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Section 3
Forecasts of New England's Peak Demand, Annual Use of Electric Energy, Energy Efficiency, and Distributed Generation

Load forecasts provide key inputs for evaluating the reliability and economic performance of the electric power system under various conditions and for determining whether and when improvements are needed. This section summarizes the forecasts for the annual use of electric energy and peak loads, New England-wide and in individual states and subareas. It also describes the economic and demographic factors that drive the forecasts and explains the forecasting methodology. For RSP14, the underlying methodology for forecasting annual energy use and peak loads has not changed from RSP13.

Additionally, the section provides the results of the ISO's regional energy-efficiency (EE) forecast for the 10-year RSP planning horizon. The 2014 EE forecast reduces the peak load and net energy consumption forecasts for New England. The region's efforts to develop a distributed generation forecast and the results of a forecast of regional and state-by-state photovoltaic capability also are discussed.

3.1 ISO New England Load Forecasts

The ISO load forecasts are estimates of the amount of electric energy the New England states will need annually and during seasonal peak hours. This year's forecast horizon runs from 2014 through winter 2023/2024. Each forecast cycle updates the data for the region's historical annual use of electric energy and peak loads by adding another year of data to the sample, incorporating the most recent economic and demographic forecasts, and making adjustments for resettlement that include meter corrections.[98]

Table 3-1 summarizes the ISO's forecasts of annual electric energy use and seasonal peak load (50/50 and 90/10) for New England overall and for each state.[99] RSP14 forecasts of annual energy use, and both summer and winter seasonal peak conditions are similar to those published in RSP13.[100] Compared with the RSP13 forecast, the RSP14 50/50 load forecast for summer peak demand is 125 MW lower in 2014 and 205 MW lower in 2022.

[98] The ISO's *Capacity, Energy, Load, and Transmission* (CELT) Reports and associated documentation contain more details on the short-run and long-run forecast methodologies, models, and inputs; weather normalization; regional, state, subarea, and load-zone forecasts of annual electric energy use and peak loads; high- and low-forecast bandwidths; and retail electricity prices. They are available at the "CELT Reports," webpage, http://www.iso-ne.com/system-planning/system-plans-studies/celt. Also see the 2014 CELT Report (http://www.iso-ne.com/static-assets/documents/trans/celt/report/2014/2014_celt_report_rev.pdf) and the *ISO NE Seasonal Peaks since 1980* (April 22, 2014), which can be accessed at the "Energy, Load, and Demand Reports," webpage, http://www.iso-ne.com/isoexpress/web/reports/load-and-demand/-/tree/net-ener-peak-load.

[99] The 50/50 "reference" case peak loads have a 50% chance of being exceeded because of weather conditions. For the reference case, the summer peak load is expected to occur at a weighted New England-wide temperature of 90.2°F, and the winter peak load is expected to occur at 7.0°F. The 90/10 "extreme" case peak loads have a 10% chance of being exceeded because of weather. For the extreme case, the summer peak is expected to occur at a temperature of 94.2°F, and the winter peak is expected to occur at a temperature of 1.6°F.

[100] *Preliminary ISO-NE Annual Energy and Seasonal Peak Forecast 2014–2023*, PAC presentation (Preliminary Forecast 2014–2023) (February 19, 2014), http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/feb192014/a7_preliminary_iso_load_forecast_2014_2023.pdf.

Table 3-1
Summary of Annual Electric Energy Use and Peak Demand Forecast for New England and the States, 2014/2015 and 2023/2024

State[a]	Net Energy for Load (1,000 MWh)			Summer Peak Loads (MW)					Winter Peak Loads (MW)				
				50/50		90/10		CAGR[b]	50/50		90/10		CAGR[b]
	2014	2023	CAGR[b]	2014	2023	2014	2023		2014/15	2023/24	2014/15	2023/24	
CT	34,390	37,495	1.0	7,415	8,165	8,100	8,890	1.0	5,725	5,910	5,895	6,080	0.3
ME	12,265	13,175	0.8	2,110	2,315	2,240	2,465	1.1	1,930	1,985	2,020	2,080	0.3
MA	63,875	70,525	1.1	13,060	14,860	14,070	16,000	1.4	10,380	11,040	10,645	11,305	0.7
NH	12,370	13,700	1.1	2,555	2,940	2,745	3,170	1.6	2,055	2,210	2,175	2,330	0.8
RI	8,755	9,455	0.9	1,920	2,150	2,165	2,430	1.3	1,410	1,445	1,450	1,485	0.3
VT	6,730	7,175	0.7	1,100	1,190	1,145	1,240	0.9	1,080	1,145	1,135	1,200	0.6
New England	**138,390**	**151,525**	**1.0**	**28,165**	**31,620**	**30,470**	**34,195**	**1.3**	**22,575**	**23,735**	**23,325**	**24,480**	**0.6**

(a) A variety of factors cause state growth rates to differ from the overall growth rate for New England. For example, Connecticut has the fastest-growing economy in New England, and Maine has the slowest-growing economy in the region.

(b) "CAGR" stands for compound annual growth rate.

Net energy for load (NEL) is the generation output within an area, accounting for electric energy imports from other areas and electric energy exports to other areas.[101] It also accounts for system losses and excludes the electric energy used to operate pumped-storage hydroelectric plants. The compound annual growth rate (CAGR) for the ISO's electric energy use is 1.0% for 2014 through 2023, 1.3% for the summer peak, and 0.6% for the winter peak.[102] The systemwide *load factor* (i.e., the ratio of the average hourly load during a year to peak hourly load) declines over the forecast horizon, from 56.1% in 2014 to 54.7% in 2023 and begins to flatten by the end of forecast.[103]

Figure 3-1 shows a comparison of the ISO's actual summer peak demand (i.e., the load reconstituted to include the megawatt reduction attributable to ISO New England Operating Procedure No. 4 [OP 4], *Action during a Capacity Deficiency*, and FCM passive demand resources) with the 50/50 load forecast and with the 90/10 load forecast.[104] The actual load has been near or has exceeded the 90/10 forecast six

[101] Energy-only generators are considered part of the generation output within the area.

[102] The compound annual growth rate (CAGR) is calculated as follows:

$$\text{Percent CAGR} = \left\{ \left[\left(\frac{\text{Peak in Final Year}}{\text{Peak in Initial Year}} \right)^{\left(\frac{1}{\text{Final Year} - \text{Initial Year}}\right)} - 1 \right] \times 100 \right\}$$

[103] Preliminary Forecast 2014–2023 presentation, slide 22 (http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/feb192014/a7_preliminary_iso_load_forecast_2014_2023.pdf).

[104] OP 4 actions implemented during a capacity deficiency include Action 2, the dispatch of real-time demand resources, and Action 6, the dispatch of real-time emergency generation. Operating Procedure No. 4, *Action during a Capacity Deficiency* (October 5, 2013), http://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op4/op4_rto_final.pdf.

times over the last 22 years because of hot and humid weather conditions, and it has been near or above the 50/50 forecast 11 times during the same period.[105]

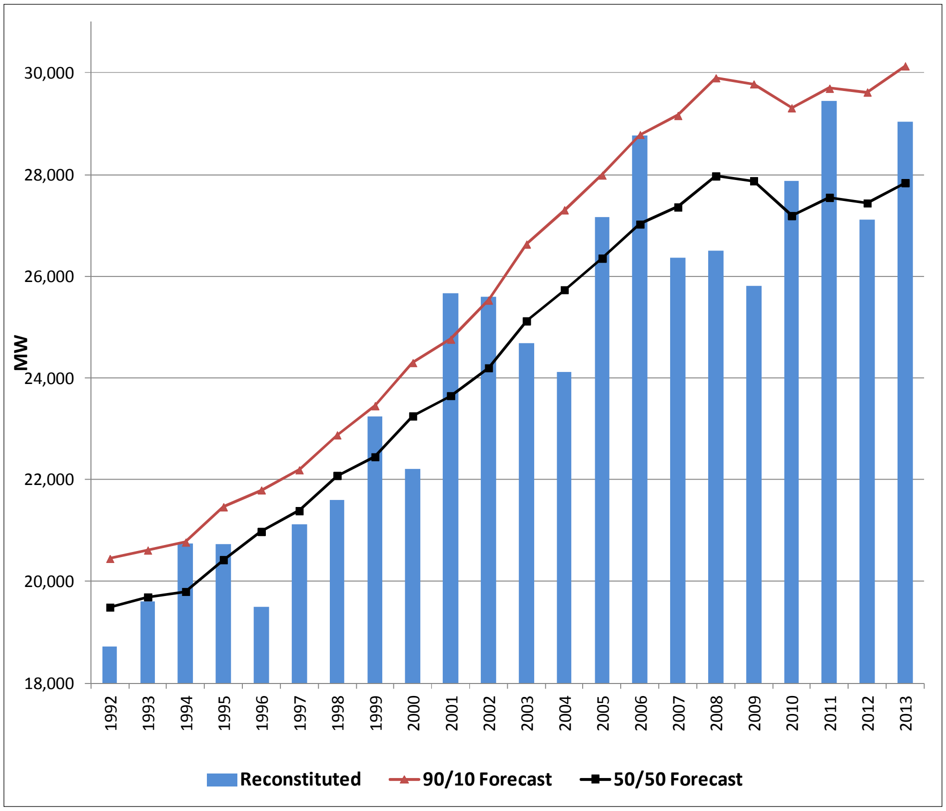

Figure 3-1: The ISO's actual summer peak loads (i.e., reconstituted for OP 4 and FCM passive demand resources) and the 50/50 and 90/10 forecasts, 1992 to 2013 (MW).

Note: The forecasted load values are the first-year values of the CELT forecast for each year. For example, the forecasted loads for 2013 are the loads for the first year of the 2013 CELT Report.

3.1.1 Economic and Demographic Factors and Electric Energy Use

The price of electricity and other economic and demographic factors drive the annual consumption of electric energy and the growth of the seasonal peak. In addition to net energy for load, the forecasts account for the effects of future federal long-term energy-efficiency goals, as well as the historical effects of energy efficiency, but they do not reflect the peak and electric energy savings attributable to passive demand resources in the FCM market and the future EE forecast (see Section 3.1.2). Similarly, the forecast of annual consumption and growth of the seasonal peak considers existing distributed generation not otherwise counted as a resource.

The ISO's forecasts of electric energy use in New England and each state are based on a total energy-use concept, which sums the amount of electric energy used residentially (about 39%), commercially (about 38%), and industrially (about 23%). Real gross state product (RGSP) serves as a proxy for overall

[105] Weather conditions during the actual peak summer loads were slightly below the expected 90/10 weather conditions for 1994, 1999, 2001, and 2002, and weather conditions were slightly above the expected 90/10 weather during the 2006, 2011, and 2014 peaks. A spreadsheet containing historical annual peak loads and associated weather conditions since 1980 is available at http://www.iso-ne.com/markets/hstdata/rpts/ann_seasonal_pks/seasonal_peak_data_summary.xls.

economic and demographic conditions. This variable is the primary force driving the model of electric energy use. Table 3-2 summarizes these and other indicators of the New England economy.

Table 3-2
New England Economic and Demographic Forecast Summary

Factor	1980	2013	CAGR	2014	2023	CAGR
Summer peak (MW)	14,539	27,835	2.0	28,165	31,620	1.3
Net energy for load (1,000 MWh)	82,927	137,193	1.5	138,390	151,525	1.0
Population (thousands)	12,404	14,616	0.5	14,659	14,964	0.2
Real price of electricity (¢/kWh, 2013$)[(a)]	17.901	14.431	−0.7	14.431	14.431	0.0
Employment (thousands)	5,483	6,987	0.7	7,070	7,450	0.6
Real income (millions, 2005 $)	298,071	744,927	2.8	776,146	963,640	2.4
Real gross state product (millions, 2005 $)	310,370	737,680	2.7	759,890	933,624	2.3
Energy per household (MWh)	18.860	23.824	0.7	23.847	24.722	0.4
Real income per household (thousands) (2005 base year)	67.789	129.356	2.0	133.745	157.221	1.8

(a) The forecast of the retail electricity prices assumes that the nominal price of electricity will grow at the rate of inflation (or with flat real prices from 2013 to 2023) and fully incorporate the capacity costs from the Forward Capacity Market. “kWh” stands for kilowatt-hour.

The *Economy.com* November 2013 economic forecast of real gross state product was used to represent overall economic activity in the RSP14 forecast models. Compared with the November 2012 *Economy.com* economic forecast, the November 2013 *Economy.com* forecast of real gross state product shows slower growth from 2011 through 2014, higher growth in 2015, and similar growth for the remaining years.[106] Both forecasts show a slow recovery from the recession, which affects the load forecast. Figure 3-2 compares the RGSP forecasts from November 2013 with those from November 2012.[107]

[106] Economy.com forecasts of New England gross state product (millions of 2005 $) from November 2012 and November 2013 forecasts.

[107] Preliminary Forecast 2014–2023 presentation, slide 14 (http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/feb192014/a7_preliminary_iso_load_forecast_2014_2023.pdf).

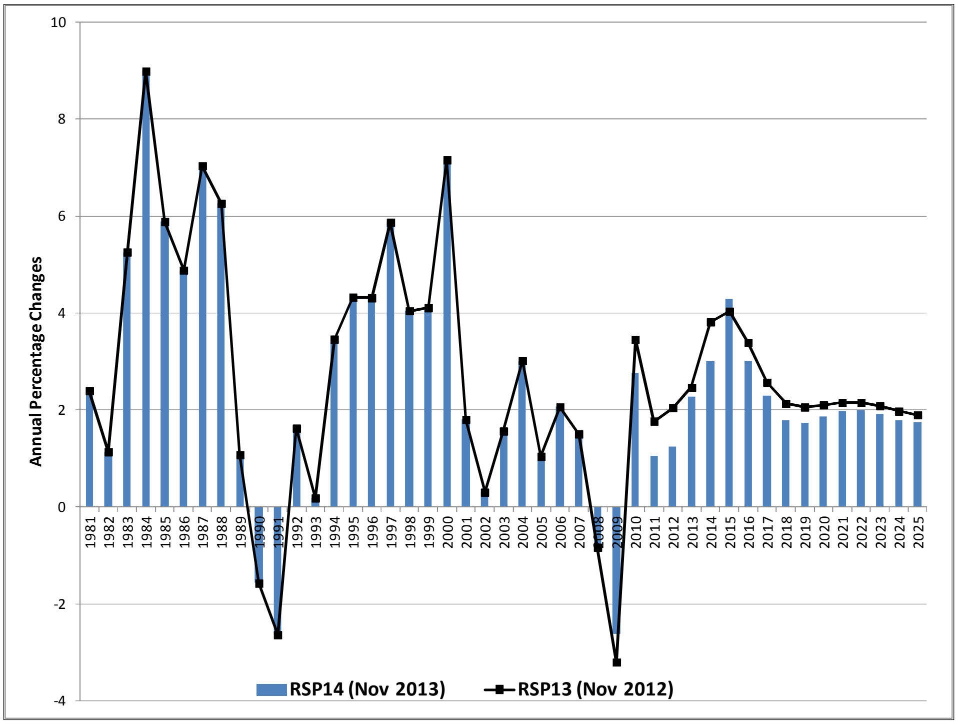

Figure 3-2: "Economy.com" forecasts of New England gross state product from November 2013 and November 2012 forecasts.

Source: Moody's Analytics, Economy.com.
Notes: Years 1981 to 2013 reflect actual gross state product. Note the Bureau of Economic Analysis (of the US Department of Commerce) revisions to the historical data for 2007 to 2013.

3.1.2 The CELT Forecast and Passive Demand Resources

The seasonal peak load and energy-use forecast, as published in the *2014–2023 Forecast Report of Capacity, Energy, Loads, and Transmission* (2014 CELT Report) and used for calculating the Installed Capacity Requirement (ICR), fully accounts for historical energy efficiency, passive demand resources, and future federal appliance standards.[108] The forecast does not expressly reflect the future reduction in peak demand and energy use that will result from the passive demand resources that clear the Forward Capacity Auctions. Similarly, the energy-efficiency forecast (described in Section 3.2) is a separate forecast that is not included as part of the peak load and energy-use forecast. Historical reductions in load from "other demand resources" (ODRs) in the transition period leading up to the FCM and from the

[108] 2014 CELT Report (May 2014), http://www.iso-ne.com/static-assets/documents/trans/celt/report/2014/2014_celt_report_rev.pdf. Copies of all CELT reports are available at http://www.iso-ne.com/system-planning/system-plans-studies/celt. The ICR is the amount of capacity the New England region will need in a particular year to meet its NPCC resource adequacy planning criteria; see Section 4 for additional information. The ISO's *Forecast Data 2014* (April 30, 2014), worksheet 9 (http://www.iso-ne.com/static-assets/documents/trans/celt/fsct_detail/2014/isone_fcst_data_2014.xls) shows that the gross consumption of electric energy for 2023 is 151,525, gigawatt-hours (GWh). The savings attributable to federal appliance standards is 2,506 GWh for 2023. In addition, passive demand resources are projected to save 20,967 GWh for 2023 (see worksheet 2).

passive demand resources in the FCM have been added back into the historical loads used for load forecasting.[109]

3.1.3 Subarea Use of Electric Energy

Much of the RSP14 reliability and production cost analysis depends on the forecasts of annual electric energy use and peak demand in the subareas. Table 3-3 summarizes these forecasts and provides important market information to stakeholders.[110] Table 3-4 shows the forecast for the RSP subareas and their relationship to the load zones and states.[111] The forecasts for the peak demand and annual energy use in the subareas are derived by first allocating the ISO's state forecasts to distribution companies within the states on the basis of historical shares; second, allocating the distribution company forecasts to busses using the ISO model of the transmission network; and finally, aggregating the busses for each of the subareas.

[109] *Other demand resources*, an asset category that was retired on May 31, 2010, at the end of the transition period leading to the FCM, consisted of energy-efficiency measures, load management, and distributed generation—typically nondispatchable resources that tend to reduce end-use demand on the electricity network across many hours but usually not in direct response to changing hourly wholesale prices. For additional information on ODRs, refer to AMR10, Section 2.7, http://www.iso-ne.com/static-assets/documents/markets/mkt_anlys_rpts/annl_mkt_rpts/2010/amr10_final_060311.pdf.

[110] Forecasts of net energy for load and peak loads are "gross loads." Additional details of the loads are available using the "CELT Forecast Details" document-type filter at http://www.iso-ne.com/system-planning/system-plans-studies/celt. Also see the full 2014 CELT Report (http://www.iso-ne.com/static-assets/documents/trans/celt/report/2014/2014_celt_report_rev.pdf).

[111] For additional information, refer to the ISO's pricing node tables at http://www.iso-ne.com/stlmnts/stlmnt_mod_info/index.html.

Table 3-3
Forecasts of Annual Use of Electric Energy and Peak Demand in RSP Subareas, 2014 and 2023

Area	Net Energy for Load (1,000 MWh)			Summer Peak Loads (MW)					Winter Peak Loads (MW)				
				50/50 Load		90/10 Load			50/50 Load		90/10 Load		
	2014	2023	CAGR	2014	2023	2014	2023	CAGR	2014/15	2023/24	2014/15	2023/24	CAGR
BHE	1,785	1,915	0.8	305	335	325	360	1.1	280	290	295	305	0.4
ME	5,775	6,210	0.8	950	1,040	1,010	1,110	1.1	950	975	995	1,025	0.3
SME	4,380	4,710	0.8	785	865	830	920	1.2	660	680	690	710	0.3
NH	10,595	11,625	1.0	2,170	2,470	2,330	2,665	1.5	1,750	1,865	1,850	1,970	0.7
VT	7,850	8,520	0.9	1,355	1,505	1,425	1,585	1.2	1,270	1,360	1,335	1,430	0.8
BOSTON	28,845	31,960	1.1	5,905	6,745	6,360	7,260	1.5	4,685	5,000	4,805	5,120	0.7
CMA/NEMA	8,445	9,095	0.8	1,710	1,895	1,840	2,040	1.2	1,385	1,445	1,420	1,480	0.5
WMA	10,850	11,890	1.0	2,155	2,440	2,320	2,630	1.4	1,810	1,905	1,855	1,950	0.6
SEMA	14,225	15,495	1.0	2,975	3,360	3,215	3,630	1.4	2,260	2,360	2,320	2,420	0.5
RI	11,705	13,130	1.3	2,535	2,910	2,815	3,240	1.6	1,880	2,025	1,935	2,080	0.8
CT	16,410	18,215	1.2	3,540	3,970	3,865	4,320	1.2	2,735	2,870	2,820	2,950	0.5
SWCT	11,085	12,195	1.1	2,390	2,655	2,610	2,890	1.1	1,850	1,925	1,905	1,980	0.4
NOR	6,440	6,570	0.2	1,390	1,430	1,515	1,560	0.3	1,065	1,035	1,095	1,065	−0.3
ISO total[a, b]	138,390	151,525	1.0	28,165	31,620	30,470	34,195	1.3	22,575	23,735	23,325	24,480	0.6

(a) The total load-zone projections are similar to the state load projections and are available at the ISO's "2014 Forecast Data File," http://www.iso-ne.com/static-assets/documents/trans/celt/fsct_detail/2014/isone_fcst_data_2014.xls; tab #2, "ISO-NE Control Area, States, Regional System Plan (RSP14) Subareas, and SMD (Standard Market Design) Load Zones Energy and Seasonal Peak-Load Forecast."

(b) Totals may not equal the sum because of rounding and may not exactly match the results for other tables in this section.

Table 3-4
Forecasts of RSP Subarea Peak Demand, 2014[(a)]

RSP Subarea	Load Zone	State	50/50 Summer Peak Load			90/10 Summer Peak Load		
			MW	% of RSP Subarea	% of State	MW	% of RSP Subarea	% of State
BHE	ME	Maine	305.0	99.7	14.5	325.0	100.1	14.5
ME	ME	Maine	950.0	99.9	45.0	1,010.0	100.1	45.1
SME	ME	Maine	785.0	100.1	37.2	830.0	99.7	37.1
NH	ME	Maine	70.0	3.2	3.3	75.0	3.2	3.3
	NH	New Hampshire	2,060.0	94.9	80.6	2,215.0	95.1	80.7
	VT	Vermont	40.0	1.8	3.6	45.0	1.9	3.9
			2,170			2,330		
VT	NH	New Hampshire	340.0	25.1	13.3	365.0	25.6	13.3
	VT	Vermont	1,020.0	75.2	92.7	1,060.0	74.4	92.6
			1,360			1,425		
BOSTON	NH	New Hampshire	85.0	1.4	3.3	90.0	1.4	3.3
	WCMA	Massachusetts	105.0	1.8	0.8	110.0	1.7	0.8
	NEMA/ Boston	Massachusetts	5,715.0	96.8	43.8	6,160.0	96.9	43.8
			5,905.0			6,360.0		
CMA/NEMA	NH	New Hampshire	70.0	4.1	2.7	80.0	4.3	2.9
	WCMA	Massachusetts	1,640.0	95.9	12.6	1,765.0	95.8	12.5
			1,710			1,845		
WMA	VT	Vermont	40.0	1.9	3.6	45.0	1.9	3.9
	CT	Connecticut	100.0	4.6	1.3	105.0	4.5	1.3
	WCMA	Massachusetts	2,015.0	93.6	15.4	2,170.0	93.5	15.4
			2,155			2,320		
SEMA	RI	Rhode Island	185.0	6.2	9.6	210.0	6.5	9.7
	SEMA	Massachusetts	2,790.0	93.8	21.4	3,005.0	93.5	21.4
			2,975			3,215		
RI	RI	Rhode Island	1,735.0	68.5	90.4	1,955.0	69.4	90.3
	SEMA	Massachusetts	800.0	31.6	6.1	860.0	30.5	6.1
			2,535			2,815		
CT	CT	Connecticut	3,540.0	100.0	47.7	3,865.0	100.0	47.7
SWCT	CT	Connecticut	2,390.0	100.0	32.2	2,610.0	100.0	32.2
NOR	CT	Connecticut	1,390.0	100.1	18.7	1,515.0	99.9	18.7

(a) Totals may not equal the sum because of rounding and may not exactly match the results for other tables in this section.

3.2 Energy-Efficiency Forecast for New England

The FCM provides the ISO with a comprehensive understanding of the savings in energy use over the FCM horizon. Since 2009, the ISO also has been analyzing energy-efficiency programs and studying how to model incremental, future EE savings for periods five to 10 years beyond the FCM horizon. This deliberate and analytic effort advanced the ISO's understanding of energy efficiency from anecdotal to empirical. The result was the nation's first regional (multistate) long-term forecast of energy efficiency. The ISO's regional energy-efficiency forecast, as summarized in this section for 2018 through 2023, is part of ongoing efforts to collect and analyze data in support of the long-term impacts of state-sponsored energy-efficiency programs on future demand.[112]

The final EE forecast for 2018 to 2023 projects savings in the average, total, and peak energy use for the region and each state. The results, which are based on an average annual program spending rate among the six states of more than $900 million per year, show that the regional annual average savings in energy use attributable to new energy-efficiency measures (i.e., not cumulative from EE savings before 2018) is 1,518 gigawatt-hours (GWh). The forecast for the total savings in energy use from the EE projected for 2018 to 2023 is 9,105 GWh. The states' annual average savings in energy use ranges from a low of 68 GWh in New Hampshire to a high of 749 GWh in Massachusetts.

Table 3-5 shows the results of ISO's final EE forecast for 2018 to 2023. The regional average savings in peak demand grows by 205 MW annually. The forecast for total savings in peak demand grows by 1,233 MW from 2018 to 2023. The states' annual average peak savings ranges from a low of 11 MW in New Hampshire to a high of 101 MW in Massachusetts.

[112] State-sponsored EE programs consist of various efforts designed to reduce energy consumption. These efforts generally are funded by multiple sources, including a system benefits charge (SBC) applied to customer bills, the Regional Greenhouse Gas Initiative (RGGI) auction revenues (see Section 6.3.2.4), and state EE policy funds. More information on the methodology used to develop the EE forecast is available at the ISO's "Energy-Efficiency Forecast Working Group," webpage, http://www.iso-ne.com/committees/planning/energy-efficiency-forecast. *ISO New England Energy-Efficiency Forecast Report for 2018 to 2023* (June 3, 2014), http://www.iso-ne.com/static-assets/documents/2014/08/eef_report_2018_2023_final.pdf.

Table 3-5
ISO New England's Final Energy-Efficiency Forecast for 2018 to 2023 (GWh, MW)[a]

Forecast of Electric Energy Savings (GWh)							
Year	Sum of States	States					
		ME	NH	VT	CT	RI	MA
2018	1,764	142	76	125	401	141	880
2019	1,658	132	73	120	379	132	823
2020	1,560	122	69	117	358	123	769
2021	1,462	114	66	110	338	114	719
2022	1,373	106	63	106	319	106	672
2023	1,288	99	60	102	300	99	628
Total	9,105	714	408	681	2,096	715	4,491
Average	**1,518**	**119**	**68**	**113**	**349**	**119**	**749**

Forecast of Peak Demand Savings (MW)							
Year	Sum of States	States					
		ME	NH	VT	CT	RI	MA
2018	239	20	12	18	49	22	118
2019	225	19	12	17	46	20	111
2020	211	17	11	17	44	19	104
2021	198	16	11	16	41	18	97
2022	186	15	10	15	39	16	90
2023	174	14	10	14	37	15	85
Total	1,233	101	66	96	255	111	605
Average	**205**	**17**	**11**	**16**	**42**	**18**	**101**

(a) The forecast results are available at www.iso-ne.com/eefwg.

Individual program administrators and state regulatory agencies provide the ISO with the EE program performance and budget data used to create the forecast. ISO New England's Energy-Efficiency Forecast Working Group assesses the forecast assumptions and offers input.

3.3 Load Forecast Incorporating Results for FCA #8 and the 2014 Energy-Efficiency Forecast

The section presents the load forecast reflecting FCM passive demand resources, including the results of the eighth Forward Capacity Auction (FCA #8) for the 2017/2018 capacity commitment period (CCP) and the 2014 energy-efficiency forecast for 2018–2023. Figure 3-3 and Figure 3-4 show the forecasts of annual energy use and summer peak loads, incorporating FCM-qualified PDRs through 2017 and the EE forecast data for 2018 to 2023.

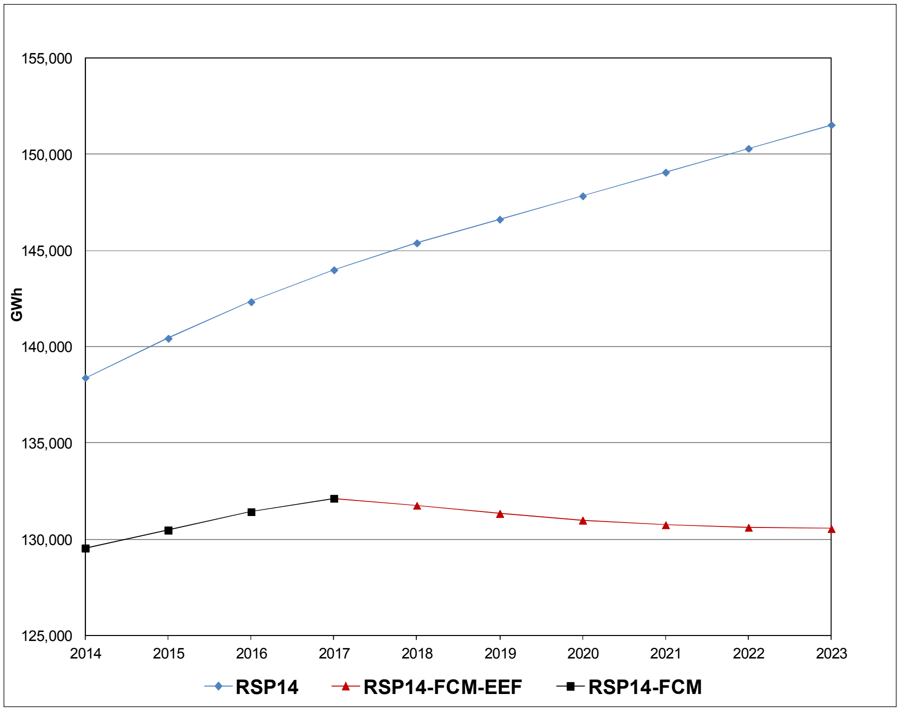

Figure 3-3: RSP14 annual energy-use forecast (diamond), energy-use forecast minus FCM #8 PDRs through 2017 (square), and energy-use forecast minus FCM PDRs and minus the energy-efficiency forecast (triangle) for 2018 to 2023 (GWh).

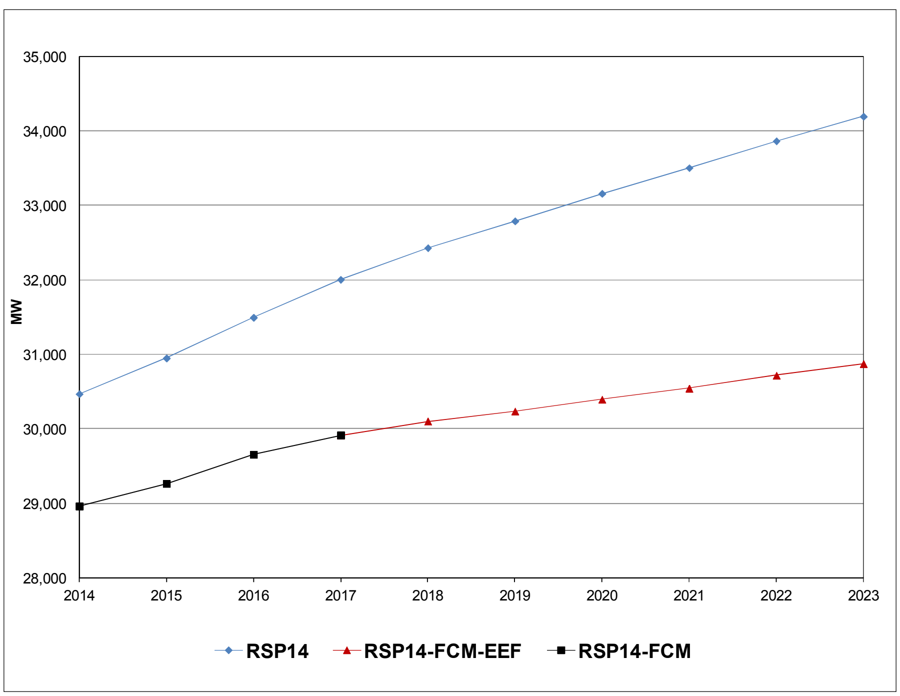

Figure 3-4: RSP14 summer peak demand forecast (90/10) (diamond), demand forecast minus FCM #8 PDRs through 2017 (square), and demand forecast minus FCM PDRs and minus the energy-efficiency forecast (triangle) for 2018 to 2023 (MW).

As shown in Table 3-6, the annual energy-use forecast, minus both the FCM-qualified passive demand resources projected for 2014–2017 and the results of the 2018–2023 energy-efficiency forecast, indicates essentially no long-run growth in electric energy use. The summer peak 90/10 forecast, when adjusted for both the existing FCM-qualified PDRs projected for 2014–2017 and the 2018–2023 energy-efficiency forecast, is projected to increase at a more modest rate, approximately half the projected growth rate of the forecast. The net winter peak is flat (i.e., negative 0.1%) over the 10-year forecast.

Table 3-6
2014 Forecasts of Annual and Peak Electric Energy Use
Compared with the Forecast Minus FCM-Qualified Passive Demand Resources (2014 to 2017)
and Energy-Efficiency Forecast Results (2018 to 2023)

	Gross	Gross – (FCM + EEF)
NEL	1.0	0.1
50/50 and 90/10 Summer	1.3	0.7
50/50 and 90/10 Winter	0.6	−0.1

3.4 Distributed Generation Forecast

Following the success of its energy-efficiency forecast, in 2013 the ISO began to develop a methodology for forecasting the long-term impacts of distributed generation resources in New England. After researching other grid operators' approaches and establishing an open stakeholder process, the ISO developed the nation's first multistate forecast of DG resources 10 years into the future. This section describes the creation and scope of this DG forecast. The section also highlights next steps that may broaden the focus of the DG forecast.

3.4.1 Background

DG resources are growing significantly in New England.[113] Because PV resources constitute the largest segment of DG resources throughout New England, the ISO's analysis of DG and the creation of the first DG forecast focus exclusively on the impact of anticipated DG photovoltaics.[114]

Across the region, PV is being installed at rapidly increasing rates. Data gathered by the ISO indicate that, starting at relatively low levels in recent years, about 250 MW_{AC} of PV was installed in the region by the end of 2012.[115] By the end of 2013, installed nameplate PV jumped to almost 500 MW_{AC}.[116] State policy drives much of this development. For example, Massachusetts reached its 250 MW_{DC} PV goal four years

[113] Since its inception, the ISO has accounted for DG in its resource and load forecasts. Existing and future DG with obligations in the FCM are considered resources and contribute to meeting New England's ICR. Existing non-FCM DG resources registered in the wholesale energy market are counted as "generating load assets" (i.e., settlement-only resources). Load reductions from the remainder of existing DG (i.e., installations that do not participate in the wholesale markets) are embedded in the historic loads used to develop the ISO's 10-year load forecast.

[114] DG can use many technologies, including PV, wind, fuel cells, combined heat and power, and hydroelectric.

[115] The DC nameplate rating of a PV installation is equal to the sum of the ratings of its solar panels, whereas its AC nameplate rating is determined by the sum of the rating(s) of its inverter(s).

[116] Generically, the *nameplate* rating is a measure of a piece of equipment's ability to produce or transmit electricity.

early in 2013, and in May 2013, the commonwealth announced an expanded in-state PV goal of developing 1,600 MW_{DC} by 2020.[117]

Almost all PV systems interconnect to the distribution system pursuant to state-jurisdictional interconnection standards.[118] Because the ISO is not directly involved in the interconnection of most of these resources, it has not traditionally been aware of when and where they are installed.

To help address the interrelated questions of exactly how much additional PV is anticipated in the ISO's 10-year planning horizon and what impacts this future PV could have on the regional power grid, the ISO, in conjunction with stakeholders, endeavored to create a forecast of all future PV resources—those that participate in the ISO New England markets as well as those that do not. To assist its development of a DG forecast and provide a forum to discuss DG integration issues, the ISO established the Distributed Generation Forecast Working Group (DGFWG) open to all interested parties.[119] State agency representatives with strong knowledge of DG programs, as well as electric power distribution companies and DG program administrators, play a key role in the DGFWG.[120] The DGFWG's work and other stakeholder group contributions will build on and contribute to other ISO efforts to address these challenges.

3.4.2 Development of a PV Forecast Methodology

The creation of a PV forecast is exceptionally complicated. The viability of PV development depends on a complex interaction between both public policy and private investment. The unknown future costs of PV and advances in its technology create additional uncertainties affecting the potential and realizable amounts of PV development. Further, as an intermittent resource (i.e., subject to variations in "fuel" determined by weather), the seasonal and diurnal fluctuations of the solar resource are important considerations. Therefore, the amounts, timing, performance characteristics, and geographic distribution of future PV development are all factors that must be considered in a PV forecast. Working through the DGFWG, the ISO determined that its first step would be to develop a qualitative DG forecast focusing exclusively on PV. Moreover, because of the noted complexities, the PV forecast would be limited to PV that results from New England state policies.

3.4.3 Data Collection

The first step in developing the PV forecast was the compilation of information on state PV policy goals as a part of the states' objectives for developing renewable resources. To this end, the ISO surveyed states

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[117] Of the DC electricity PV panels generate, 83% is converted into AC electricity, which is commonly used by utility customers.

[118] State-jurisdictional standards are typically applicable for all solar projects, including both "rooftop" and MW-scale solar "farms." New England presently does not include any FERC-jurisdictional PV project (~500 MW total); however, two projects currently in the ISO New England Generation Interconnection Queue (the queue) seeking interconnection may be FERC-jurisdictional and would need to meet the ISO's small generator interconnection procedures (SGIP) or Small Generator Interconnection Agreement (SGIA) or both. See the OATT, Schedule 23, "Small Generator Interconnection Procedures" (July 25, 2012), http://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/sch23/sch_23_sgip.pdf.

[119] The DGFWG is chaired by a representative of ISO New England and is not a formal NEPOOL committee or subcommittee. More information on the DGFWG, including the group's scope of work (September 25, 2013) is available at http://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/othr/distributed_generation_frcst/2013mtrls/sep302013/draft_dgfwg_scope_of_work.pdf.

[120] The DGFWG initial meeting provided an opportunity for the states to update the ISO on the breadth of their DG programs.

for details on their specific PV policies, as well as distribution utilities to identify existing amounts of PV resources and those in the ISO Generator Interconnection Queue (the queue).[121]

3.4.4 PV Forecast

The ISO based its PV estimates on the states' policy goals and adjusted the megawatt amounts for various factors, including a DC-to-AC nameplate conversion rate (where appropriate) and the application of the tariff-driven summer seasonal claimed capability (SSCC) factor.[122] Importantly, because most states do not have PV-focused policies that extend through the ISO's 10-year forecast horizon, the ISO assumed that PV would be installed at a constant rate equal to the last available policy year. However, because of significant uncertainty regarding how much PV existing and future PV policies will ultimately support, the ISO-applied discount factors to the PV estimates. The discount factors are in addition to the above-noted adjustment factors.[123]

In general, discount factors are applied to forecast values of policy-supported megawatts of PV, are applied equally in all states, and increase annually—over time, as much as 25%. PV forecasted beyond the existing state program duration is more heavily discounted (75%) because of a much higher degree of uncertainty in forecasting future policy and market/price conditions necessary to support the continued development of PV. Table 3-7 shows the discount factor percentages for state policy-supported megawatts of PV from 2013 to 2023 and for post-policy years for the known policy years.[124] The ISO applied these discount rates to the future projections of PV growth in New England.

Table 3-7
Discount Factor Percentages for New England State Policy-Supported Megawatts of PV, 2013 to 2023 and Post-Policy Years

Policy-Based MW Percentage											Post-Policy MW %
Through 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
0%, but utility data must confirm	10%	15%	20%	25%	25%	25%	25%	25%	25%	25%	75%

Table 3-8 lists the state-by-state annual and cumulative PV nameplate capacities, after applying discount factors, forecast through the 10-year planning horizon. These projections include all existing and future PV in the FCM, as well as PV that does and does not participate in the ISO's wholesale energy markets and that reduces the load the ISO observes. The table also lists the corresponding total estimated summer

[121] State PV policy data presented to the DGFWG is available at the ISO's "Distributed Generation Forecast" webpage, http://www.iso-ne.com/system-planning/system-forecasting/distributed-generation-forecast. The *ISO's Generator Interconnection Queue* includes the requests submitted by generators to interconnect to the ISO New England-administered transmission system; see Section 4.5.2.

[122] *Seasonal claimed capability* is a generator's maximum production or output during a particular season, adjusted for physical and regulatory limitations.

[123] A full explanation of the various discount factors and other modeling assumptions is contained in *Discussion of PV Performance and ISO's Draft Interim PV Forecast*, DGFWG presentation (December 16, 2013), http://www.iso-ne.com/committees/comm_wkgrps/othr/distributed_generation_frcst/2013mtrls/dec162013/dg_forecast.pdf.

[124] The policies differ for each state, and they have different end years. A discount of 25% was applied to the state goals for each of the policy years shown in the table. The megawatt growth beyond the last known policy year is considered constant, but a discount factor of 75% was applied rather than the 25%,

seasonal claimed capability of the annual and cumulative capacities, which assume a 35% AC nameplate-to-SSCC ratio.[125] Solar typically has a zero or negligible winter SCC.

Table 3-8
State-by-State Annual and Cumulative PV Nameplate Capacity Forecast after Applying Discount Factors, 2013 to 2023 (MW_{AC})

States	Annual Total MW (MW, AC nameplate rating)											Totals
	Through 2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	
CT	73.8	46.2	39.3	53.0	34.7	34.7	13.1	13.1	13.1	13.1	11.6	**345.4**
MA	361.6	168.5	117.4	110.5	103.6	98.7	98.7	98.7	32.9	32.9	32.9	**1,256.4**
ME	8.1	2.0	1.9	1.8	1.6	1.6	1.6	1.6	1.6	1.6	1.6	**25.2**
NH	8.2	2.5	2.3	2.2	2.0	2.0	2.0	2.0	2.0	0.7	0.7	**26.7**
RI	10.9	7.3	5.4	3.7	1.2	1.2	1.2	1.2	1.2	1.2	1.2	**35.5**
VT	36.1	20.1	13.4	7.0	6.5	6.5	6.5	6.5	6.5	6.5	1.7	**117.3**
Annual	**498.7**	**246.5**	**179.6**	**178.1**	**149.6**	**144.8**	**123.1**	**123.1**	**57.3**	**56.0**	**49.7**	**1,806.5**
Cumulative	**498.7**	**745.2**	**924.8**	**1,102.9**	**1,252.5**	**1,397.3**	**1,520.4**	**1,643.6**	**1,700.9**	**1,756.9**	**1,806.5**	**1,806.5**
Estimated Summer Seasonal Claimed Capability (MW, based on 35% of AC nameplate rating and assuming winter SCC equals zero)												
Annual Summer SCC	**174.5**	**86.3**	**62.9**	**62.3**	**52.4**	**50.7**	**43.1**	**43.1**	**20.1**	**19.6**	**17.4**	**632.3**
Cumulative Summer SCC	**174.5**	**260.8**	**323.7**	**386.0**	**438.4**	**489.0**	**532.1**	**575.2**	**595.3**	**614.9**	**632.3**	**632.3**

The ISO is participating in several DOE projects and conducting independent work to develop a forecast of PV energy production. Projecting PV energy production is exceedingly complex and must account for advanced technical issues, including the anticipated fluctuations of the electric energy output attributable to the weather and the future performance of these resources due to factors such as actual siting characteristics and the reliability of future system components (e.g., inverters, modules). The ISO plans to review and analyze the actual performance of PV resources and other types of data before generating a PV energy forecast. Plans call for continuing discussions on the PV energy forecast with the DGFWG and releasing an ISO forecast in RSP15.

To gain insights into the process for conducting a full PV energy forecast, the ISO analyzed PV's potential annual energy production for the region using a number of gross assumptions and a weather pattern for 2006. The results showed that a future fleet of 1,800 MW of PV could produce approximately 2,435 GWh in 2023, but the amount of energy production would likely vary because of annual fluctuations of prevailing weather.[126] This estimated annual energy production of approximately 1.6% of the NEL in 2023 is based on the 151,525 GWh net energy for load indicated in Table 3-2 (Section 3.1.1) for that year. Monthly and daily PV energy output will vary more significantly due to weather.

125 Various planning studies may use values that differ from the SSCC, depending on the study assumptions and intent.

126 The annual PV energy output calculation assumes an estimated 15.4% capacity factor on the basis of AC nameplate capacity.

Results of the forecast will inform various ISO system planning functions. For example, the ISO intends to use data from the DG forecast in the following types of analyses:

- Transmission needs assessments
- Transmission solutions studies
- Proposed plan application studies
- System impact studies
- Economic studies

The ISO will work with stakeholders to explore how to use the DG forecast in the above planning analyses and possibly apply it to other market-related assessments.[127] These may include such tasks as the development of the Installed Capacity Requirement. The ISO will require guidance from FERC on a number of ongoing market changes addressing resource adequacy issues (e.g., the demand curve, capacity zones, and pay for performance) before being able to determine the best methods for potentially incorporating the DG forecast into the resource adequacy process. As part of these processes, the ISO will consider the amounts of PV that participate in the FCM and the wholesale energy markets to ensure that each category is treated in accordance with market rules and that resources are not counted more than once.

3.4.5 Next Steps

The ISO will consider how to build on the PV forecast, including the potential of additional DG resources, such as combined heat and power resources.

To conduct planning studies at various geographical levels (e.g., state and load zone levels, dispatch zones, and nodes) that account for existing PV resources, the ISO will need to collect data. Specifically, the ISO will need data on the cumulative installed nameplate capacity over time; cumulative energy production; and an accurate breakdown of total PV that participates in the FCM and wholesale energy markets compared with PV that does not participate in the markets (and serves to reduce load). The ISO has begun to work with the region's distribution utilities to collect this type of data and will continue this effort.[128]

The growth in DG presents some challenges for grid operators and planners. Challenges for the ISO include the following:

- A limited amount of data concerning DG resources, including their size, location, and operational characteristics
- A current inability to observe and control DG resources in real time
- A need to better understand the impacts on system operations of the increasing amounts of DG, including ramping (i.e., rate of starting and stopping), reserve, and regulation requirements

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[127] The ISO will coordinate the use of the DG forecast with the PAC and the appropriate NEPOOL technical committees.

[128] See *Update on DG Location and Modeling Issues*, DGFWG presentation (April 2, 2014), http://www.iso-ne.com/committees/comm_wkgrps/othr/distributed_generation_frcst/2014mtrls/apr22014/dg_location_modeling.pdf.

- Potential impacts to the reliability of the regional power system posed by future amounts of DG resulting from existing state interconnection standards

The ISO's work with the DGFWG will help position the region to best integrate rapidly growing DG resources in a way that maintains reliability and allows the states to realize the public policy benefits they have identified as the basis for their DG programs. Section 6.6 discusses other outstanding issues, including DG interconnection requirements and a short-term operations forecast.

3.5 Summary of Key Findings of the Load, Energy-Efficiency, and PV Forecasts

The RSP14 forecasts of annual net energy use and peak loads are key inputs in establishing the system needs discussed in Section 4 through Section 6. The RSP14 forecasts for the annual use of electric energy and summer and winter peak are essentially the same as in RSP13. The key points of the forecast are as follows:

- The forecasts for annual energy use and the summer and winter peaks are not materially different from the RSP13 forecast.
- The ISO will continue examining ways to improve the load forecast and the energy efficiency forecast.
- The gross compound annual growth rate for the ISO's electric energy use is 1.0% for 2014 through 2023, 1.3% for the summer peak, and 0.6% for the winter peak.
- The annual load forecast minus both the FCM passive demand resources and the ISO EE forecast shows essentially a 0.1% compound annual growth in energy consumption, 0.7% increases in the summer peak load, and 0.1% reductions in the winter peak load.

Through the Distributed Generation Forecast Working Group, the ISO and interested stakeholders have developed a methodology for forecasting New England state policy-supported photovoltaic megawatts and a PV forecast for 2014 to 2023. Ongoing efforts are assessing the potential for broadening the forecast to include other drivers of PV as well as other types of DG resources.