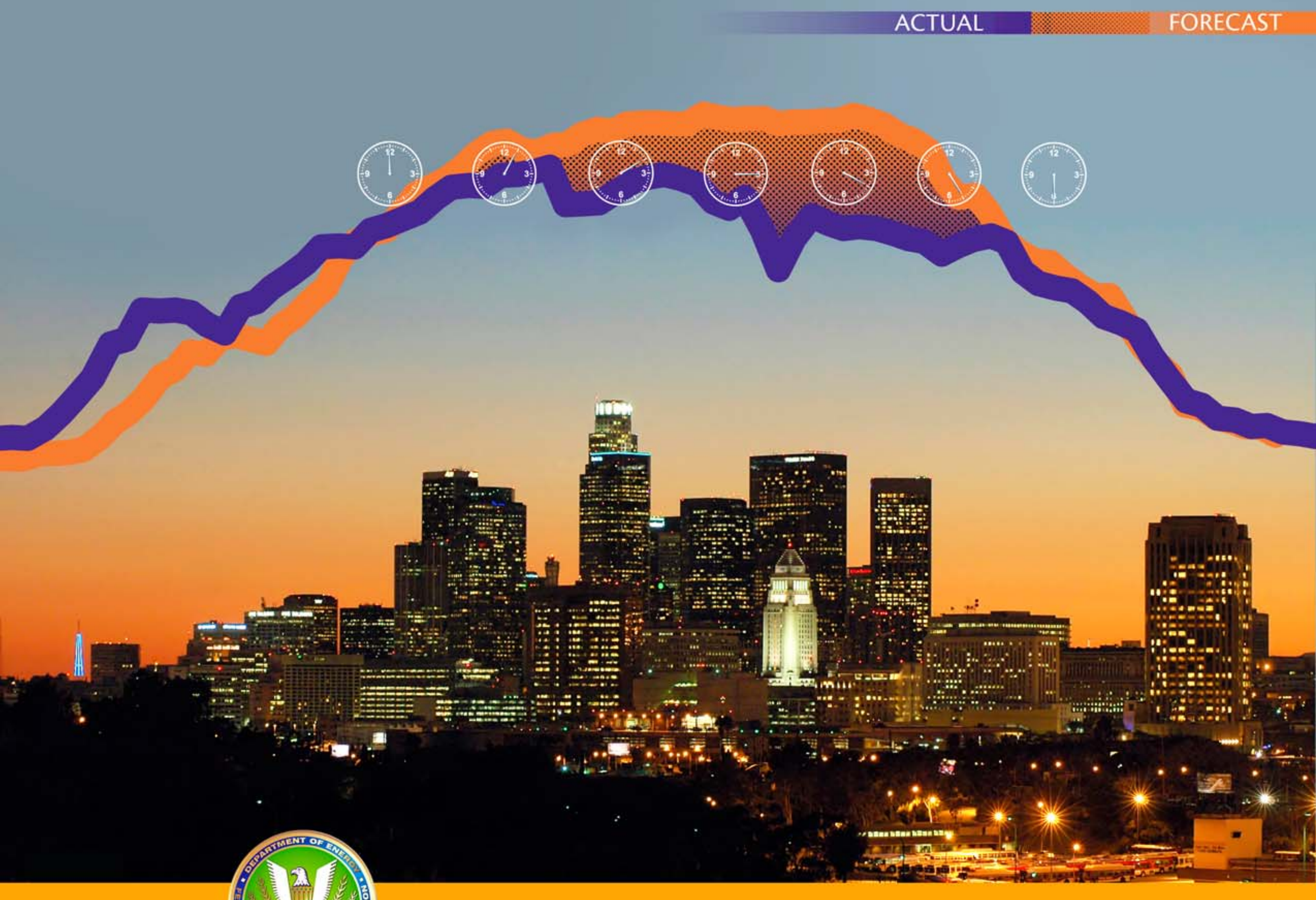
A National Assessment of
Demand Response Potential



STAFF REPORT

FEDERAL ENERGY REGULATORY COMMISSION

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PREPARED BY

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ACKNOWLEDGEMENTS

The analysis presented in this report was produced by a team of consultants from The Brattle Group (TBG), Freeman, Sullivan & Co. (FSC) and Global Energy Partners (GEP). Each firm led different parts of the project, typically with significant input from the other firms. TBG managed the project and was the lead contractor to the Federal Energy Regulatory Commission (FERC). TBG also had the lead in producing this report. FSC was the lead contractor on model development, and also developed the state and customer-segment level load shapes that were used as starting points for developing demand response impacts. FSC and TBG worked together to develop price impacts that reflect the extensive research that has been done in this area. GEP had the lead on data development with input from both TBG and FSC. Gary Fauth, an independent consultant specializing in advanced metering business case analysis, had the lead role in producing the advanced metering deployment scenario that underlies one of the potential estimates. Senior staff from all three firms worked jointly to develop scenario definitions and to provide defensible input assumptions for key drivers of demand response potential.

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EXECUTIVE SUMMARY

Energy Independence and Security Act of 2007

Section 529 (a) of the Energy Independence and Security Act of 2007[1] (EISA 2007) requires the Federal Energy Regulatory Commission (Commission or FERC) to conduct a National Assessment of Demand Response Potential[2] (Assessment) and report to Congress on the following:

- Estimation of nationwide demand response potential in 5 and 10 year horizons on a State-by-State basis, including a methodology for updates on an annual basis;
- Estimation of how much of the potential can be achieved within those time horizons, accompanied by specific policy recommendations, including options for funding and/or incentives for the development of demand response;
- Identification of barriers to demand response programs offering flexible, non-discriminatory, and fairly compensatory terms for the services and benefits made available; and
- Recommendations for overcoming any barriers.

EISA 2007 also requires that the Commission take advantage of preexisting research and ongoing work and insure that there is no duplication of effort. The submission of this report fulfills the requirements of Section 529 (a) of EISA 2007.

This Assessment marks the first nationwide study of demand response potential using a state-by-state approach. The effort to produce the Assessment is also unique in that the Commission is making available to the public the inputs, assumptions, calculations, and output in one transparent spreadsheet model so that states and others can update or modify the data and assumptions to estimate demand response potential based on their own policy priorities. This Assessment also takes advantage of preexisting research and ongoing work to insure that there is no duplication of effort.

Estimate of Demand Response Potential

In order to estimate the nationwide demand response potential in 5 and 10 year horizons, the Assessment develops four scenarios of such potential to reflect different levels of demand response programs. These scenarios are: Business-as-Usual, Expanded Business-as-Usual, Achievable Participation and Full Participation. The results under the four scenarios illustrate how the demand response potential varies according to certain variables, such as the number of customers participating in existing and future demand response programs, the availability of dynamic pricing[3] and advanced metering infrastructure

[1] Energy Independence and Security Act of 2007, Pub. L. No. 110-140, § 529, 121 Stat. 1492, 1664 (2007) (to be codified at National Energy Conservation Policy Act § 571, 42 U.S.C. §§ 8241, 8279) (EISA 2007). The full text of section 529 is attached as Appendix F.

[2] In the Commission staff's demand response reports, the Commission staff has consistently used the same definition of "demand response" as the U.S. Department of Energy (DOE) used in its February 2006 report to Congress:

> Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

U.S. Department of Energy, Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005, February 2006 (February 2006 DOE EPAct Report).

[3] In this Assessment, dynamic pricing refers to prices that are not known with certainty ahead of time. Examples are "real time pricing," in which prices in effect in each hour are not known ahead of time, and "critical peak pricing" in which prices on certain days are known ahead of time, but the days on which those prices will occur are not known until the day before or day of consumption. Static time-varying prices, such as traditional time-of-use rates, in which prices vary by rate period, day of the week and season but are known with certainty, are not part of this analysis.

(AMI)[4], the use of enabling technologies, and varying responses of different customer classes. Figure ES-1 illustrates the differences in peak load starting with no demand response programs and then comparing the four scenarios. The peak demand without any demand response is estimated to grow at an annual average growth rate of 1.7 percent, reaching 810 gigawatts (GW) in 2009 and approximately 950 GW by 2019.[5]

This peak demand can be reduced by varying levels of demand response under the four scenarios. Under the highest level of demand response, it is estimated that there would be a leveling of demand between 2009 and 2019, the last year of the analysis horizon. Thus, the 2019 peak load could be reduced by as much as 150 GW, compared to the Business-as-Usual scenario. To provide some perspective, a typical peaking power plant is about 75 megawatts[6], so this reduction would be equivalent to the output of about 2,000 such power plants.

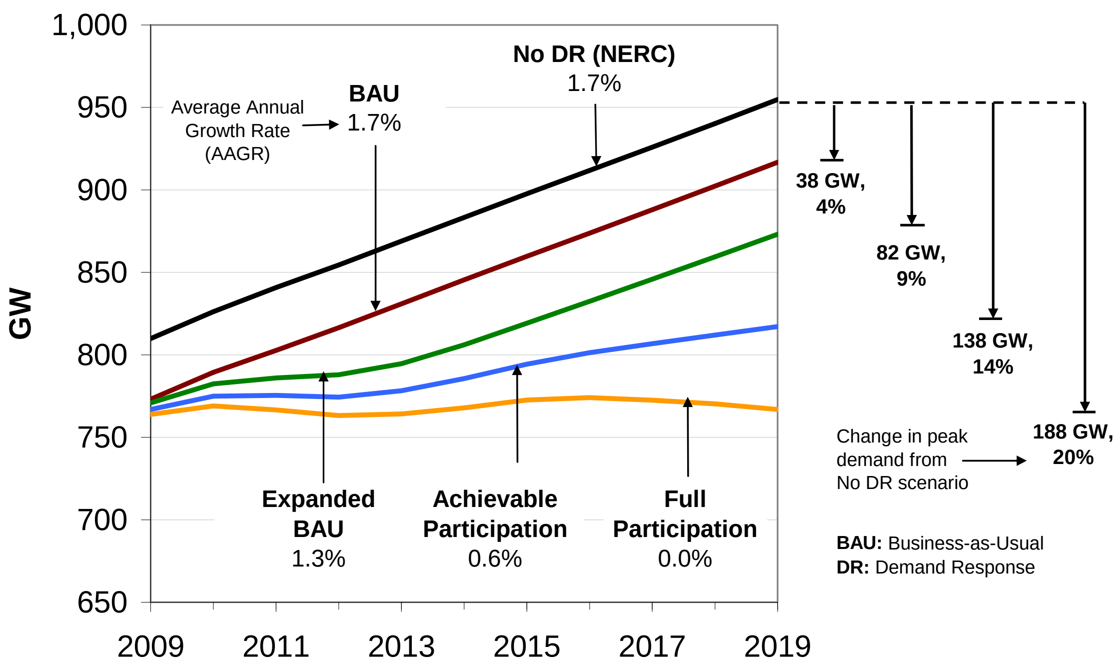

Figure ES-1: U.S. Peak Demand Forecast by Scenario

The amount of demand response potential that can be achieved increases as one moves from the Business-as-Usual scenario to the Full Participation scenario.

It is important to note that the results of the four scenarios are in fact estimates of **potential,** rather than **projections of what is likely to occur**. The numbers reported in this study should be interpreted as the amount of demand response that could potentially be achieved under a variety of assumptions about the types of programs pursued, market acceptance of the programs, and the overall cost-effectiveness of the

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4 A system including measurement devices and a communication network, public and/or private, that records customer consumption, and possibly other parameters, hourly or more frequently and that provides for daily or more frequent transmittal of measurements to a central collection point. AMI has the capacity to provide price information to customers that allows them to respond to dynamic or changing prices.

5 The "No DR (NERC)" baseline is derived from North American Electric Reliability Corporation data for total summer demand, which excludes the effects of demand response but includes the effects of energy efficiency. 2008 Long Term Reliability Assessment, p. 66 note 117; data at http://www.nerc.com/fileUploads/File/ESD/ds.xls

6 Energy Information Administration, Existing Electric Generating Units in the United States, 2007, available at http://www.eia.doe.gov/cneaf/electricity/page/capacity/capacity.html

programs. This report does not advocate what programs/measures should be adopted/implemented by regulators; it only sets forth estimates should certain things occur.

As such, the estimates of potential in this report should not be interpreted as targets, goals, or requirements for individual states or utilities. However, by quantifying potential opportunities that exist in each state, these estimates can serve as a reference for understanding the various pathways for pursuing increased levels of demand response.

As with any model-based analysis in economics, the estimates in this Assessment are subject to a number of uncertainties, most of them arising from limitations in the data that are used to estimate the model parameters. Demand response studies performed with accurate utility data have had error ranges of up to ten percent of the estimated response per participating customer. In this analysis, the use of largely publicly-available, secondary data sources makes it likely that the error range for any particular estimate in each of the scenarios studied is larger, perhaps as high as twenty percent.[7]

Business-as-Usual Scenario

The Business-as-Usual scenario, which we use as the base case, considers the amount of demand response that would take place if existing and currently planned demand response programs continued unchanged over the next ten years. Such programs include interruptible rates and curtailable loads for Medium and Large commercial and industrial customers, as well as direct load control of large electrical appliances and equipment, such as central air conditioning, of Residential and Small commercial and industrial consumers.

The reduction in peak demand under this scenario is 38 GW by 2019, representing a four percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Expanded Business-as-Usual Scenario

The Expanded Business-as-Usual scenario is the Business-as-Usual scenario with the following additions: 1) the current mix of demand response programs is expanded to all states, with higher levels of participation ("best practices" participation levels);[8] 2) partial deployment of advanced metering infrastructure; and 3) the availability of dynamic pricing to customers, with a small number of customers (5 percent) choosing dynamic pricing.

The reduction in peak demand under this scenario is 82 GW by 2019, representing a 9 percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Achievable Participation Scenario

The Achievable Participation scenario is an estimate of how much demand response would take place if 1) advanced metering infrastructure were universally deployed; 2) a dynamic pricing tariff were the default; and 3) other demand response programs, such as direct load control, were available to those who decide to opt out of dynamic pricing. This scenario assumes full-scale deployment of advanced metering

[7] For example, an estimated demand response potential of 19 percent could reflect actual demand response potential ranging from 15 to 23 percent. See Chapter II for a description of one source of error resulting from data limitations, and Appendix E for an analysis of uncertainties arising from the study assumptions.

[8] For purposes of this Assessment, "best practices" refers only to high rates of participation in demand response programs, not to a specific demand response goal nor the endorsement of a particular program design or implementation. The best practice participation rate is equal to the 75th percentile of ranked participation rates of existing programs of the same type and customer class. For example, the best practice participation rate for Large Commercial & Industrial customers on interruptible tariffs is 17% (as shown in Table 5). See Chapter V for a full description.

infrastructure by 2019. It also assumes that 60 to 75 percent of customers stay on dynamic pricing rates, and that many of the remaining choose other demand response programs. In addition, it assumes that, in states where enabling technologies (such as programmable communicating thermostats) are cost-effective and offered to customers who are on dynamic pricing rates, 60 percent of the customers will use these technologies.

The reduction in peak demand under this scenario is 138 GW by 2019, representing a 14 percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Full Participation Scenario

The Full Participation scenario is an estimate of how much cost-effective demand response would take place if advanced metering infrastructure were universally deployed and if dynamic pricing were made the default tariff and offered with proven enabling technologies. It assumes that all customers remain on the dynamic pricing tariff and use enabling technology where it is cost-effective.

The reduction in peak demand under this scenario is 188 GW by 2019, representing a 20 percent reduction in peak demand for 2019 compared to a scenario with no demand response programs.

Other Results of the Assessment

As shown in Figure ES-1, the size of the demand response potential increases from scenario to scenario, given the underlying assumptions.[9] Comparing the relative impacts of the four scenarios on a national basis, moving from the Business-as-Usual scenario to the Expanded Business-as-Usual scenario, the peak demand reduction in 2019 is more than twice as large. This difference is attributable to the incremental potential for aggressively pursuing traditional programs in states that have little or no existing participation. However, more demand response can be achieved beyond these traditional programs. By also pursuing dynamic pricing the potential impact could further be increased by 54 percent, the difference between the Achievable Participation scenario and the Expanded Business-as-Usual scenario. Removing the assumed limitations on market acceptance of demand response programs and technologies would result in an additional 33 percent increase in demand response potential (the difference between the Achievable Potential and Full Potential scenarios). A conclusion of this Assessment is that at the national level the largest gains in demand response impacts can be made

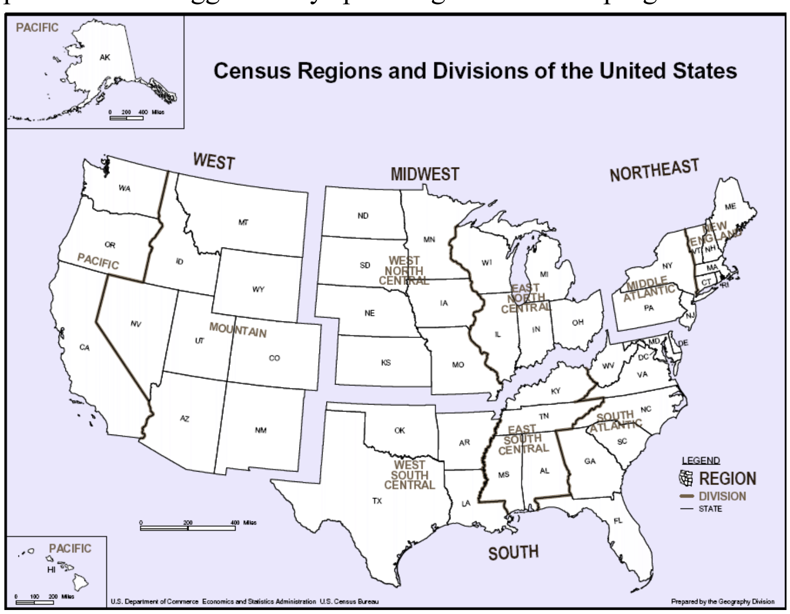

Figure ES- 2: Census Regions

9 There are other technologies that have the potential to reduce demand. These include emerging smart grid technologies, distributed energy resources, targeted energy efficiency programs, and technology-enabled demand response programs with the capability of providing ancillary services in wholesale markets (and increasing electric system flexibility to help accommodate variable resources such as wind generation.) However, these were not included in this Assessment because there is not yet sufficient experience with these resources to meaningfully estimate their potential.

through dynamic pricing programs when they are offered as the default tariff, particularly when they are offered with enabling technologies.

A mapping of states divided into the nine Census Divisions is provided in Figure ES-2. Regional differences in the four demand response potentials are portrayed by Census Division in Figure ES-3. To adjust for the variation in size among the divisions, the impacts are shown as a percentage of each Division's peak demand.

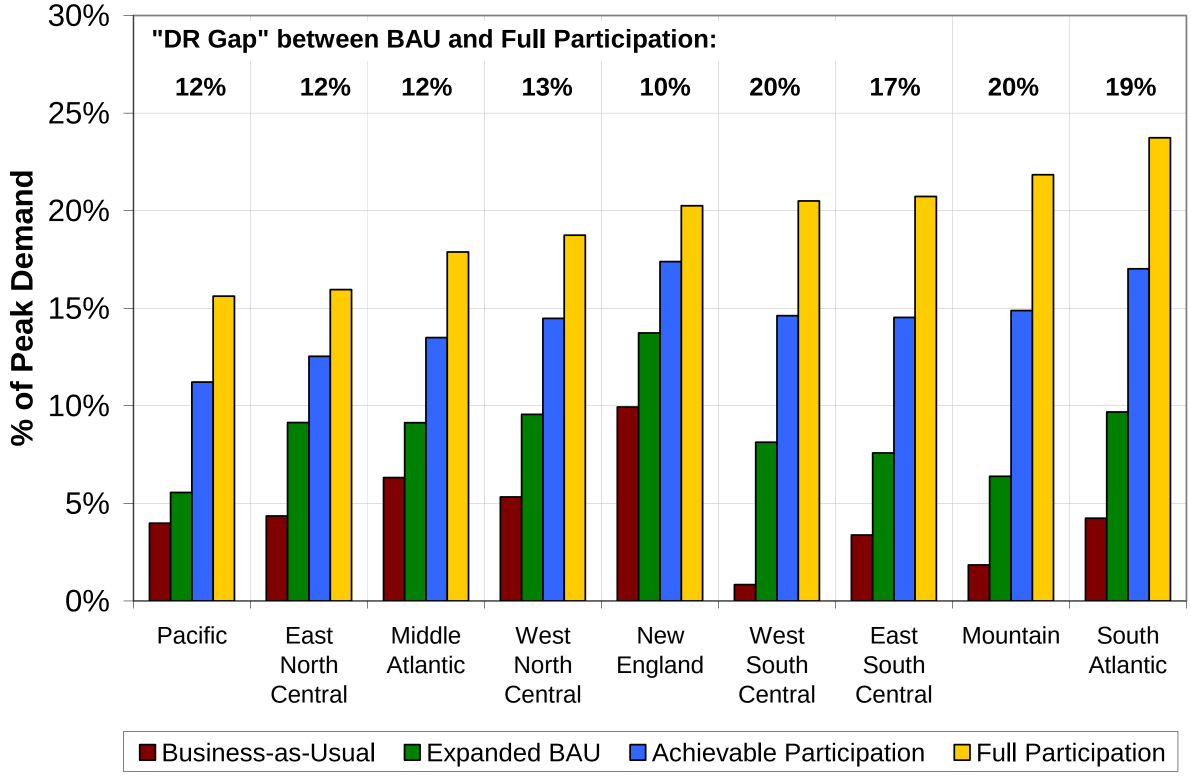

Figure ES-3: Demand Response Potential by Census Division (2019)

Regional differences in the estimated potential by scenario can be explained by factors such as the prevalence of central air conditioning, the mix of customer type, the cost-effectiveness of enabling technologies, and whether regions have both Independent System Operator/Regional Transmission Organization (ISO/RTO) and utility/load serving entity programs. For example, in the Business-as-Usual scenario, the largest impacts originate in regions with ISO/RTO programs that co-exist with utility/load serving entity programs. New England and the Middle Atlantic have the highest estimates, with New England having the ability to reduce nearly 10 percent of peak demand.

The prevalence of central air conditioning plays a key role in determining the magnitude of Achievable and Full Participation scenarios. Hotter regions with higher proportions of central air conditioning, such as the South Atlantic, Mountain, East South Central, and West South Central Divisions, could achieve greater demand response impacts per participating customer from direct load control and dynamic pricing programs. As a result, these regions tend to have larger overall potential under the Achievable and Full Participation scenarios, where dynamic pricing plays a more significant role, than in the Expanded Business-as-Usual scenario.

The cost-effectiveness of enabling technologies[10] also affects regional differences in demand response potential. Due to the low proportion of central air conditioning in the Pacific, New England, and Middle Atlantic Divisions, the benefits of the incremental peak reductions from enabling technologies, as determined in this study, do not outweigh the cost of the devices, so the effect of enabling technologies is excluded from the analysis. As a result, in some of these states and in some customer classes the demand reductions from dynamic pricing reflect only manual (rather than automated) customer response and so are lower than in states where customers would be equipped with enabling technologies. This also applies to the cost-effectiveness of direct load control programs.

The difference between the Business-as-Usual and Full Participation scenarios represents the difference between what the region is achieving today and what it could achieve if all cost-effective demand response options were deployed. Regions with the highest potential under the Full Participation scenario do not necessarily have the largest difference between Business-As-Usual and Full Participation. Generally, regions in the western and northeastern U.S. tend to be the closest to achieving the full potential for demand response, with the Pacific, Middle Atlantic, and New England regions all having gaps of 12 percent or less. Other regions, particularly in the southeastern U.S., have differences of as much as 20 percent of peak demand.

Comparing the results for these four scenarios provides a basis for policy recommendations. For example, the difference between the Business-As-Usual scenario and the Full Participation scenario reveals the “gap” between what is being achieved today through demand response and what could economically be realized in the future if appropriate polices were implemented. Similarly, the difference between the Expanded Business-as-Usual and the Achievable Participation scenarios reveals the additional amount of demand response that could be achieved with policies that rely on both dynamic pricing and other types of programs. The Assessment also provides valuable insight regarding regional and state differences in the potential for demand response reduction, allowing comparisons across the various program types – dynamic pricing with and without enabling technologies, direct load control, interruptible tariffs, and other types of demand response programs such as capacity bidding and demand bidding – to identify programs with the most participation today and those with the most room for growth.

Complete results for each of the fifty states and the District of Columbia are shown in Appendix A.

Barriers to Demand Response Programs and Recommendations for Overcoming the Barriers

A number of barriers need to be overcome in order to achieve the estimated potential of demand response in the United States by 2019. While the Assessment lists 25 barriers to demand response, the most significant are summarized here.

<u>Regulatory Barriers</u>. Some regulatory barriers stem from existing policies and practices that fail to facilitate the use of demand response as a resource. Regulatory barriers exist in both wholesale and retail markets.

- Lack of a direct connection between wholesale and retail prices.
- Measurement and verification challenges.
- Lack of real time information sharing.
- Ineffective demand response program design.

[10] The Assessment evaluates the cost-effectiveness of devices such as programmable communicating thermostats and excludes them where not cost-effective. See Chapter V for a complete description of the methodology.

- Disagreement on cost-effectiveness analysis of demand response.

Technological Barriers.

- Lack of advanced metering infrastructure.
- High cost of some enabling technologies.
- Lack of interoperability and open standards.

Other Barriers.

- Lack of customer awareness and education.
- Concern over environmental impacts.

As discussed above, three scenarios estimating potential reductions from the Business-as-Usual scenario have been developed. These scenarios estimate at 5 and 10 year horizons how much potential can be achieved by assuming certain actions on the part of customers, utilities and regulators. Each utility, together with state policy makers, must decide whether and how best to move forward with adoption of demand response, given their particular resources and needs; however, steps can be taken to help inform individual utility decisions and state policies, as well as national decisions.[11]

The increase in demand response under the Expanded Business-as-Usual scenario rests on the assumption that current "best practice"[12] demand response programs, such as direct load control and interruptible tariff programs, are expanded to all states and that there is some participation in dynamic pricing at the retail level. To encourage this expansion to all states and some adoption of dynamic pricing, FERC staff recommends that:

- Coordinated national and local education efforts should be undertaken to foster customer awareness and understanding of demand response, AMI and dynamic pricing.
- Information on program design, implementation and evaluation of these "best practices" programs should be widely shared with other utilities and state and local regulators.
- Demand response programs at the wholesale and retail level should be coordinated so that wholesale and retail market prices are consistent, possibly through the NARUC-FERC Collaborative Dialogue on Demand Response process.
- Both energy efficiency and demand response principles should be included and coordinated in education programs and action plans, to broaden consumers' and decision makers' understanding, improve results and use program resources effectively.
- Expanded demand response programs should be implemented nationwide, where cost-effective.
- Technical business practice standards for evaluating, measuring and verifying energy savings and peak demand reduction in the wholesale and retail electric markets should be developed.

[11] On a separate track FERC issued the Wholesale Competition Final Rule, which recognized the importance of demand response in ensuring just and reasonable wholesale prices and reliable grid operations. As part of the Final Rule, FERC required all RTOs and ISOs to study whether further reforms were necessary to eliminate barriers to comparable treatment of demand response in organized markets, among other things. Most RTOs and ISOs submitted filings that identified the particular barriers and possible reforms for their specific markets. Wholesale Competition in Regions with Organized Electric Markets, Order No. 719, 73 Fed. Reg. 64, 100 (Oct. 28, 2008), FERC Stats. & Regs. ¶ 61,071 (2008).

[12] See definition of "best practices" at note 7.

- Open standards for communications and data exchange between meters, demand response technologies and appliances should be encouraged and supported, particularly the efforts of the National Institute of Standards and Technology to develop interoperability standards for smart grid devices and systems.
- Cost-effectiveness tools should be developed or revised to account for many of the new environmental challenges facing states and the nation, and to reflect the existence of wholesale energy and capacity markets in many regions.
- Regulators and legislators should clearly articulate the expected role of demand response to allow utilities and others to 1) plan for and include demand response in operational and long-term planning, and 2) recover associated costs.

The Achievable Participation and Full Participation scenarios estimate that the largest demand response would take place if advanced metering infrastructure were universally deployed and consumers respond to dynamic pricing. The Achievable Participation scenario is realized if all customers have dynamic pricing tariffs as their default tariff and 60 to 75 percent of customers adopt this default tariff, while the Full Participation scenario is based on all consumers responding to dynamic prices. For this to occur, in addition to the recommendations above,

- Dynamic pricing tariffs should be implemented nationwide.
- Information on AMI technology and its costs and operational, market and consumer benefits should be widely shared with utilities and state and local regulators.
- Grants, tax credits and other funding for research into the cost and interoperability issues surrounding advanced metering infrastructure and enabling technologies should be considered, as appropriate.
- Expanded and comprehensive efforts to educate consumers about the advantages of AMI and dynamic pricing should be undertaken.

The Full Participation scenario is dependent upon removal of limitations to market acceptance through implementation of these recommendations, and all customers must be able to respond under dynamic pricing.

FERC is required by Section 529 of EISA 2007, within one year of completing this Assessment, to complete a National Action Plan on Demand Response. The Action Plan will be guided in part by the results of this Assessment.

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