255
DG-Renewables	114	120	125	131	164	200	241
Smart Grid (CVR)	0	0	0	0	14	31	49
TOTAL	1,141	1,252	1,375	1,477	2,043	2,656	3,288
Total Annual Peak Load	20,903	21,134	21,484	21,700	22,948	24,351	25,778
% of Peak Load Supported by Demand-Side Resources	5.5%	5.9%	6.4%	6.8%	8.9%	10.9%	12.8%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-99. Projected Demand-Side Resource Peak Load Impact in South Carolina through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

A.34 South Dakota

Table A-100. Projected Demand-Side Resource Capacity in South Dakota through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	1	2	3	4	10	16	22
Demand Response (conventional)	460	494	568	610	652	693	737
Demand Response (smart grid-enabled)*	15	15	17	17	19	20	25
Energy Storage	0	0	0	0	25	53	87
DG-Fossil	63	63	62	62	64	67	69
DG-Renewables	9	9	9	9	9	10	10
Smart Grid (CVR)	0	0	2	2	2	76	101
TOTAL	548	583	661	703	780	934	1,051

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-100. Projected Demand-Side Resource Capacity in South Dakota through 2030

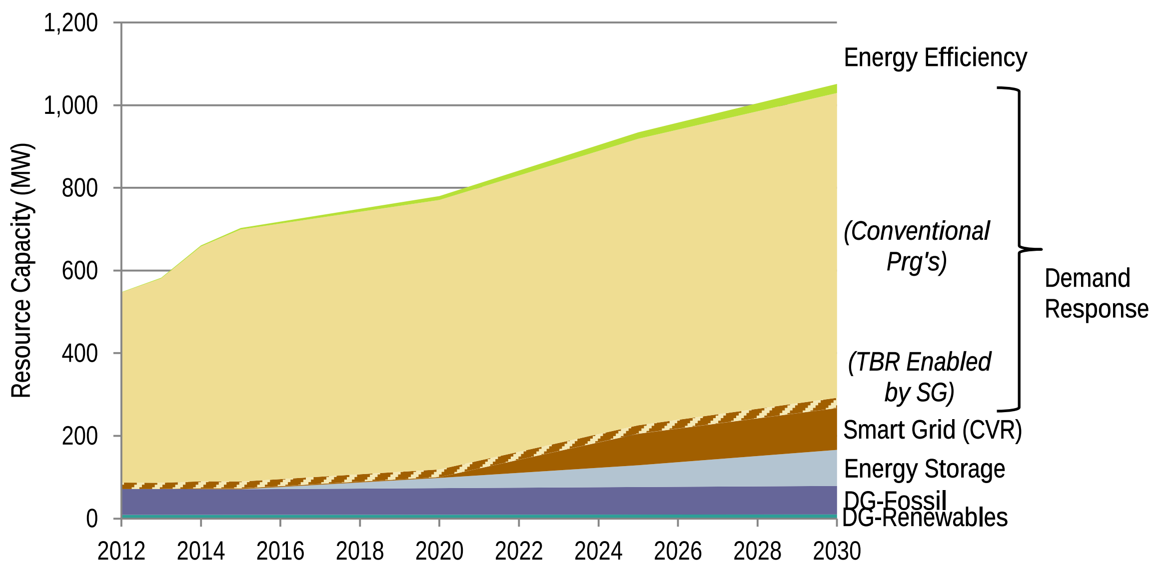


Table A-101. Projected Demand-Side Resource Annual Energy Impact in South Dakota through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	6	11	16	23	59	98	137
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	77	77	76	76	78	81	83
DG-Renewables	30	30	30	30	31	32	32
Smart Grid [a c]	0	0	5	5	5	13	16
TOTAL	113	117	128	134	174	223	269
Total Annual Electricity Consumption (AEC) [d]	7,661	7,595	7,879	7,486	7,661	7,813	7,966
% of AEC Supported by Demand-Side Resources	1.5%	1.5%	1.6%	1.8%	2.3%	2.9%	3.4%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-101. Projected Demand-Side Resource Annual Energy Impact in South Dakota through 2030

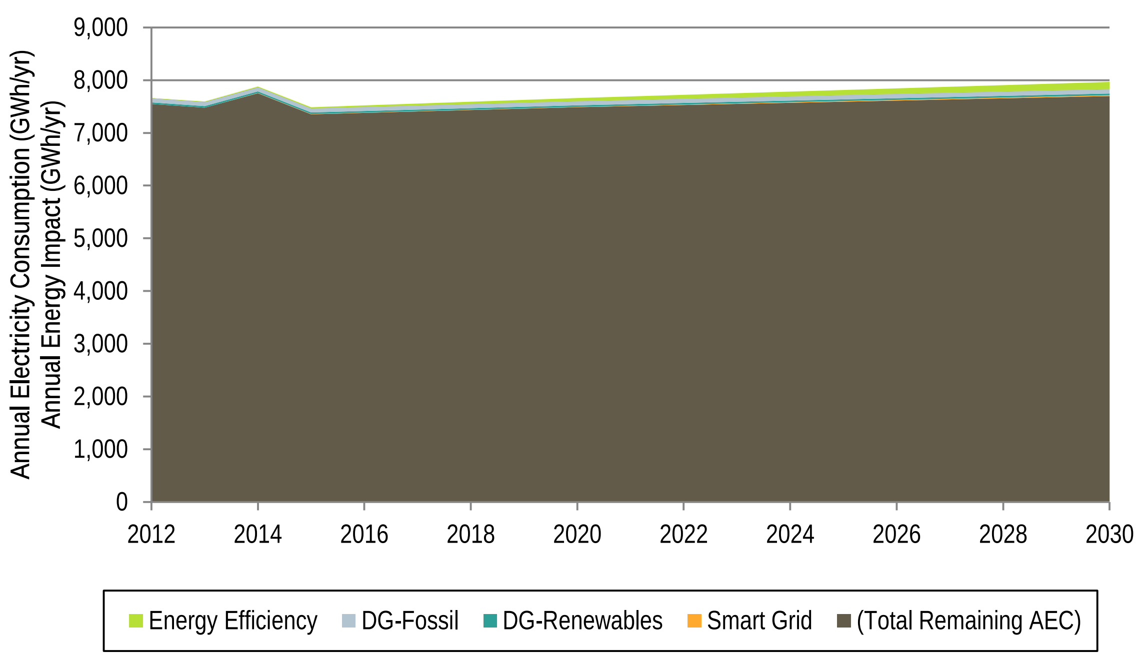
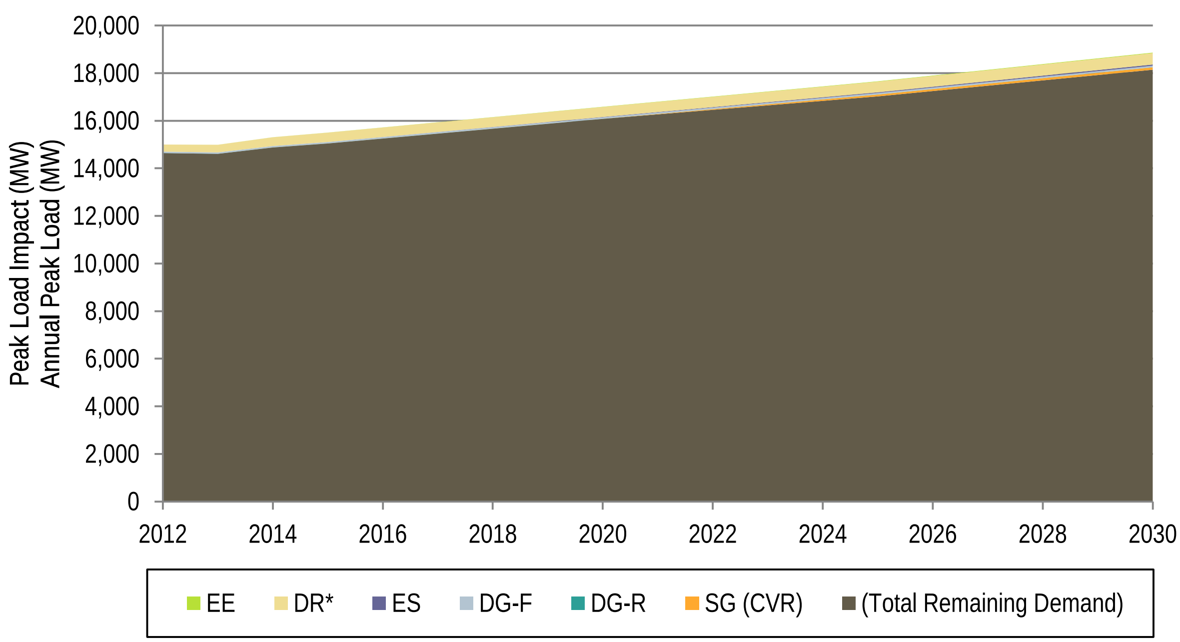


Table A-102. Projected Demand-Side Resource Peak Load Impact in South Dakota through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	1	2	3	4	10	16	22
Demand Response (conventional)	290	312	358	384	411	437	465
Demand Response (smart grid-enabled)*	7	7	8	8	8	9	11
Energy Storage	0	0	0	0	15	31	52
DG-Fossil	57	56	56	56	58	60	62
DG-Renewables	4	4	4	4	4	5	5
Smart Grid (CVR)	0	0	2	2	2	76	101
TOTAL	359	381	431	457	508	634	718
Total Annual Peak Load	14,999	14,989	15,306	15,501	16,586	17,656	18,860
% of Peak Load Supported by Demand-Side Resources	2.4%	2.5%	2.8%	3.0%	3.1%	3.6%	3.8%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-102. Projected Demand-Side Resource Peak Load Impact in South Dakota through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

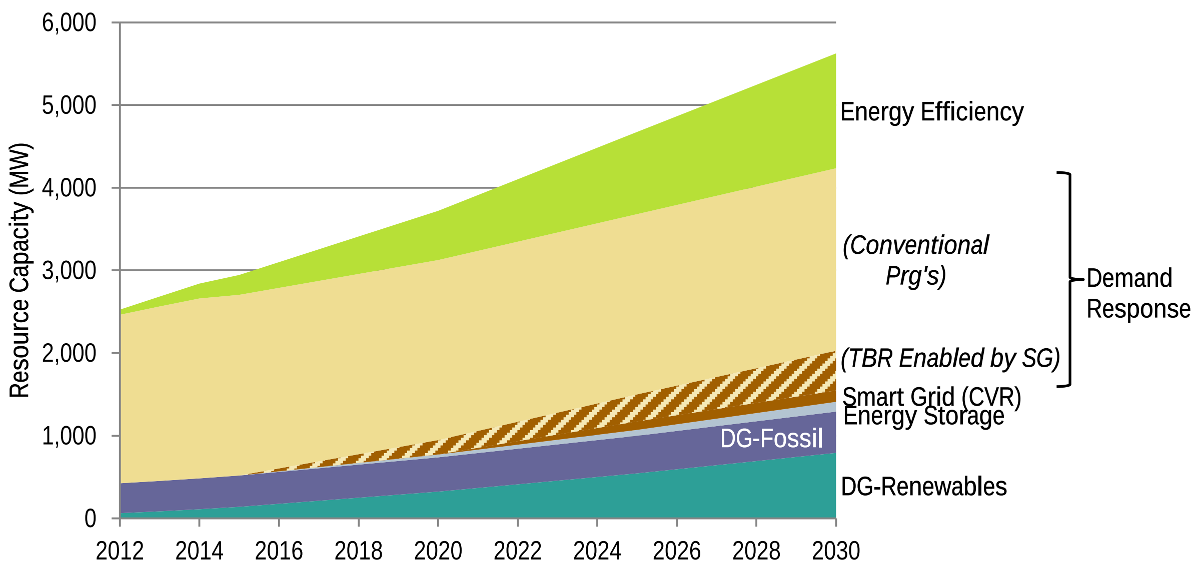
A.35 Tennessee[98]

Table A-103. Projected Demand-Side Resource Capacity in Tennessee through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	62	120	180	240	595	994	1,389
Demand Response (conventional)	2,038	2,111	2,176	2,185	2,178	2,180	2,208
Demand Response (smart grid-enabled)*	0	0	0	0	172	326	480
Energy Storage	0	0	0	0	33	71	118
DG-Fossil	362	368	373	379	415	455	499
DG-Renewables	63	86	111	140	324	545	793
Smart Grid (CVR)	0	0	0	1	3	103	137
TOTAL	2,526	2,684	2,841	2,945	3,720	4,675	5,625

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-103. Projected Demand-Side Resource Capacity in Tennessee through 2030



[98] Navigant based the EE and DR forecasts for Tennessee on 2011 IRP and time-of-use programs reported in FERC's DR survey, and verified the results with Tennessee Valley Authority.

Table A-104. Projected Demand-Side Resource Annual Energy Impact in Tennessee through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	260	503	756	1,010	2,500	4,177	5,837
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	1,314	1,318	1,323	1,327	1,405	1,492	1,591
DG-Renewables	187	220	255	295	539	833	1,167
Smart Grid [a c]	0	0	1	1	4	116	157
TOTAL	1,761	2,041	2,334	2,632	4,447	6,618	8,753
Total Annual Electricity Consumption (AEC) [d]	98,709	93,393	95,671	94,153	100,733	107,314	110,098
% of AEC Supported by Demand-Side Resources	1.8%	2.2%	2.4%	2.8%	4.4%	6.2%	7.9%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-104. Projected Demand-Side Resource Annual Energy Impact in Tennessee through 2030

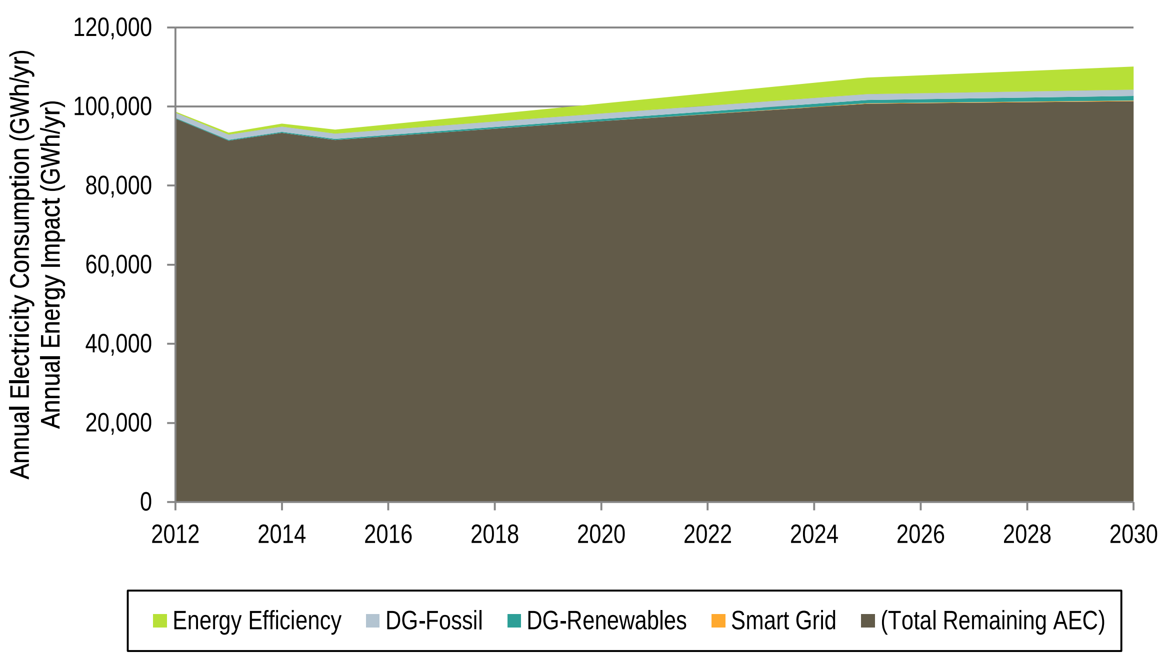
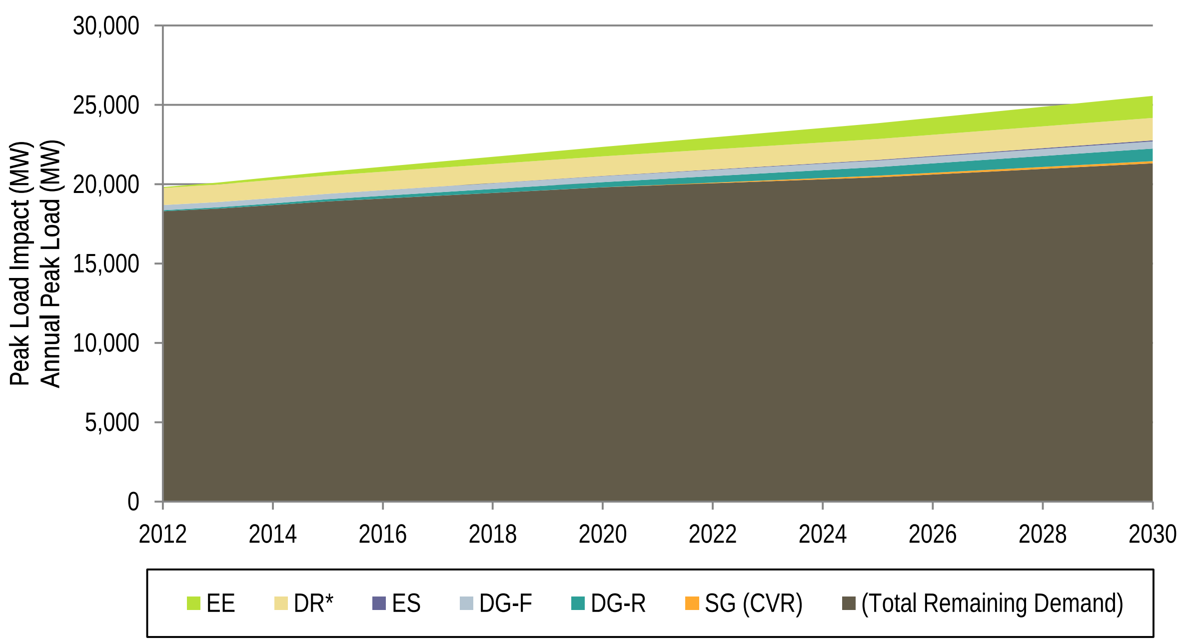


Table A-105. Projected Demand-Side Resource Peak Load Impact in Tennessee through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	62	120	180	240	595	994	1,389
Demand Response (conventional)	1,071	1,109	1,143	1,148	1,157	1,170	1,196
Demand Response (smart grid-enabled)*	0	0	0	0	77	147	216
Energy Storage	0	0	0	0	20	42	70
DG-Fossil	326	331	336	341	373	409	449
DG-Renewables	62	85	110	139	323	544	791
Smart Grid (CVR)	0	0	0	1	3	103	137
TOTAL	1,521	1,644	1,769	1,869	2,549	3,409	4,250
Total Annual Peak Load	19,817	20,101	20,449	20,784	22,350	23,841	25,564
% of Peak Load Supported by Demand-Side Resources	7.7%	8.2%	8.7%	9.0%	11.4%	14.3%	16.6%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-105. Projected Demand-Side Resource Peak Load Impact in Tennessee through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

A.36 Texas[99]

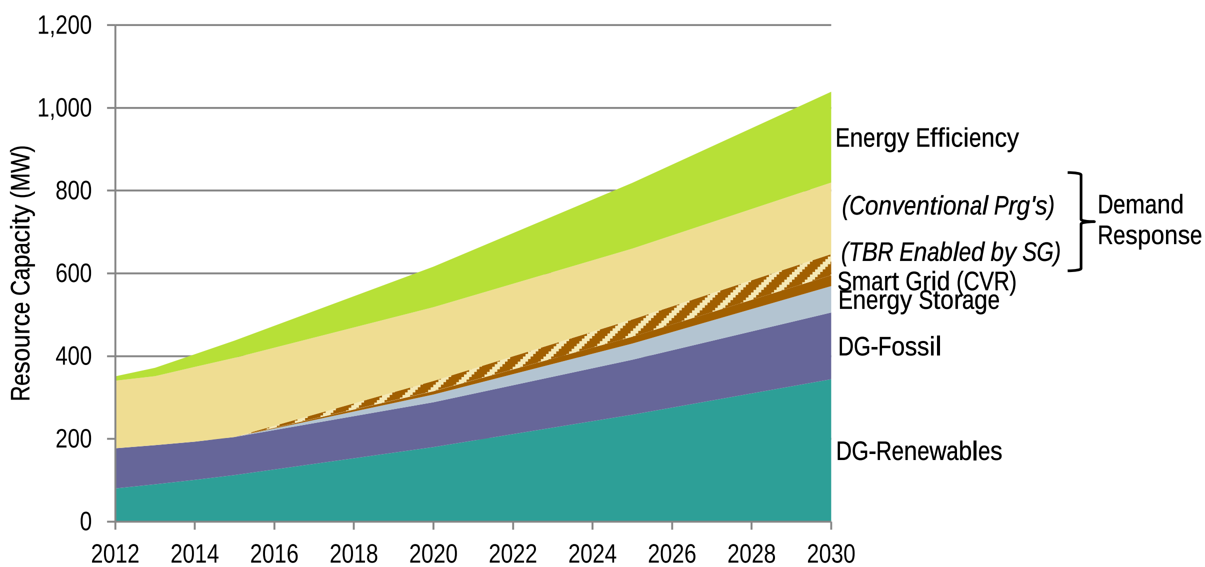
Note that the data in this section covers only the parts of Texas that are served by utilities within the Eastern Interconnection.

Table A-106. Projected Demand-Side Resource Capacity in Texas through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	11	20	31	42	98	159	220
Demand Response (conventional)	163	167	181	191	179	171	173
Demand Response (smart grid-enabled)*	0	0	0	0	25	42	51
Energy Storage	0	0	0	0	19	39	64
DG-Fossil	97	95	92	92	108	133	161
DG-Renewables	80	90	101	113	180	258	344
Smart Grid (CVR)	0	0	0	0	8	17	26
TOTAL	351	372	405	438	616	819	1,039

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-106. Projected Demand-Side Resource Capacity in Texas through 2030



[99] The forecast for Texas assumes that the 2012 EE data available for Southwestern Public Service Company is cumulative. Navigant used 2011 EIA-861 data to estimate the incremental annual savings achieved in 2012.

Table A-107. Projected Demand-Side Resource Annual Energy Impact in Texas through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	60	114	172	234	550	893	1,234
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	312	313	313	316	380	465	565
DG-Renewables	271	289	306	326	429	552	691
Smart Grid [a c]	0	0	0	0	11	23	36
TOTAL	642	715	791	876	1,370	1,934	2,525
Total Annual Electricity Consumption (AEC) [d]	70,489	67,913	68,850	69,669	71,543	74,236	75,407
% of AEC Supported by Demand-Side Resources	0.9%	1.1%	1.1%	1.3%	1.9%	2.6%	3.3%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-107. Projected Demand-Side Resource Annual Energy Impact in Texas through 2030

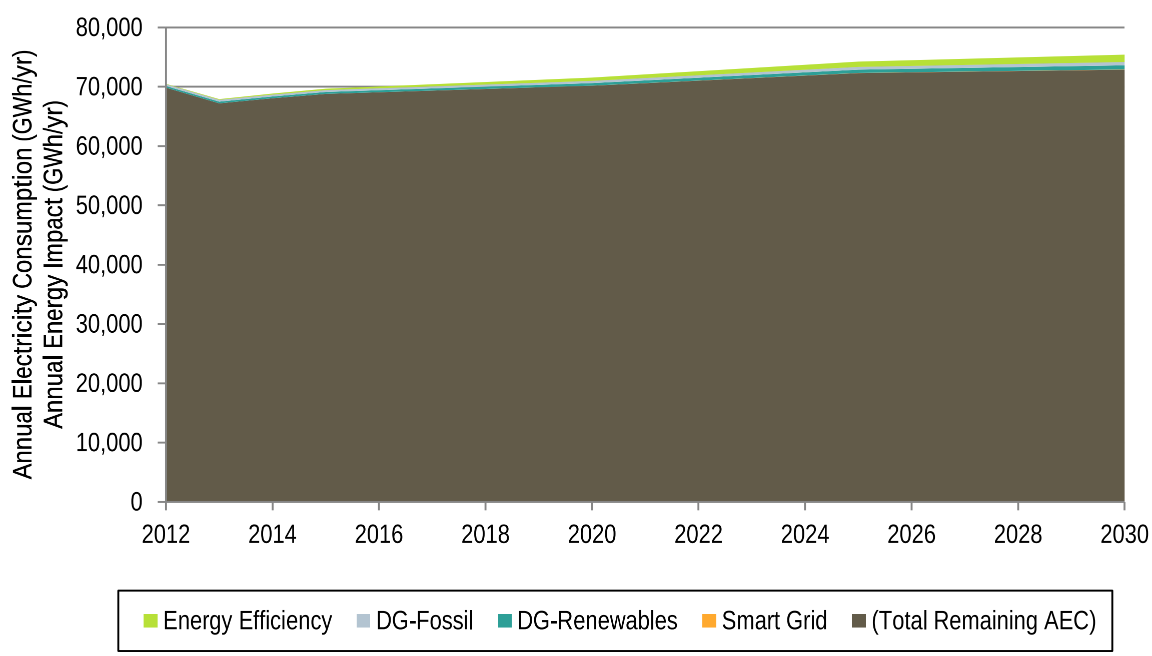
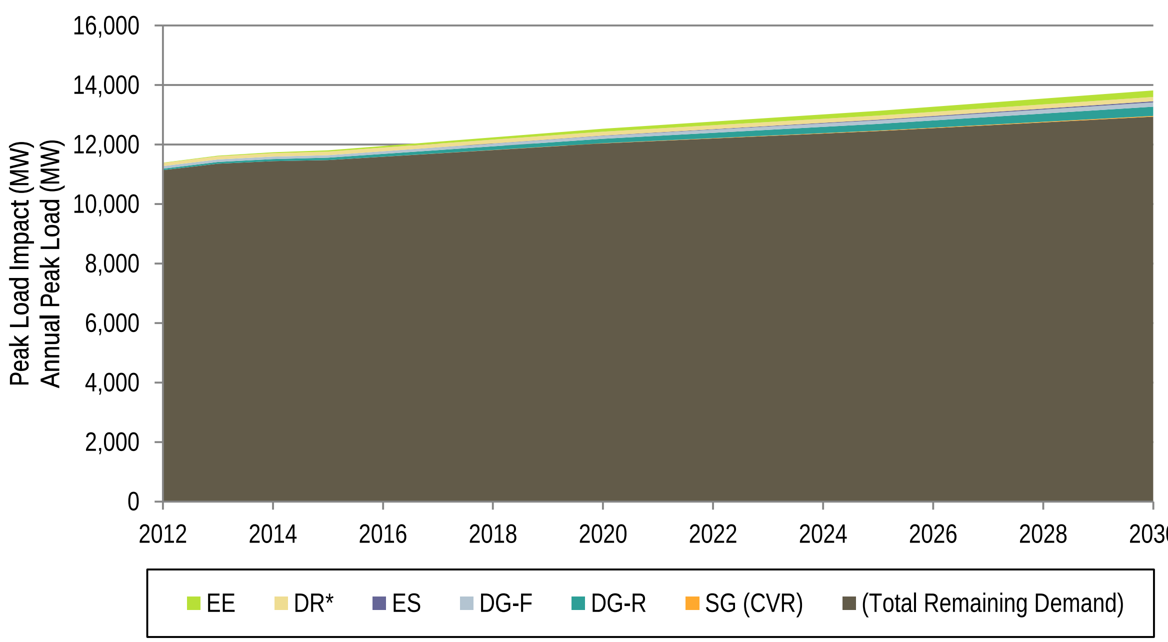


Table A-108. Projected Demand-Side Resource Peak Load Impact in Texas through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	11	20	31	42	98	159	220
Demand Response (conventional)	105	107	116	123	119	118	121
Demand Response (smart grid-enabled)*	0	0	0	0	11	19	23
Energy Storage	0	0	0	0	11	23	38
DG-Fossil	87	85	83	83	98	120	145
DG-Renewables	49	59	69	81	148	225	310
Smart Grid (CVR)	0	0	0	0	8	17	26
TOTAL	252	271	299	328	493	680	882
Total Annual Peak Load	11,389	11,625	11,740	11,804	12,530	13,131	13,817
% of Peak Load Supported by Demand-Side Resources	2.2%	2.3%	2.5%	2.8%	3.9%	5.2%	6.4%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-108. Projected Demand-Side Resource Peak Load Impact in Texas through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

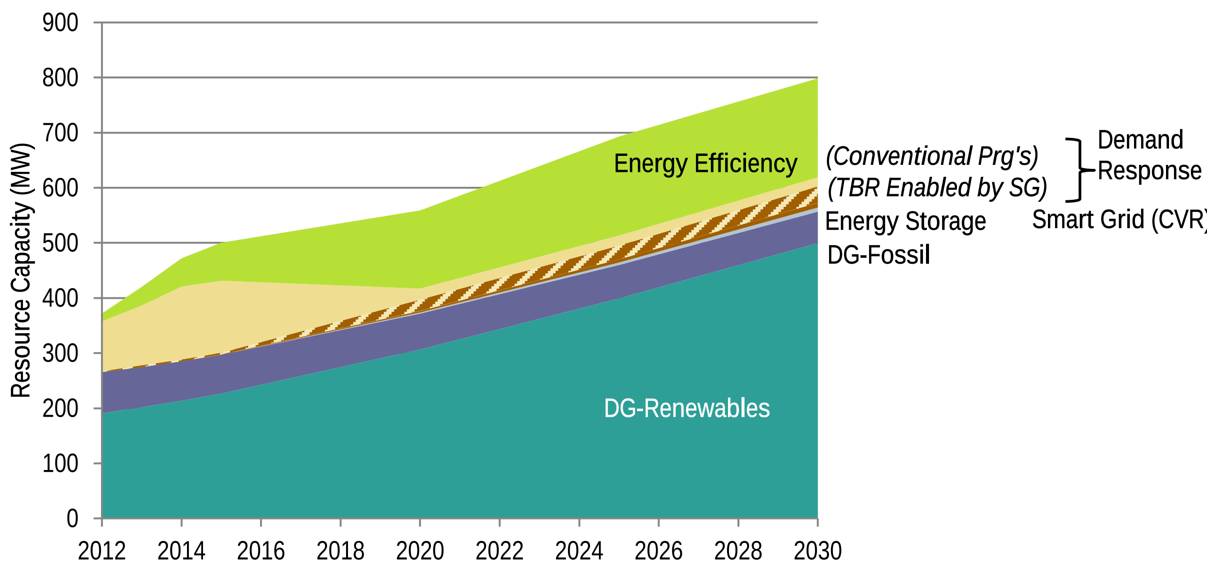
A.37 Vermont[100]

Table A-109. Projected Demand-Side Resource Capacity in Vermont through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	15	34	51	69	142	180	180
Demand Response (conventional)	90	109	132	131	20	18	17
Demand Response (smart grid-enabled)*	2	3	3	3	21	25	30
Energy Storage	0	0	0	0	2	4	7
DG-Fossil	75	73	72	70	65	61	57
DG-Renewables	191	202	214	227	307	399	500
Smart Grid (CVR)	0	0	0	1	3	6	8
TOTAL	372	420	472	500	559	693	799

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-109. Projected Demand-Side Resource Capacity in Vermont through 2030



[100] EE and DR forecasts are based on ISO-NE's 2012 Forecast Data File. The near-term Demand Response forecasts for New England states are based on the Real-Time Demand Response cleared in the primary Forward Capacity Auctions for ISO-NE, which show a significant decrease in committed DR capacity (approximately 1400 MW in 2015 to less than 900 MW in 2016). While this may be due to characteristics specific to New England's market, it is too soon to know whether increased availability of smart grid-enabled time-based rate programs in the area may influence the market trend. Navigant scaled back the forecast of Vermont's smart grid-enabled time-based rate programs in order to maintain consistency with the forecast for overall DR resource capacity. This assessment assumes that the overall DR capacity committed in 2016 grows gradually from 2016 through 2030.

Table A-110. Projected Demand-Side Resource Annual Energy Impact in Vermont through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	91	211	321	431	886	1,122	1,122
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	85	84	84	83	82	83	85
DG-Renewables	781	796	812	828	933	1,058	1,192
Smart Grid [a c]	0	0	0	0	2	4	8
TOTAL	957	1,091	1,216	1,343	1,904	2,267	2,407
Total Annual Electricity Consumption (AEC) [d]	5,598	5,647	5,695	5,647	5,791	5,936	5,888
% of AEC Supported by Demand-Side Resources	17.1%	19.3%	21.4%	23.8%	32.9%	38.2%	40.9%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-110. Projected Demand-Side Resource Annual Energy Impact in Vermont through 2030

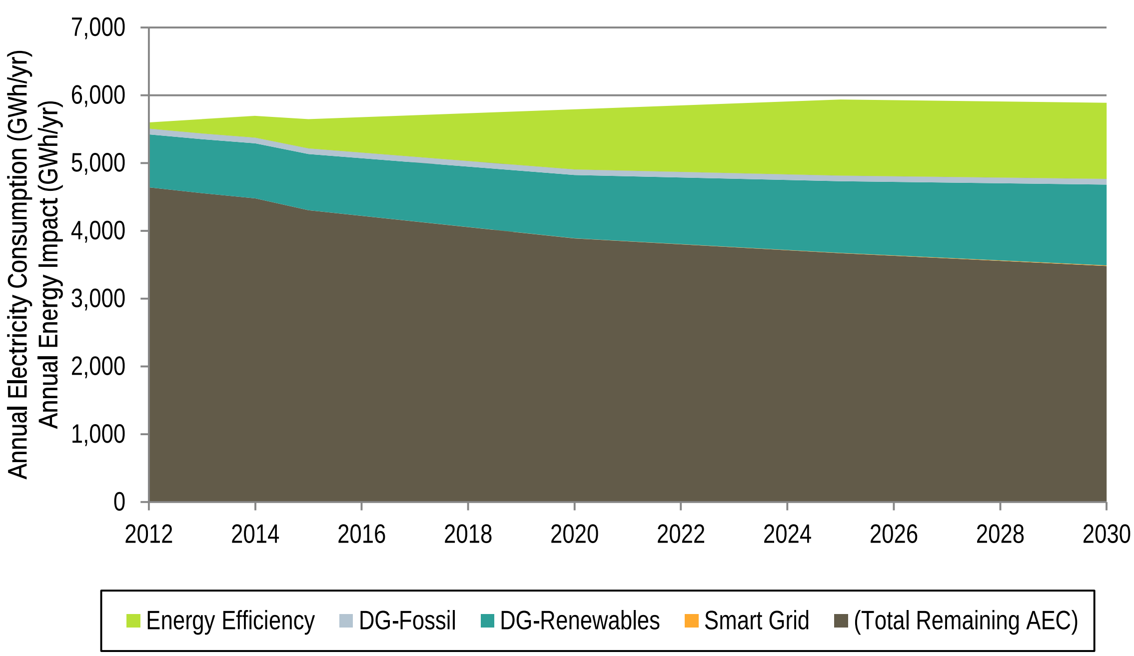
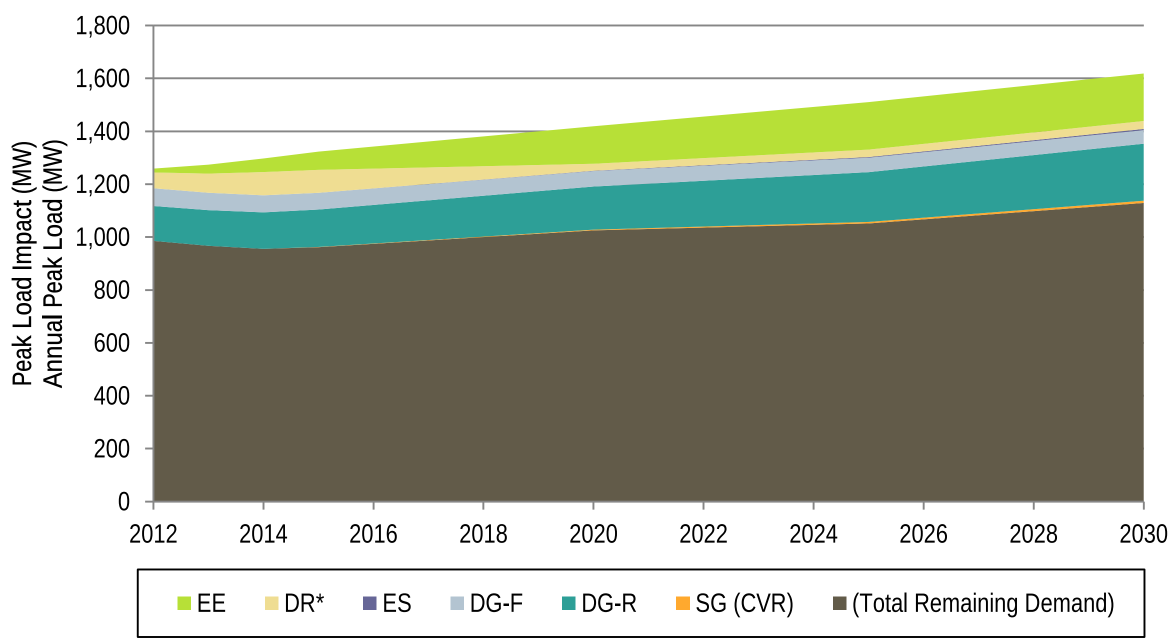


Table A-111. Projected Demand-Side Resource Peak Load Impact in Vermont through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	15	34	51	69	142	180	180
Demand Response (conventional)	59	71	87	85	17	17	17
Demand Response (smart grid-enabled)*	1	1	1	1	9	11	13
Energy Storage	0	0	0	0	1	3	4
DG-Fossil	67	66	65	63	58	55	51
DG-Renewables	132	135	138	141	163	188	216
Smart Grid (CVR)	0	0	0	1	3	6	8
TOTAL	273	307	342	361	394	459	490
Total Annual Peak Load	1,259	1,274	1,297	1,323	1,419	1,510	1,618
% of Peak Load Supported by Demand-Side Resources	21.7%	24.1%	26.3%	27.3%	27.7%	30.4%	30.2%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-111. Projected Demand-Side Resource Peak Load Impact in Vermont through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

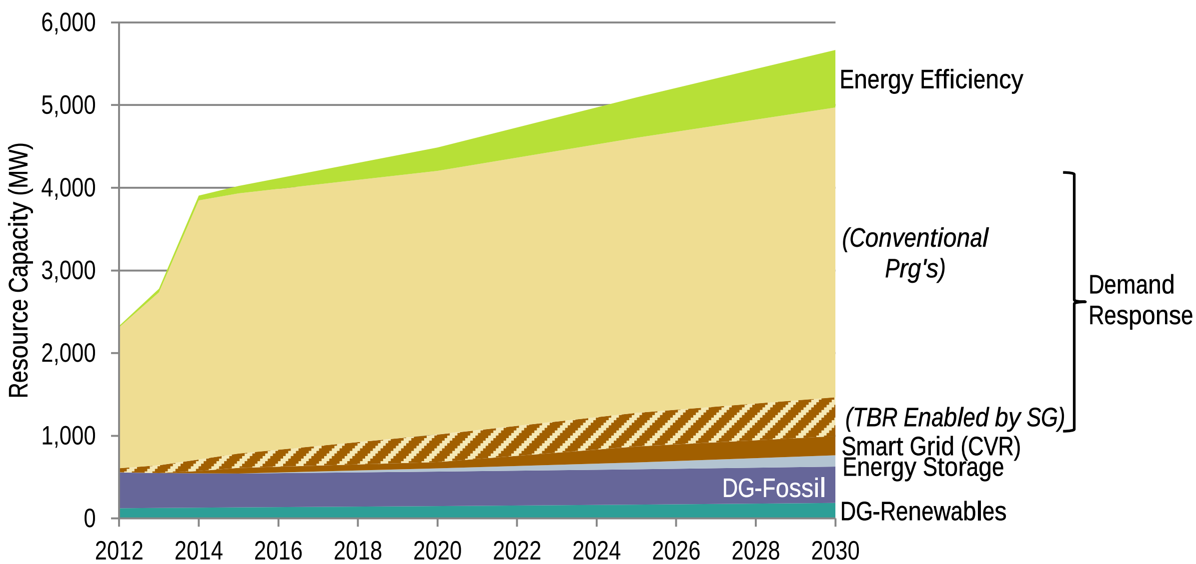
A.38 Virginia[101]

Table A-112. Projected Demand-Side Resource Capacity in Virginia through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	17	44	58	90	283	488	696
Demand Response (conventional)	1,706	2,092	3,133	3,148	3,188	3,328	3,506
Demand Response (smart grid-enabled)*	50	95	140	173	334	406	469
Energy Storage	0	0	0	0	39	83	137
DG-Fossil	432	421	415	409	417	427	439
DG-Renewables	124	128	131	134	150	167	188
Smart Grid (CVR)	0	0	28	68	76	193	232
TOTAL	2,330	2,779	3,905	4,022	4,487	5,093	5,667

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-112. Projected Demand-Side Resource Capacity in Virginia through 2030



[101] The forecast for Virginia assumes that the 2012 EE data available for Virginia Electric and Power Company is cumulative. Navigant used 2011 EIA-861 data to estimate the incremental annual savings achieved in 2012. Furthermore, the forecast assumes that the majority of the EE and DR reported for WV and VA by Appalachian Power occurs in WV.

Table A-113. Projected Demand-Side Resource Annual Energy Impact in Virginia through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	82	207	276	425	1,342	2,317	3,302
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	611	585	580	575	605	641	683
DG-Renewables	641	657	669	683	734	800	886
Smart Grid [a c]	0	0	135	280	320	451	498
TOTAL	1,333	1,449	1,659	1,963	3,000	4,208	5,369
Total Annual Electricity Consumption (AEC) [d]	110,380	109,012	110,380	107,644	119,807	125,584	128,473
% of AEC Supported by Demand-Side Resources	1.2%	1.3%	1.5%	1.8%	2.5%	3.4%	4.2%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-113. Projected Demand-Side Resource Annual Energy Impact in Virginia through 2030

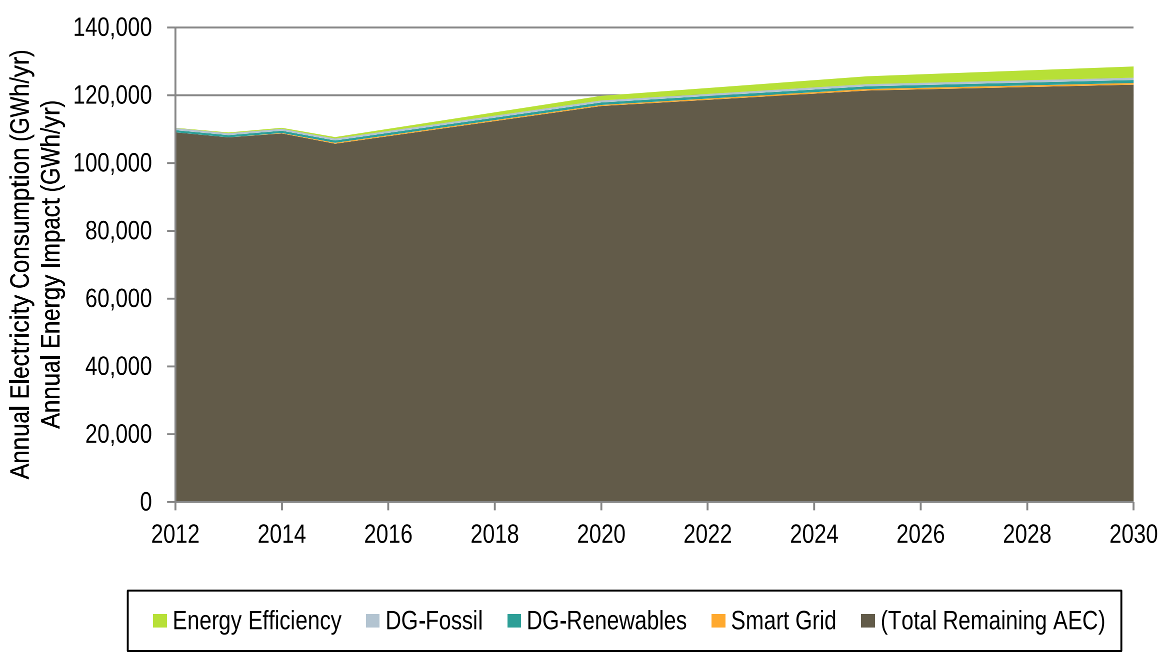
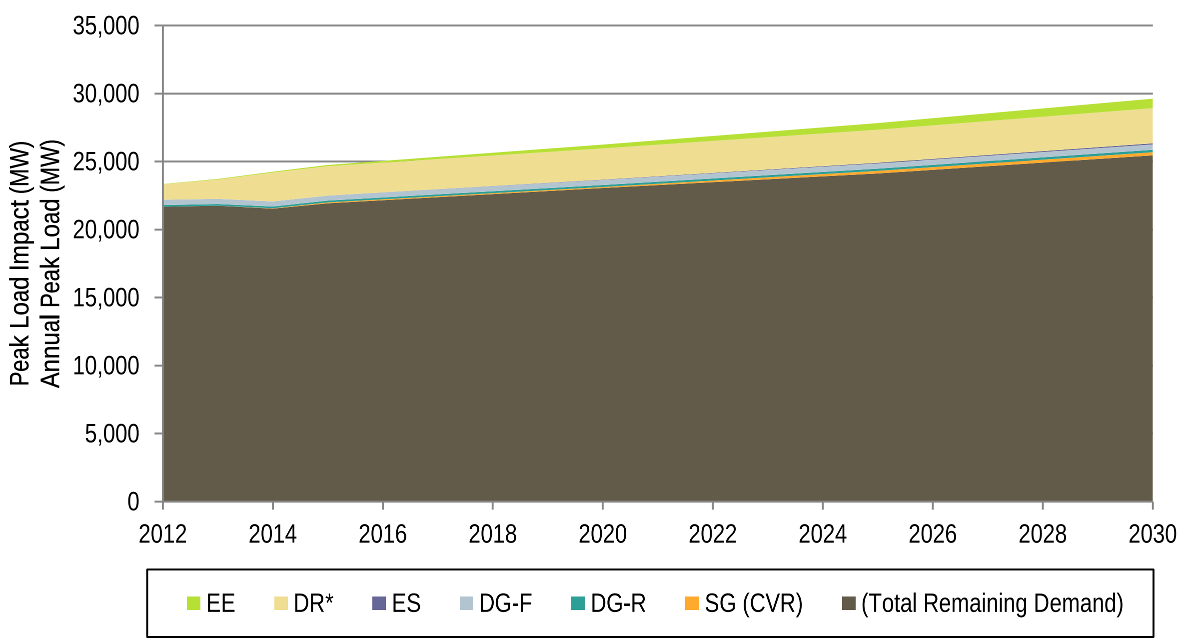


Table A-114. Projected Demand-Side Resource Peak Load Impact in Virginia through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	17	44	58	90	283	488	696
Demand Response (conventional)	1,120	1,380	2,066	2,082	2,141	2,246	2,375
Demand Response (smart grid-enabled)*	23	43	63	78	150	183	211
Energy Storage	0	0	0	0	23	49	81
DG-Fossil	389	379	374	368	376	385	395
DG-Renewables	122	126	128	131	144	160	178
Smart Grid (CVR)	0	0	28	68	76	193	232
TOTAL	1,671	1,971	2,717	2,817	3,193	3,704	4,168
Total Annual Peak Load	23,349	23,720	24,251	24,745	26,245	27,825	29,619
% of Peak Load Supported by Demand-Side Resources	7.2%	8.3%	11.2%	11.4%	12.2%	13.3%	14.1%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-114. Projected Demand-Side Resource Peak Load Impact in Virginia through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

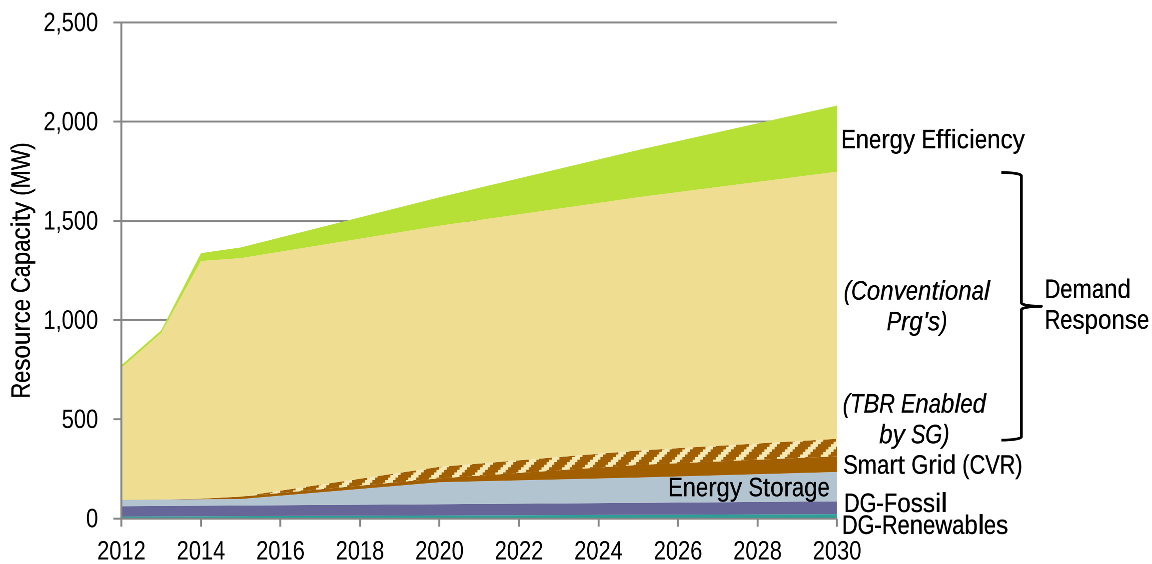
A.39 West Virginia[102]

Table A-115. Projected Demand-Side Resource Capacity in West Virginia through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	13	13	40	54	143	238	333
Demand Response (conventional)	666	839	1,198	1,202	1,215	1,276	1,347
Demand Response (smart grid-enabled)*	0	0	0	0	58	72	88
Energy Storage	32	33	33	33	111	128	148
DG-Fossil	52	52	53	53	57	60	65
DG-Renewables	10	11	12	12	15	19	22
Smart Grid (CVR)	0	0	3	12	20	64	79
TOTAL	773	949	1,337	1,366	1,619	1,857	2,081

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-115. Projected Demand-Side Resource Capacity in West Virginia through 2030



[102] The forecast assumes that the majority of the EE and DR reported for WV and VA by Appalachian Power occurs in WV.

Table A-116. Projected Demand-Side Resource Annual Energy Impact in West Virginia through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	101	104	305	413	1,103	1,831	2,563
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	138	139	141	143	155	167	182
DG-Renewables	48	50	51	52	58	65	72
Smart Grid [a c]	0	0	32	56	92	130	143
TOTAL	287	293	530	665	1,408	2,193	2,960
Total Annual Electricity Consumption (AEC) [d]	31,282	30,894	31,282	30,506	33,953	35,591	36,409
% of AEC Supported by Demand-Side Resources	0.9%	0.9%	1.7%	2.2%	4.1%	6.2%	8.1%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-116. Projected Demand-Side Resource Annual Energy Impact in West Virginia through 2030

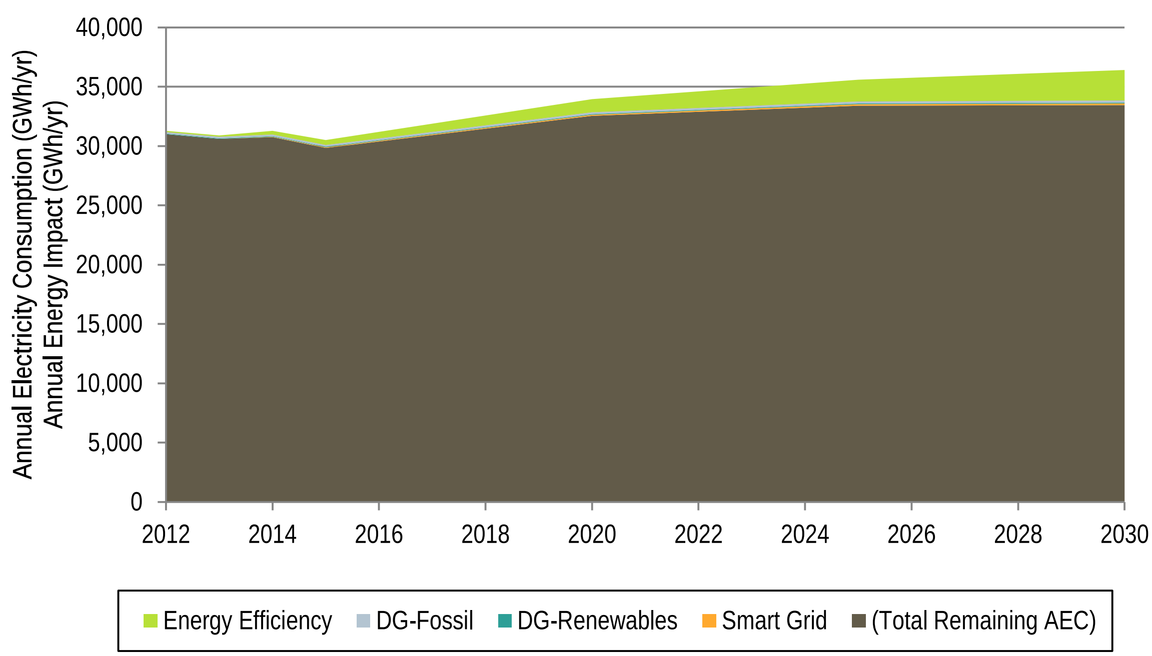
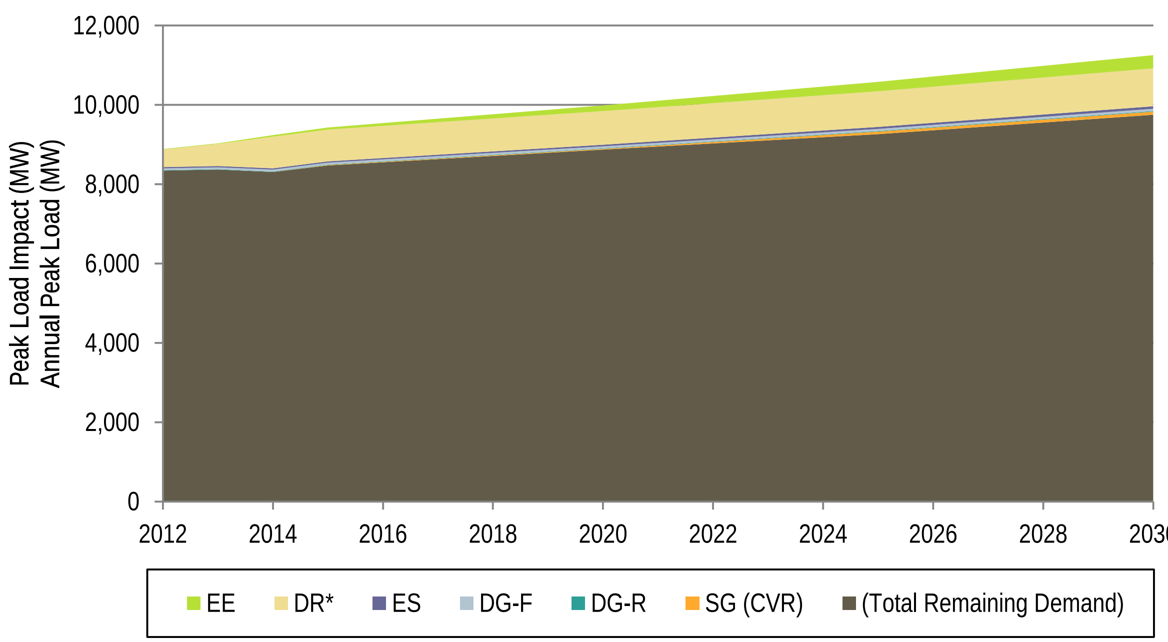


Table A-117. Projected Demand-Side Resource Peak Load Impact in West Virginia through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	13	13	40	54	143	238	333
Demand Response (conventional)	443	559	797	800	821	865	915
Demand Response (smart grid-enabled)*	0	0	0	0	26	33	40
Energy Storage	32	33	33	33	41	51	63
DG-Fossil	47	47	48	48	51	54	58
DG-Renewables	10	10	10	10	12	13	15
Smart Grid (CVR)	0	0	3	12	20	64	79
TOTAL	545	662	930	957	1,114	1,318	1,503
Total Annual Peak Load	8,887	9,030	9,237	9,429	9,985	10,579	11,252
% of Peak Load Supported by Demand-Side Resources	6.1%	7.3%	10.1%	10.2%	11.2%	12.5%	13.4%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-117. Projected Demand-Side Resource Peak Load Impact in West Virginia through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

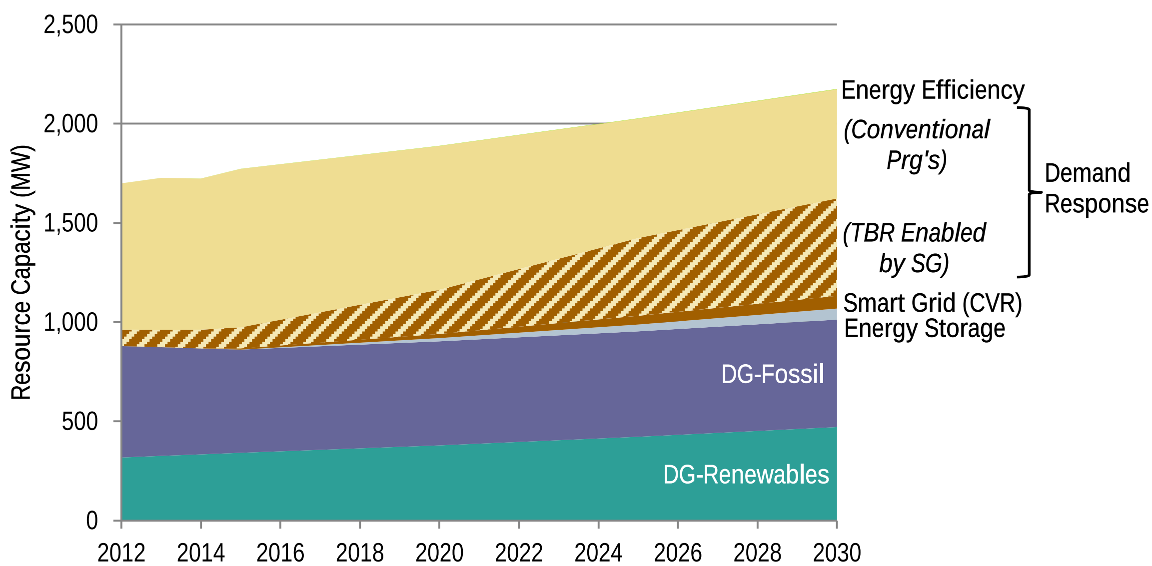
A.40 Wisconsin[103]

Table A-11818. Projected Demand-Side Resource Capacity in Wisconsin through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	0	0	1	1	1	2	2
Demand Response (conventional)	737	765	761	799	724	601	550
Demand Response (smart grid-enabled)*	83	88	95	105	223	392	491
Energy Storage	0	0	0	0	16	34	56
DG-Fossil	562	548	534	520	524	531	541
DG-Renewables	317	326	333	341	379	422	471
Smart Grid (CVR)	0	0	0	7	21	44	64
TOTAL	1,699	1,727	1,724	1,773	1,889	2,027	2,175

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-118. Projected Demand-Side Resource Capacity in Wisconsin through 2030



[103] EE and DR forecasts for are based on the WI Strategic Energy Analysis report.

Table A-119. Projected Demand-Side Resource Annual Energy Impact in Wisconsin through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Annual Energy Impact (GWh/yr)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	729	1,462	2,200	2,940	5,396	7,529	8,639
Demand Response [a b]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Energy Storage [a]	N/A	N/A	N/A	N/A	N/A	N/A	N/A
DG-Fossil	1,570	1,523	1,476	1,429	1,409	1,395	1,389
DG-Renewables	1,519	1,550	1,575	1,602	1,709	1,847	2,020
Smart Grid [a c]	0	0	0	4	19	45	93
TOTAL	3,818	4,535	5,250	5,975	8,532	10,815	12,141
Total Annual Electricity Consumption (AEC) [d]	59,974	61,642	56,440	60,072	59,778	64,195	66,452
% of AEC Supported by Demand-Side Resources	6.4%	7.4%	9.3%	9.9%	14.3%	16.8%	18.3%

a. *Energy impact from demand response programs, distributed energy storage systems, and time-based rate programs are expected to be negligible.*
b. *Includes conventional DR programs and Smart Grid-enabled time-based rate programs.*
c. *Conservation voltage reduction programs only.*
d. *Based on 2011 electricity sales based on EIA-861 data, and annual growth rate of electricity consumption for each Census Division based on 2012 EIA Annual Energy Outlook.*

Figure A-119. Projected Demand-Side Resource Annual Energy Impact in Wisconsin through 2030

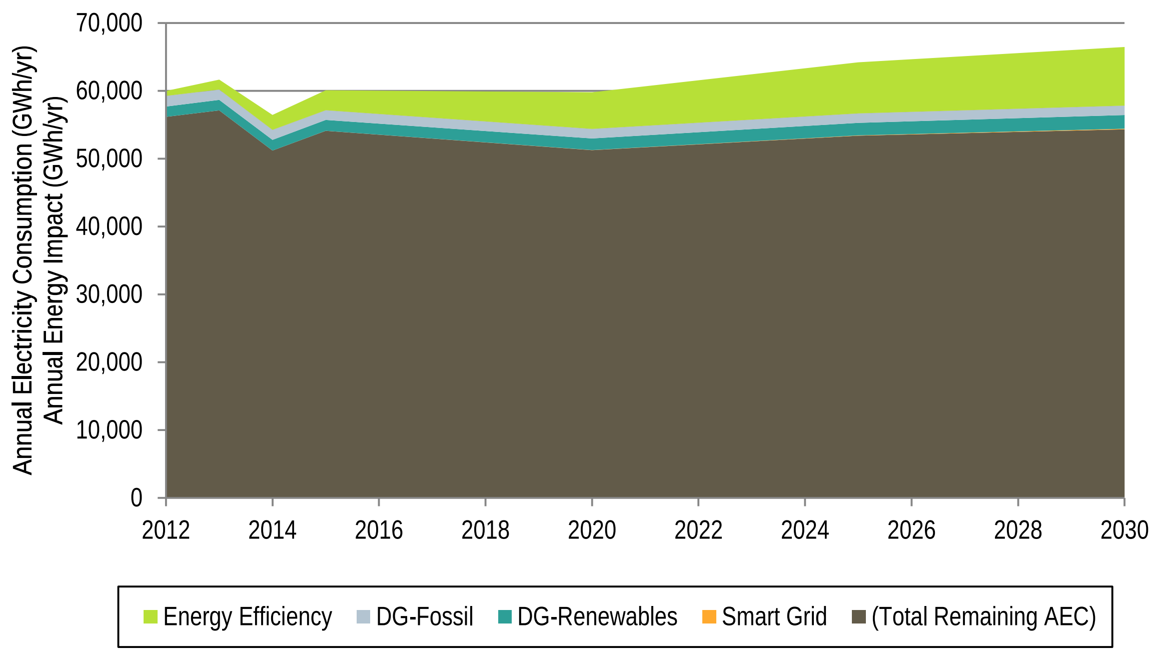
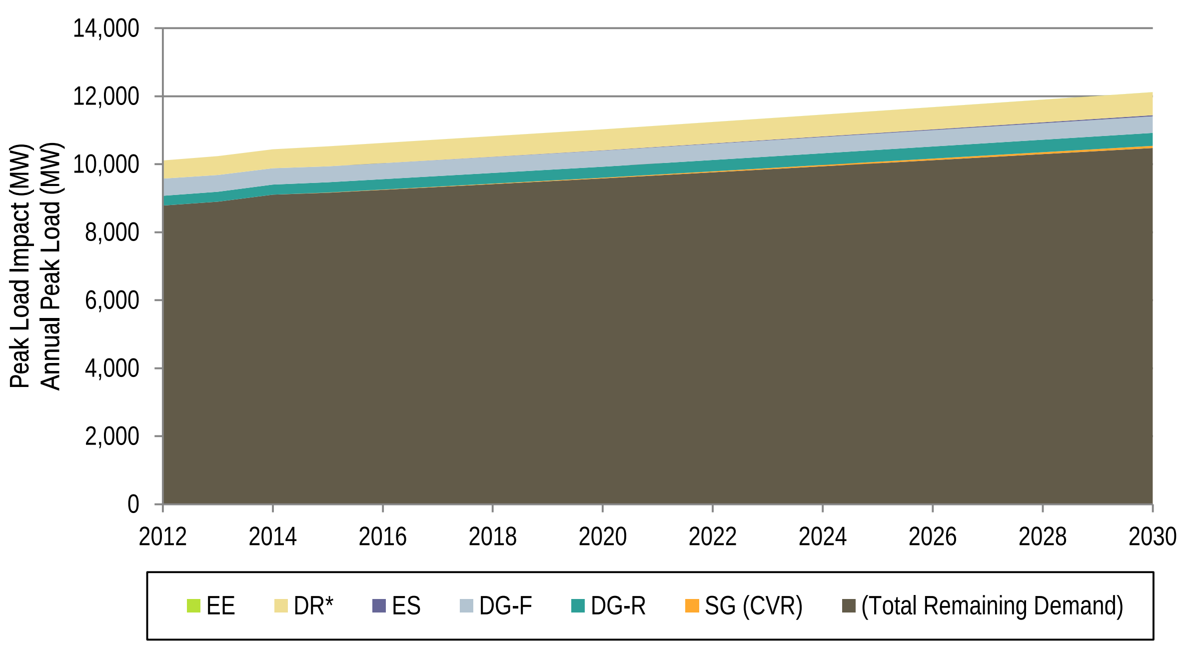


Table A-120. Projected Demand-Side Resource Peak Load Impact in Wisconsin through 2030, by Resource Category

Resource Category	Projected Total Demand-Side Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Energy Efficiency	0	0	1	1	1	2	2
Demand Response (conventional)	496	515	514	540	515	469	456
Demand Response (smart grid-enabled)*	37	40	43	47	100	176	221
Energy Storage	0	0	0	0	10	20	33
DG-Fossil	506	493	480	468	472	478	487
DG-Renewables	287	292	297	302	323	349	381
Smart Grid (CVR)	0	0	0	7	21	44	64
TOTAL	1,325	1,340	1,334	1,365	1,442	1,539	1,644
Total Annual Peak Load	10,109	10,236	10,437	10,524	11,024	11,566	12,119
% of Peak Load Supported by Demand-Side Resources	13.1%	13.1%	12.8%	13.0%	13.1%	13.3%	13.6%

** Includes time-based rate programs that require AMI meters with two-way communication capability.*

Figure A-120. Projected Demand-Side Resource Peak Load Impact in Wisconsin through 2030



Note: "DR" include both the conventional and smart grid-enabled programs.

Appendix B. Scenario Definitions

B.1 Base Case

The Base Case scenario represents the expected deployment of demand-side resources based on the available market information, and reflects the continuation of current trends and policies with no radical technology changes or breakthroughs. The table below presents the description of each of the market drivers considered for Base Case scenario.

Table B-1. Scenario Driver Descriptions for Base Case Scenario

Driver	Description
Policies Supporting Demand-Side Resources	RPS, EERS and other relevant energy policy targets will continue to develop at the expected pace.
Economic Growth	The output of US economy in terms of GDP increases by 2.5% per year through 2030.
Retail Electricity Price	Remains at the 2012 level for all sectors in real dollars.
Natural Gas Prices	• Retail natural gas price increases by 1.5% per year in real dollars through 2030. • Henry Hub price increases by 3% per year in real dollars through 2030.
Greenhouse Gas Policy/Prices	No viable carbon pricing schemes are established before 2030.
Technology Advancement	No significant breakthroughs in technology advancements that would result in significant reduction in the cost increase the adoption, and/or enhancement in the performance of demand-side resources would occur before 2030.
Customer Acceptance	The portion of utility customers accepting technologies enabling advanced demand-side management strategies (e.g., AMI meters and customer devices) and distributed energy resources increases at the expected pace through 2030.

B.2 Scenario 1

Under this scenario, both the Federal and state governments pursue aggressive energy policy targets. Public support for actions against climate change culminates in a regulation that applies a penalty for greenhouse gas (GHG) emissions. This, paired with growing energy demand as a result of strong and sustained economic growth, results in a continuous rise in energy prices at a faster pace compared to the Base Case. Breakthroughs in advancements of enabling and supporting technologies, as well as widespread customer acceptance of advanced energy management solutions, further fuel the increased adoption of demand-side resources. The table below presents the description of each of the market drivers considered for this scenario.

Table B-2. Scenario Driver Descriptions for Scenario 1

Driver	Description
Policies Supporting Demand-Side Resources	Federal and state government agencies will pursue aggressive RPS, EERS targets beyond the current levels.
Economic Growth	The output of US economy in terms of GDP would increase by 3% per year through 2030 – a 0.5% increase in annual growth rate relative to the Base Case.
Retail Electricity Price	GHG emissions fee and higher demand for energy driven by strong economic growth would increase the electricity price by 35% relative to base case by 2030.
Natural Gas Prices	By 2030, GHG emissions fee and higher demand for energy driven by strong economic growth would: • Increase retail natural gas price by 40% relative to the Base Case, and • Increase Henry Hub price by 25% relative to the Base Case.
Greenhouse Gas Policy/Prices	Some market or regulatory mechanism is in place that results in an emissions fee of $25/ton or an equivalent penalty.
Technology Advancement	By 2030, breakthroughs in technology advancements result in significant reduction in the cost, increase the adoption, and/or enhancement in the performance of demand-side resources, increasing the impact of these resources.
Customer Acceptance	By 2030, demand-side resources and their enabling technologies are broadly accepted by utility customers as a norm, increasing the impact of these resources.

B.3 Scenario 2

Under this scenario, strong and sustained economic growth will lead to increased energy demand above the Base Case. However, the impact of increased demand on energy price is tempered by relaxed energy policy goals in the areas of renewables and energy efficiency resources. The table below presents the description of each of the market drivers considered for this scenario.

Table B-3. Scenario Driver Descriptions for Scenario 2

Driver	Description
Policies Supporting Demand-Side Resources	RPS, EERS targets will be relaxed relative to the current levels.
Economic Growth	The output of US economy in terms of GDP would increase by 3% per year through 2030 – a 0.5% increase in annual growth rate relative to the Base Case.
Retail Electricity Price	Although there is a high demand for energy driven by strong economic growth, the lack of stringent energy policies would lead the retail electricity price to remain at the 2012 level for all sectors in real dollars.
Natural Gas Prices	Higher demand for energy driven by strong economic growth would increase the Henry Hub price by 5% relative to the Base Case by 2030, but the lack of stringent energy policies would lead the retail electricity price to remain at the 2012 level for all sectors in real dollars.
Greenhouse Gas Policy/Prices	No viable carbon pricing schemes are established before 2030.
Technology Advancement	No significant breakthroughs in technology advancements that would result in significant reduction in the cost increase the adoption, and/or enhancement in the performance of demand-side resources would occur before 2030.
Customer Acceptance	The portion of utility customers accepting technologies enabling advanced demand-side management strategies (e.g., AMI meters and customer devices) and distributed energy resources increases at the expected pace through 2030.

B.4 Scenario 3

Under this scenario, the stagnant economy will lead to slower increase in energy demand, but the impact of decreased demand on energy price is counteracted by aggressive Federal and state energy policy targets in the areas of renewables and energy efficiency resources. However, the governments do not expand their efforts into the area of GHG emissions. Under this economic and policy environment, demand-side resources are widely accepted among its stakeholders. The table below presents the description of each of the market drivers considered for this scenario.

Table B-4. Scenario Driver Descriptions for Scenario 3

Driver	Description
Policies Supporting Demand-Side Resources	Federal and state government agencies will pursue aggressive RPS, EERS targets beyond the current levels.
Economic Growth	The output of US economy in terms of GDP would increase by 2% per year through 2030 – a 0.5% decrease in annual growth rate relative to the Base Case.
Retail Electricity Price	Although there is a reduced demand for energy as a result of weak economic growth, aggressive energy policy targets would lead the retail electricity price to remain at the 2012 level for all sectors in real dollars.
Natural Gas Prices	Reduced demand for energy as a result of weak economic growth would decrease the Henry Hub price by 5% relative to the Base Case by 2030, but the aggressive energy policy targets would lead the retail electricity price to remain at the 2012 level for all sectors in real dollars.
Greenhouse Gas Policy/Prices	No viable carbon pricing schemes are established before 2030.
Technology Advancement	No significant breakthroughs in technology advancements that would result in significant reduction in the cost increase the adoption, and/or enhancement in the performance of demand-side resources would occur before 2030.
Customer Acceptance	By 2030, demand-side resources and their enabling technologies are broadly accepted by utility customers as a norm, increasing the impact of these resources.

B.5 Scenario 4

Under this scenario, the stagnant economy will lead to slower increase in energy demand and thus energy prices. Furthermore, relaxed energy policies in the areas of renewables and energy efficiency resources further lowers the energy prices. Stakeholders are not given any incentive to aggressively adopt demand-side resources, and utility customers continue to push back on enabling technologies due to documented and perceived concerns.

Table B-5. Scenario Driver Descriptions for Scenario 4

Driver	Description
Policies Supporting Demand-Side Resources	RPS, EERS targets will be relaxed relative to the current levels.
Economic Growth	The output of US economy in terms of GDP would increase by 2% per year through 2030 – a 0.5% decrease in annual growth rate relative to the Base Case.
Retail Electricity Price	Reduced demand for energy due to weak economic growth would decrease the electricity price by 5% relative to base case by 2030.
Natural Gas Prices	Reduced demand for energy due to weak economic growth would decrease retail natural gas price by 5%, and Henry Hub price by 10% relative to the Base Case by 2030.
Greenhouse Gas Policy/Prices	No viable carbon pricing schemes are established before 2030.
Technology Advancement	No significant breakthroughs in technology advancements that would result in significant reduction in the cost increase the adoption, and/or enhancement in the performance of demand-side resources would occur before 2030.
Customer Acceptance	In 2030, utility customers continue to push back on demand-side resources and enabling technologies due to documented and perceived concerns, including data security, health impacts, technology defects, and economic performance

Appendix C. Demand Response Subcategory Descriptions

Direct Load Control (DLC): A demand response activity by which the program sponsor remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers. Also known as direct control load management.

Economic DR: Dispatchable response to an economic market opportunity, rather than for reliability or because of an emergency in the energy delivery system. Includes demand bidding & buy-back, which allows a demand resource in retail and wholesale markets to offer load reductions at a price, or to identify how much load it is willing to curtail at a specific price. These programs are generally targeted towards medium and large C&I customers.

Emergency/Reliability DR: Dispatchable response to an emergency event (e.g., system constraints and local capacity constraints) or a system contingency in exchange for an incentive or rate discount. Includes interruptible load, load as a capacity resource, and emergency demand response programs, and excludes direct load control. These programs are generally targeted towards medium and large C&I customers.

Time-Based Rates (without AMI): Time-based electricity rate programs where prices for electricity vary over time and different prices are in effect for different hours on different days. For the purpose of this survey, we are interested in the number of customers enrolled in Time-of-Use Pricing, which typically applies to usage over broad blocks of hours (e.g. on-peak=6 hours for summer weekday afternoon; off-peak=all other hours in the summer months) where the price is predetermined and constant

- **Time-of-Use Pricing (TOU)—**typically applies to usage over broad blocks of hours (e.g., on-peak=6 hours for summer weekday afternoon; off-peak= all other hours in the summer months) where the price for each period is predetermined and constant. A TOU program that uses Automated Meter Reading (AMR) is example of TOU with one-way communications.

Time-Based Rates (with AMI): Time-based electricity rate programs where prices for electricity vary over time and different prices are in effect for different hours on different days. For the purpose of this survey, we are interested in the number of customers enrolled in the following programs: Time-of-Use Pricing with AMI meters; Real-Time Pricing; Variable Peak Pricing; Critical Peak Pricing; Critical Peak Rebates; and Pre-Paid Metering.

- **Time-of-Use Pricing (TOU)—**typically applies to usage over broad blocks of hours (e.g., on-peak=6 hours for summer weekday afternoon; off-peak= all other hours in the summer months) where the price for each period is predetermined and constant.
- **Real-Time Pricing (RTP)—**pricing rates generally apply to usage on an hourly basis.
- **Variable Peak Pricing (VPP)—**a hybrid of time-of-use and real-time pricing where the different periods for pricing are defined in advance (e.g., on-peak=6 hours for summer weekday afternoon; off-peak= all other hours in the summer months), but the price established for the on-peak period varies by utility and market conditions.

- **Critical Peak Pricing (CPP)—**when utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical events during a specified time period (e.g., 3 p.m.—6 p.m. on a hot summer weekday), the price for electricity during these time periods is substantially raised. Two variants of this type of rate design exist: one where the time and duration of the price increase are predetermined when events are called and another where the time and duration of the price increase may vary based on the electric grid's need to have loads reduced.
- **Critical Peak Rebate (CPR)—**when utilities observe or anticipate high wholesale market prices or power system emergency conditions, they may call critical events during pre-specified time periods (e.g., 3 p.m.—6 p.m. summer weekday afternoons), the price for electricity during these time periods remains the same, but the customer is refunded at a single, predetermined value for any reduction in consumption relative to what the utility deemed the customer was expected to consume.

Appendix D. Annual Growth Rates of Distributed Generation Resources

D.1 DG-Fossil Annual Growth Rates

State	Year-to-Year Annual Growth Rate of DG-F Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Alabama	1.4%	1.5%	1.5%	3.4%	3.3%	3.3%	1.4%
Arkansas	4.6%	4.4%	4.3%	1.3%	1.3%	1.3%	4.6%
Connecticut	7.4%	14.0%	6.4%	3.6%	3.5%	3.4%	7.4%
District of Columbia	-2.2%	-2.2%	-2.1%	-1.5%	-1.3%	-1.1%	-2.2%
Delaware	-0.7%	-0.7%	-0.7%	-1.7%	-1.7%	-1.7%	-0.7%
Florida	-1.4%	-1.3%	-1.3%	-0.2%	0.1%	0.5%	-1.4%
Georgia	-0.4%	-0.3%	-0.3%	-1.5%	-1.3%	-1.1%	-0.4%
Illinois	-0.2%	-0.2%	-0.1%	-1.1%	-0.1%	2.0%	-0.2%
Indiana	-5.4%	-5.7%	-4.7%	-0.2%	0.0%	0.3%	-5.4%
Iowa	0.0%	-1.8%	-1.8%	0.5%	0.5%	0.5%	0.0%
Kansas	0.7%	0.7%	0.7%	0.6%	0.7%	0.7%	0.7%
Kentucky	-8.4%	-9.2%	-10.1%	-2.5%	-2.5%	-2.4%	-8.4%
Louisiana	2.1%	2.2%	2.2%	3.2%	3.3%	3.5%	2.1%
Maine	-5.7%	-5.9%	-3.9%	0.7%	1.0%	1.4%	-5.7%
Maryland	1.0%	5.0%	1.2%	1.6%	1.8%	1.9%	1.0%
Massachusetts	0.7%	2.5%	0.8%	0.2%	0.7%	1.1%	0.7%
Michigan	-0.2%	-0.2%	-0.2%	0.3%	0.5%	0.6%	-0.2%
Minnesota	-1.1%	-1.1%	-1.0%	0.4%	0.7%	0.8%	-1.1%
Mississippi	-1.3%	-1.3%	-1.2%	-0.2%	-0.3%	-0.4%	-1.3%
Missouri	-0.7%	-0.7%	-0.7%	0.2%	0.4%	0.5%	-0.7%
Montana	-0.2%	-0.2%	-0.2%	0.6%	0.5%	0.4%	-0.2%
Nebraska	-0.6%	-0.6%	-0.6%	0.6%	0.6%	0.6%	-0.6%
New Hampshire	-1.4%	-1.4%	-1.5%	1.0%	1.2%	1.4%	-1.4%
New Jersey	0.3%	0.4%	0.5%	1.7%	2.0%	2.1%	0.3%
New Mexico	16.7%	14.3%	12.5%	3.5%	2.9%	2.6%	16.7%
New York	0.8%	1.5%	1.9%	1.2%	1.5%	1.8%	0.8%
North Carolina	-0.8%	-0.5%	-0.4%	-0.3%	-0.2%	-0.1%	-0.8%
North Dakota	1.1%	1.1%	1.1%	0.1%	0.3%	0.4%	1.1%
Ohio	-2.9%	-2.9%	-3.0%	0.5%	1.2%	1.3%	-2.9%
Oklahoma	-7.1%	-7.6%	-8.3%	-3.5%	-4.2%	-3.4%	-7.1%
Pennsylvania	-1.3%	-1.3%	-0.8%	-1.1%	-1.0%	-0.9%	-1.3%
Rhode Island	2.4%	2.4%	2.4%	4.9%	4.4%	4.1%	2.4%
South Carolina	-5.0%	-3.3%	-2.5%	-0.9%	-0.8%	-0.5%	-5.0%
South Dakota	-0.7%	-0.6%	-0.6%	0.8%	0.7%	0.7%	-0.7%
Tennessee	1.5%	1.5%	1.5%	1.8%	1.9%	1.9%	1.5%
Texas	-2.5%	-2.4%	-0.4%	3.3%	4.2%	4.0%	-2.5%
Vermont	-2.0%	-2.0%	-1.9%	-1.6%	-1.4%	-1.2%	-2.0%
Virginia	-2.6%	-1.5%	-1.5%	0.4%	0.5%	0.6%	-2.6%
West Virginia	1.1%	1.1%	1.1%	1.2%	1.3%	1.4%	1.1%
Wisconsin	-2.5%	-2.5%	-2.6%	0.2%	0.3%	0.4%	-2.5%

D.2 Solar PV Annual Growth Rates

Navigant estimated the growth trajectory of distributed solar PV based on the expert review of publicly available sources. The table below presents the state-level annual growth rates of solar PV resource capacity based on the methodology described in Section 3.5.2.

State	Year-to-Year Annual Growth Rate of Solar PV Resource Capacity (MW)						
	2012	2013	2014	2015	2020	2025	2030
Alabama	15.3%	12.6%	10.7%	7.6%	5.2%	4.0%	15.3%
Arkansas	7.6%	6.8%	6.0%	4.7%	3.6%	2.9%	7.6%
Connecticut	19.9%	18.0%	16.6%	13.0%	8.7%	6.4%	19.9%
District of Columbia	43.2%	32.8%	27.0%	17.8%	10.3%	7.2%	43.2%
Delaware	53.5%	39.7%	32.6%	21.3%	11.8%	8.2%	53.5%
Florida	37.7%	33.7%	31.4%	23.7%	13.8%	9.6%	37.7%
Georgia	49.8%	37.1%	30.4%	20.0%	11.3%	7.9%	49.8%
Illinois	4.1%	3.9%	3.7%	3.3%	2.8%	2.5%	4.1%
Indiana	47.6%	33.0%	25.4%	15.5%	8.9%	6.2%	47.6%
Iowa	44.0%	29.0%	21.4%	12.5%	7.2%	5.1%	44.0%
Kansas	46.3%	30.6%	22.6%	13.2%	7.6%	5.4%	46.3%
Kentucky	50.1%	34.2%	26.1%	15.8%	9.0%	6.3%	50.1%
Louisiana	58.1%	41.1%	32.7%	20.7%	11.4%	7.9%	58.1%
Maine	41.8%	29.3%	22.6%	13.8%	8.1%	5.7%	41.8%
Maryland	56.9%	45.2%	39.3%	27.1%	14.7%	10.1%	56.9%
Massachusetts	47.4%	41.0%	37.6%	27.4%	15.1%	10.5%	47.4%
Michigan	46.5%	34.4%	27.8%	17.9%	10.3%	7.2%	46.5%
Minnesota	20.1%	16.8%	14.5%	10.3%	6.8%	5.1%	20.1%
Mississippi	32.0%	23.6%	18.6%	11.8%	7.2%	5.2%	32.0%
Missouri	39.7%	28.6%	22.4%	14.0%	8.2%	5.8%	39.7%
Montana	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Nebraska	23.0%	17.8%	14.4%	9.5%	6.0%	4.5%	23.0%
New Hampshire	26.3%	20.9%	17.3%	11.7%	7.4%	5.4%	26.3%
New Jersey	43.3%	34.0%	28.7%	19.3%	11.0%	7.7%	43.3%
New Mexico	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
New York	55.8%	43.0%	36.4%	24.3%	13.3%	9.1%	55.8%
North Carolina	50.2%	39.6%	33.8%	22.9%	12.7%	8.8%	50.2%
North Dakota	40.1%	26.8%	19.7%	11.5%	6.7%	4.8%	40.1%
Ohio	41.9%	32.8%	27.5%	18.5%	10.7%	7.5%	41.9%
Oklahoma	46.3%	30.6%	22.6%	13.2%	7.6%	5.4%	46.3%
Pennsylvania	57.2%	48.8%	44.8%	32.0%	16.9%	11.5%	57.2%
Rhode Island	32.2%	23.8%	18.8%	11.9%	7.2%	5.2%	32.2%
South Carolina	53.0%	36.8%	28.6%	17.7%	10.0%	6.9%	53.0%
South Dakota	40.1%	26.8%	19.7%	11.5%	6.7%	4.8%	40.1%
Tennessee	52.7%	39.1%	31.9%	20.8%	11.6%	8.0%	52.7%
Texas	42.8%	32.7%	27.0%	17.9%	10.4%	7.3%	42.8%
Vermont	49.3%	36.3%	29.4%	19.0%	10.8%	7.5%	49.3%
Virginia	27.9%	22.1%	18.3%	12.4%	7.7%	5.6%	27.9%
West Virginia	48.8%	32.4%	24.2%	14.3%	8.2%	5.7%	48.8%
Wisconsin	25.8%	21.2%	18.0%	12.6%	7.9%	5.8%	25.8%