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The value of demand response in Florida

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ABSTRACT

Many electrical loads may be operated flexibly to provide grid services, including peaking capacity, reserves, and load shifting. The authors model 14 demand end uses in Florida and analyze their operational impacts and overall value for a wide range of solar penetrations and grid flexibility options. They find demand response is able to reduce production costs, reduce the number of low-load hours for traditional generators, reduce starting of gas generators, and reduce curtailment.

1. Introduction

Demand response (DR) is a broad descriptor for any electric utility or aggregator program that incentivizes or requires loads to reduce or otherwise modify their energy consumption in support of grid operations. These types of programs have been in use for many years in the United States in the industrial sector, where customers are contracted to reduce their demand during emergency periods. More recently, demand response programs have been used to shift residential and commercial loads away from peak periods. As renewable generation sources increase, the ability of demand response to help mitigate challenges with increased net load variability and uncertainty has become of higher interest to utilities due to its ability to provide flexibility to the electric grid. Additionally, rapidly developing communication and control technologies have made demand response more flexible and easier to implement.

In this article we study the potential impact of demand response in Florida assuming both low and high levels of solar photovoltaic (PV) deployment. Florida currently has a high level of demand response and little PV generation, but the state is poised to see high growth in solar energy in coming years due to its high solar resource potential and the falling costs of solar installations (Gagnon et al., 2016; Lopez et al., 2012; NREL, 2016; Lazard, 2016). Challenges with the "duck curve" that are starting to be seen in California, including low net loads during the day and a steep ramp in net load during the evening, are likely to be seen in Florida as well in the 5- to 15-year timeframe (Hale et al., 2017). Demand response can help mitigate these issues by shifting loads from high net load periods to low net load periods, providing reserves to meet increased variability from solar, and by providing capacity for long-term system planning. This is in addition to the valuable capacity and peak load management services that demand response already provides (Lee et al., 2015).

In this article we analyze the impact on grid operations of 14 different load types that could provide demand response in Florida. We include two demand response penetrations, one approximately equivalent to 2015 participation in demand response programs, and one assuming a high participation rate. We analyze the changing impacts of demand response as PV penetration increases from 5% to 45%, with a focus on the value of demand response to the system at higher penetrations in terms of system operation impacts.

2. Methods

We analyzed the grid operations of the Florida Reliability Coordinating Council (FRCC) using the commercial software package PLEXOS (Energy Exemplar, 2014), and the FRCC model created for (Denholm et al., 2016). In this model, we include all operational constraints on generators and enforce line limits on all lines above 200 kV. It includes a connection to the only reliability region in the eastern interconnection that is electrically connected to FRCC, the SERC Reliability Corporation in Georgia, which is modeled as a single load and supply curve of generation. We include additional utility scale photovoltaic generators to enable penetrations up to 45%. For more information on the PLEXOS model, see (Hale et al., 2017; Denholm et al., 2016).

We incorporate demand response resources for 14 different load end uses into the model of FRCC, dispersing the demand response into the two nodes with the highest load per region. We use hourly estimates of the total potential demand response resource from (Olsen et al., 2013), which uses several filters to calculate the fraction of a load that is

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Table 1
Demand response end-use constraints by sector, including grid services that can be provided.

Sector	End-Use	Grid Services	Load Recovery Restrictions	Balancing Freq. (days)	Daily Duration Restriction (h)
Residential	Cooling	R, C, E	5 am–6 pm	1	1
	Heating	R, C, E	3 am–7 pm	1	1
	Water heating	R, C, E	–	1	–
Commercial	Cooling	R, C, E	5 am–6 pm	1	2
	Heating	R, C, E	3 am–7 pm	1	2
	Ventilation	R, C	–	–	–
	Lighting	R, C	–	–	–
Municipal	Wastewater pumping	E	–	1	3
	Water pumping	E	–	1	2
	Outdoor Lighting	R, C	–	–	–
Industrial	Datacenters	C, E	4 am–8 pm	1	4
	Manufacturing	C, E	–	1	–
	Refrigerated warehouses	E	–	1	4
	Agricultural pumping	C, E	–	7	8

controllable, sheddable, and acceptable to consumers. In this and our companion work we adjust these filters to better represent the current status of demand response (Low DR scenario) and a more realistic future scenario with high DR participation (High DR scenario) (Hale et al., 2017). These data provide an estimate of the total load a particular end use can change in response to a grid signal, including potential contributions to energy shifting and reserves provision. Each end use is subject to different constraints based on assumptions about how much that end use could reasonably be used. These constraints, listed in Table 1, are expanded from similar work done in (Hummon et al., 2013).

These constraints consist of requirements on allowable time ranges for shifting energy, including when load shifting can be recovered based on building occupancy and comfort levels, restrictions on the amount of time a single load may be shifted, and a requirement that a demand response provider may not simultaneously provide reserves and energy shifting for more than its total capacity.

For this work, we analyze a set of scenarios to study the impact of demand response in comparison with or in addition to other measures of flexibility. This includes battery capacities of 1 GW and 4 GW with 6 hours of energy storage, and a set of conditions, called the Flex System, to increase operational flexibility: reducing minimum generation levels of gas combined-cycle (CC) generators, enabling reserves sharing between regions, and allowing PV to provide reserves. The scenario framework can be seen in Fig. 1. Each scenario consists of a particular PV penetration, demand response option, and flexibility option.

3. Results

The traditional role of demand response is to reduce load at peak times, or in times of system emergency, so as to improve system reliability and economic efficiency. The outcomes of the fulfillment of such roles include avoided new capacity builds, and reduced production costs. Production cost savings can accrue from reduced prices in peak times, reduced reserve costs (especially to cover contingencies), and reduced startups and shutdowns of other generators. These types of benefits are summarized both monetarily and from an operational point of view in the first part of this section.

In emerging power systems that include more wind and solar, DR may assume additional roles. In particular for high penetration PV

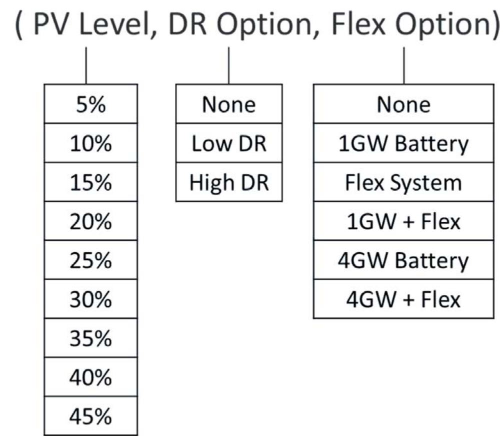

Fig. 1. Scenario framework for the analysis. Each scenario consists of one PV level, one DR option and one flexibility option.

systems, any resource that can potentially shift generation from one time period to another in rhythm with the diurnal cycles of the sun and electricity demand becomes more valuable and can be used to perform this service on days of significant curtailment. Additionally, resources that can quickly increase generation or decrease loads during periods of rapidly changing net-load, such as during the afternoon when solar output decreases and total demand is increasing, can reduce stress on the grid and limit the use of high-cost generators during these times. These roles, and a description of how the presence of battery storage influences DR operations and vice versa, are covered in the second set of results.

3.1. Overall impacts of DR on FRCC

3.1.1. Production costs

The total production cost of serving a region's electricity demand consists of all direct costs incurred through generation, including the fuel costs, variable operation and maintenance costs (VO&M), and start and shutdown costs. This represents the direct costs of operating the electric system modeled. The total production cost of the combined FRCC-SERC system ranged from \$11.6 million to \$14.2 million for different PV penetrations before the addition of any flexibility options, as in Table 2. Increasing PV penetration reduces the production cost due to lower usage of fuel, reducing the overall fuel costs in the system.

Demand response reduces the total production costs in all cases; however, the Low DR scenario does not significantly impact costs at low PV penetrations. Table 2 shows the total reduction in cost for a range of PV penetrations in the base flexibility scenario. The Low DR scenario reduces costs by 0.1% at 5% PV, and by 0.8% at 45% PV. The benefits of the Low DR scenario are more operational in nature, and will be discussed in subsequent sections. The High DR scenario has a higher impact, reducing costs by 0.5% at 5% PV, 1.0% at 25% PV and 2.2% at 45% PV. This is a much more significant impact on the overall costs, in addition to operational changes seen due to DR.

Table 2
Production cost reduction from demand response in the baseline flexibility scenario.

Flexibility Scenario	DR Scenario	Total Production Cost (million \$)				
		5% PV	15% PV	25% PV	35% PV	45% PV
Base	No DR	14,232	13,148	12,372	11,841	11,607
		Reduction in Total Production Cost (million \$) from Base, no DR scenario				
		5% PV	15% PV	25% PV	35% PV	45% PV
Base	Low DR	20.98	31.92	40.60	67.63	95.21
	High DR	76.35	93.43	127.75	181.72	259.15