Potential Availability of and Supply Curves for Low-Cost, Dispatch-Constrained Electricity

Mark F. Ruth, Paige N. Jadun, and Wesley Cole

National Renewable Energy Laboratory

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Foreword

This report summarizes analysis work performed in 2018–2019 to support an analysis of *The Technical and Economic Potential of the H2@Scale Concept within the United States.*[1] In that report, this work is cited as forthcoming; however, this work was not released before that report was published due to requirements for additional validation of analysis results of grid performance and subsequent electricity price calculations resulting from methodological differences between the National Renewable Energy Laboratory's capacity expansion model (the Regional Energy Deployment System [ReEDS – 2017 Version] and the production cost model (PLEXOS 7.4). We partially address those concerns in Appendix E.

We are releasing this analysis now (in 2023) to provide transparency in the former work that cited this paper as "forthcoming," and so that other analysts can build upon the data and cite the work.

However, the analysis was performed in 2019, corresponding to cost assumptions and model version that may be out of date. Changes in technology, costs, markets, and policy are likely to impact the quantity and cost of low-cost, dispatch-constrained electricity (LDE) due to developments in both the generation fleet and in potential markets.

In addition, and analyses of curtailed energy performed since 2019 are not cited in this report.

[1] Ruth, Mark, Paige Jadun, Nicholas Gilroy, Elizabeth Connelly, Richard Boardman, A.J. Simon, Amgad Elgowainy, and Jarett Zuboy. 2020. *The Technical and Economic Potential of the H2@Scale Concept within the United States*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77610. https://www.nrel.gov/docs/fy21osti/77610.pdf.

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List of Acronyms

AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
CAISO	California Independent System Operator
CREZ	Competitive Renewable Energy Zone
CSP	Concentrating Solar Power
dGen	Distributed Generation Model
DOE	U.S. Department of Energy
ERCOT	Electric Reliability Council of Texas
LCOE	Levelized Cost of Energy
LDE	Low-cost, Dispatch-constrained Electricity
LMP	Locational Marginal Price
NG-CC	Natural Gas Combined Cycle
NG-CT	Natural Gas Combustion Turbine
NREL	National Renewable Energy Laboratory
PV	Photovoltaic
ReEDS	Regional Energy Deployment System
RTO	Regional Transmission Organization
VRE	Variable Renewable Energy

Executive Summary

Technology development, economic factors, and policy are driving changes in the U.S. electricity system. Among other changes, variable renewable energy (VRE)—primarily wind and solar photovoltaics—is achieving a growing share of total generation. High VRE penetrations may result in an increased level of curtailment and thus suppress the value of additional VRE. This VRE, that either would not be built due to price suppression or would be curtailed, can be considered a resource that we define as low-cost, dispatch-constrained electricity (LDE). LDE could be used for various applications that value low-cost electricity and can operate at reduced capacity factors. Examples include electrolytic hydrogen production and carbon capture. This report provides initial estimates of the quantity and availability of the potential LDE resource in the United States under scenarios with high VRE penetrations. It also provides supply curves that can be used in subsequent analysis of the opportunity to use the LDE.

We modeled several scenarios using capacity expansion and production cost models for LDE prices ranging from $0/MWh to $30/MWh. These LDE prices, coupled with low renewable energy cost assumptions, resulted in VRE penetrations ranging from 48–66% in 2050. The resulting LDE supplies range from 100–300 TWh/yr at a price of $0/MWh to 3,500–4,200 TWh/yr at $30/MWh. Increasing LDE prices increases wind and photovoltaics deployment; however, other generation technology capacities do not decrease equivalently in our models. Thus, additional generation is available but the capacity of traditional dispatchable generation is only reduced slightly. The available LDE is concentrated in the Central and Southwest U.S. regions because of their high wind and solar resources. Availability of LDE varies on both seasonal and diurnal scales, resulting in capacity factors of 7–40% if all available LDE is utilized, but can be much higher if some of that LDE is curtailed. Thus, the LDE resource is large but will depend upon applications that can operate economically at low capacity factors, transmission of the LDE to locations where it can be utilized, and market structures that allow it to be purchased at low prices.

Data are available at https://data.nrel.gov/submissions/211. The dataset includes the quantity of estimated LDE resource for each hour of the year in 2050, aggregated to both the national level and the ReEDS balancing area level. The dataset also includes the report figure data.

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1 Background and Objective

The U.S. electricity system is evolving due to economic and policy changes. Currently, the system operates primarily with large central generation supplying distributed loads. The central generators are often classified into two categories: (1) baseload generators that operate at a constant output during most hours of the year and (2) intermediate and peaking generators that have higher operating costs, but are ramped or turned on and off to match load (DOE 2017). A third category, variable renewable electricity (VRE), such as wind and solar photovoltaic (PV), has very low operating costs. VRE generation is set by the availability of the wind or solar resource at any given time, so generation output is not constant, nor does it typically adjust to follow changes in load. The market share of VRE is increasing as costs decline. Wind and solar generation grew from 0.2% of total generation in 2000 to over 8% in 2018 (EIA 2019), and this trend is expected to continue (W. Cole et al. 2017; EIA 2017). The difference between the total load and VRE generation is the “net load,” and the daily and seasonal variability of net load increases at higher penetrations of VRE, creating potential challenges for grid operations (Mills and Wiser 2013).

Growth in VRE deployment often leads to an increased level of curtailment—where curtailment is defined as a reduction in the output of a generator from its potential without reducing resource utilization (Bird, Cochran, and Wang 2014). When wind and sunlight are available and generators have been built to convert that energy to electricity for a negligible marginal cost, those units may be curtailed when the system’s generation exceeds load. Thermal generators, such as coal and natural gas, can usually reduce generation to follow load and avoid incurring excess operating costs; however, they are limited by their minimum operating constraints as they turn down (Paul Denholm, Brinkman, and Mai 2018; Bistline 2019). Currently, the primary driver for curtailment is insufficient transmission capacity to move electrical energy from locations where generation exceeds load to locations where thermal generation can be reduced. However, curtailment can also be caused by voltage or interconnection issues (Bird, Cochran, and Wang 2014). In an increasing number of locations, curtailment occurs because total generation exceeds load and thermal generation cannot be further reduced or turned off because that generation capacity will be needed in the potential absence of VRE resource (i.e., clouds cover the sun or the wind stops blowing), or because of minimum operating constraints or other technical constraints prohibiting the plant from turning down further (Tuttle and Powell 2019; Paul Denholm, Brinkman, and Mai 2018; Bistline 2019).

As of 2019, curtailment within the United States has been low. The national wind curtailment was less than 3% in 2017 (DOE, 2018), and the California Independent System Operator (CASIO) reported solar curtailment rates of less than 2% in 2018 (CAISO 2019). In 2009, before the transmission capacity expansion under the Electric Reliability Council of Texas’ (ERCOT’s) Competitive Renewable Energy Zone (CREZ) initiative, wind curtailment in the ERCOT territory reached 17% (Bird, Cochran, and Wang 2014). However, Potomac Economics (2017) found ERCOT’s wind curtailment rates to be 0.5%, 1%, and 2% in 2014, 2015, and 2016, respectively. Strategies such as expanding transmission and improving operating practices (e.g., automation, better forecasting) have reduced the need for curtailment, thus counteracting the challenges of increased VRE penetration. For that reason, some analyses have shown a decrease in curtailment over recent years (Bird, Cochran, and Wang 2014), whereas some forward-looking studies have projected increases (Mills and Wiser 2013; Denholm et al. 2016).

Although low today, curtailment may increase with VRE penetration. For example, the California 2030 Low Carbon Grid Study showed that curtailment in California for low carbon scenarios could range from less than 1% in a scenario with high grid flexibility to 10% for a scenario with limited grid flexibility and high solar penetration (30%) (Brinkman et al. 2016). The Renewable Electricity Futures study estimates that 8%-10% of wind, solar, and hydropower generation would need to be curtailed in a scenario with 80% of the total generation sourced from (Hand et al. 2012). The exact levels of potential curtailment due to overgeneration are unclear, but in general, curtailment is expected to increase with VRE penetration (Mills and Wiser 2013; Denholm, Margolis, and Milford 2008; Denholm and Mai 2017; Golden and Paulos 2015; Solomon, Kammen, and Callaway 2014).

Future curtailment could be reduced through additional flexibility measures such as energy storage and demand management. Storage, including both battery and thermal, of electrical energy is a common proposal (Bitaraf and Rahman 2017; Denholm and Mai 2017; Solomon, Kammen, and Callaway 2014; Ali et al. 2017; Chen and Zhao 2017). Others propose use of controllable loads through demand response, such as charging of plug-in electric vehicles (Liu et al. 2017; Ali et al. 2017).

However, the coincident nature of VRE generation could limit VRE penetration before high levels of curtailment occur due to declining value of the energy generated. As penetrations of renewables increase, the value of the generated electricity can be expected to fall because prices are driven by marginal operating costs, which are minimal for VRE generators (Hand et al. 2012). Mills and Wiser (2013) found that energy prices for PV generation are suppressed by 75% at 30% PV penetration, and energy prices for wind generation are suppressed by 40% at 40% wind penetration. Due to that price suppression, investments in new VRE generation capacity may have an insufficient value proposition to motivate additional investment (Wiser et al. 2017).

Additional loads could utilize the excess VRE, which in turn could reduce curtailment and help stabilize VRE power prices through providing a demand for the low-cost electricity available during periods of oversupply on the grid. We refer to this electricity as low-cost, dispatched-constrained electricity (LDE). This LDE is essentially electricity that would otherwise be curtailed if a load was not available to absorb it. Many major initiatives and studies envision abundant, low-cost VRE and anticipate using excess VRE (i.e., LDE) for productive purposes, such as hydrogen production from electrolyzers. For example, the U.S. Department of Energy's (DOE's) H2@Scale initiative seeks to reduce hydrogen production costs from low-temperature electrolysis by utilizing excess VRE as the feedstock (Stevens et al. 2017; DOE 2019), and some in the United Kingdom recently called for using excess VRE as a means to produce hydrogen (Institution of Mechanical Engineers 2018). Many researchers, especially in Germany and island communities, are investigating opportunities to utilize LDE to produce hydrogen for injection into natural gas systems at low concentrations (Melaina, Antonia, and Penev 2013), or for further conversion to methane, which can then be injected into the natural gas system at higher concentrations (Troncoso and Newborough 2011; Simonis and Newborough 2017; Zhang and Wan 2014; Kaldellis, Kavadias, and Zafirakis 2015; Peron and Van Dam 2015). Hydrogen can also be an energy source or feedstock for a number of other industries (Stevens et al. 2017).

Additionally, some researchers have proposed using LDE to power carbon-capture devices (Li et al. 2015).

These potential supplemental loads may improve the economics for VRE and increase market sizes if the consumers of the additional loads are willing to pay a small price for the excess energy. For example, deploying additional generating units solely to provide electricity to the grid may not be profitable due to the price suppression mentioned above, but demand for LDE can set a price floor for that generation, thus improving the prospective generator's economics. In other situations, especially those with very low generator costs (Cole et al. 2018), building new generators just to produce LDE may make economic sense; however, depending on the required price of electricity for the given end use and the levelized cost of generating the electricity, it could be optimal to build new plants primarily to provide LDE for supplemental demand, but with the ability to sell electricity to the grid when prices are high.

In the academic literature, references to using excess VRE are abundant, as shown above. However, there has been limited work to understand the availability of excess renewable energy in quantity, timing, and cost. Because production costs generally decline with increased utilization rates, abundant excess VRE over a short duration might be less valuable than lower levels of excess VRE that are spread across a greater number of hours.

This report provides initial estimates of future LDE resources in the United States at high VRE penetrations. This report also quantifies the potential size, availability, and cost of that resource for use in subsequent analyses. We also endogenously calculate LDE based on technology and resource prices and include the feedback from generator investment decisions by using a capacity expansion model. To do so, we assign multiple prices to LDE—representing the willingness of markets to pay for that electricity—to estimate the projected buildout of electricity generation at each LDE price. The resulting generator fleet is input into a production cost model to examine the availability of LDE at an hourly resolution, and to develop national LDE supply curves. The supplemental value stream created by assigning a price to LDE could increase the penetration of VRE generation. The analysis is based on the supposition that without purchasers of LDE, electricity that exceeds load would be curtailed at no value; thus, the generation fleet and mix could change when the LDE has a value. This work only considers LDE supply within the electricity supply sector. It does not consider the impacts of varying electricity prices on loads or rebound effects for resources such as natural gas—both of which could impact LDE availability and prices. This work also does not consider competition between potential LDE users. Results from this work are the quantity of LDE that would be available given different prices of power and how the additional value stream affects the system buildout.

The remainder of this report is organized as follows: Section 2 summarizes the methodology used for the analysis; Section 3 reports the results and discusses them; Section 4 lists the conclusions from this analysis; and Section 5 identifies potential future analyses.

2 Methodology

In this work, we use a capacity expansion model to develop plausible electricity generation and transmission buildout with LDE through 2050 and then a production-cost model to evaluate the 2050 operations. The capacity expansion model that we use is the Regional Energy Deployment

System (ReEDS) model (Eurek et al. 2016) (2017 version). With it, we simulate the buildout of the U.S. power sector through 2050 at increasing prices of LDE. We then use the resulting generator capacity mix in a production-cost model (PLEXOS 7.4) (Energy Exemplar 2019), where we simulate the operation of the projected electricity system. PLEXOS has been used in previous analyses to validate and extend ReEDS results in other studies (Cole et al. 2018; Cole et al. 2019; Frew et al. 2019). We use the results from the production-cost model to estimate the regional and temporal availability of LDE for end-use services.

2.1 Capacity Expansion Model (ReEDS)

The ReEDS capacity expansion model, developed by the National Renewable Energy Laboratory (NREL), simulates the buildout and operation of the contiguous U.S. electricity system (Eurek et al. 2016). ReEDS minimizes the total system cost of the electricity system to determine the regional mix of technologies that satisfy physical and policy requirements. The model accounts for the type and location of fossil, nuclear, renewable, and storage resource development; the transmission infrastructure expansion requirements of those installations; and the generator dispatch and fuel needed to satisfy regional electricity consumption requirements and maintain grid system adequacy. ReEDS also accounts for technology, resource, and policy considerations, such as state renewable portfolio standards.

The primary outputs from ReEDS include the amount, type, year, and location of generator capacity; annual generation from each technology; storage capacity expansion; and transmission capacity expansion needed to satisfy regional electricity consumption requirements and maintain grid system adequacy. The generation and storage technologies modeled in ReEDS include various types of coal-fired power plants, natural-gas-fired power plants (combined cycle and open cycle), oil and gas steam, nuclear, wind (land-based and offshore), biopower, geothermal, hydropower, utility PV, concentrating solar power with and without thermal energy storage, pumped-hydropower storage, compressed-air energy storage, and utility-scale batteries. Distributed generation is represented in ReEDS via exogenous inputs from the NREL Distributed Generation (dGen) model (Sigrin et al. 2016).

ReEDS represents the electric sector with high spatial resolution to enable comparative electricity sector cost evaluation based on regional pricing and the relative value of geographically and temporally constrained renewable power sources. The model divides the contiguous United States into 134 “balancing area” regions, wherein electricity supply and consumption are balanced, and planning reserves are enforced. ReEDS also characterizes the quality, variability, uncertainty, and geographic resource constraints of renewable resources across these 134 regions; some technologies are further characterized into more resolved subregions (see Figure 1). Long-distance transmission is represented as single-path connections between most adjacent or near-adjacent modeling balancing area regions, and ReEDS models both existing transmission lines and new transmission capacity on these inter-region lines. ReEDS also models the intra-region “spur line” transmission costs required to connect renewable capacity to the transmission grid or load centers.

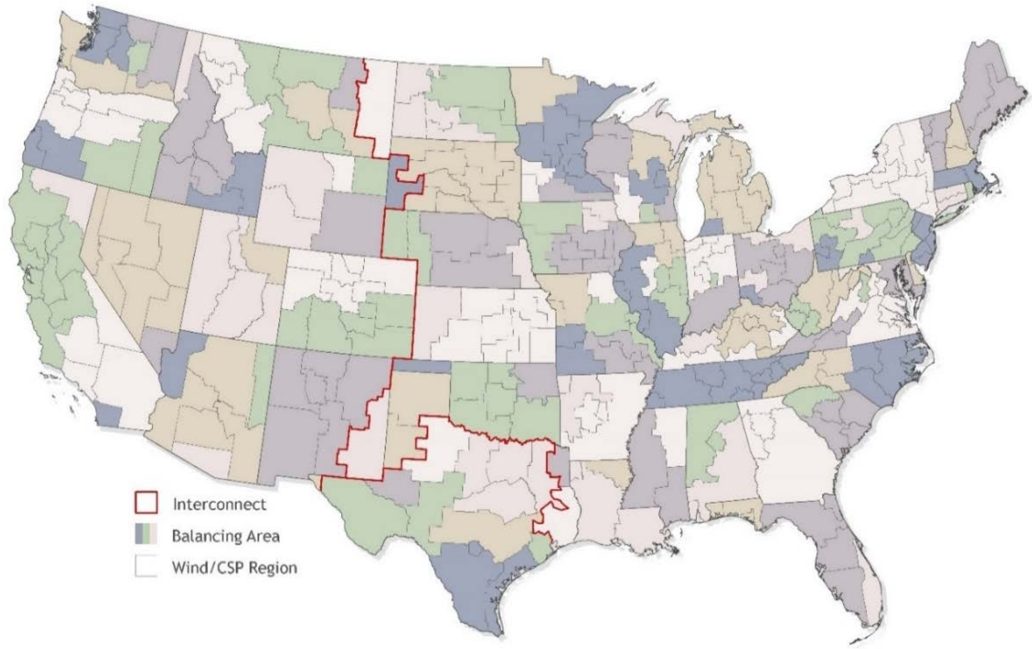

Figure 1. Map of the ReEDS balancing areas including wind and concentrating solar power (CSP) resource subregions

ReEDS is temporally resolved into 17 “timeslices” that each reflect a set of hours in each day within a season. For each 2-year solution interval from 2010 to 2050, ReEDS dispatches all generation in each of these 17 timeslices to capture seasonal and diurnal electricity load and renewable generation profiles. In between each solve year interval, ReEDS uses an hourly calculation method (Frew et al. 2017) that considers the hourly profiles of wind, solar, and load in each region to estimate the capacity value of wind and solar (i.e., the contribution of wind and solar to meeting peak demand). Additionally, between solve years, ReEDS estimates the curtailment rate of existing wind and solar units, as well as the marginal curtailment rate of new wind and solar units by considering coincidence in wind and solar generation relative to load, the minimum turndown of conventional generators, availability of storage, availability of transmission, and the self-coincidence of wind and solar generation (Eurek et al. 2016).

2.2 Production-Cost Model (PLEXOS)

PLEXOS is a commercial production-cost model capable of optimizing the least-cost dispatch of individual generating units and transmission nodes at an hourly or subhourly time resolution. The increased fidelity, including detailed operating constraints such as ramp rates and minimum runtime, allows for a more realistic simulation of power system operations than is possible in ReEDS. For this analysis, we use the ReEDS-PLEXOS linkage developed at NREL (Cohen et al. 2019) to disaggregate ReEDS capacity expansion solutions to a more detailed resolution necessary for PLEXOS. We simulate the hourly dispatch of our set of scenarios for the year 2050 to estimate the total availability and hourly profiles of LDE.

2.3 Effective Capacity Factor Calculations

The estimated level of LDE in PLEXOS varies hourly over the year for each region. We represent this temporal variability by calculating an effective capacity factor for a generic system that would be utilizing LDE. We define the effective capacity factor as the ratio of LDE that is utilized over a given time period to the technology's maximum load consumption over the same time period. For example, if a device can consume 1 MW over 10 hours (10 MWh potential), but only utilizes 3 MWh of LDE, the capacity factor would be 3/10 = 30%. The effective capacity factor represents how frequently this level of LDE will be available throughout the year and indicates the maximum capacity factor or utilization factor of a device or system that relies on LDE exclusively.

Each of the 134 regions in ReEDS will have a different amount of LDE (due to regional load and resource profiles and transmission constraints); therefore, we calculate the effective capacity factor of LDE for each ReEDS region. We also estimate the effective capacity factor for each region at varying system capacities, since a smaller system may achieve higher capacity factors, but with less LDE utilization potential. To represent a range of capacities and effective capacity factors, we calculate multiple effective capacity factors corresponding to the LDE available in each hour of the year, where the capacity factor for a given hour is based on a load that has a capacity equal to the quantity of electricity available in that hour (i.e., the maximum load is that hour's available LDE). The equation used to calculate the annual effective capacity factor in a given region, for example, is shown in Equation 1, where LDE_h is the LDE available in each hour h and LDE_{max} is the maximum load that can be utilized. Note that PLEXOS models 8,736 hours of the year, instead of 8,760.

Equation 1

$$Effective\ Capacity\ Factor_h = \frac{\sum_{h=1}^{8736} min(LDE_h, LDE_{max})}{LDE_{max} \times 8{,}736}$$

The calculated effective capacity factor also corresponds to a quantity of LDE that can be utilized. For example, the effective capacity factor for a system built to accommodate the highest hour of LDE in the year for a region corresponds to 100% utilization of the available LDE (i.e., if LDE_h is equal to LDE_{max}, 100% of the LDE will be utilized, but if LDE_h is less than LDE_{max}, then a smaller percentage will be utilized). Systems built with lower capacities may have higher effective capacity factors, but less of the total LDE would be utilized. Effective capacity factor results are presented in Section 3.2.

2.4 Scenario Description

We considered two scenarios in this study: Low Renewable Energy (RE) Cost and High Curtailment (Table 1). As described in Section 1, LDE resource will likely be more abundant at higher VRE penetrations; thus, both scenarios have high penetrations of VRE technologies. The Low RE Cost scenario is consistent with the Low RE Cost scenario from the 2017 Standard Scenarios Report (W. Cole et al. 2017), which uses the low-cost projections for renewable energy technologies (land-based and offshore wind, utility and distributed PV, hydropower, and geothermal) from the 2017 Annual Technology Baseline (ATB) (NREL 2017). These low-cost projections correspond to the low end of observed literature projections for these technologies. Natural gas prices are based on the Annual Energy Outlook (AEO) 2017 Reference scenario (EIA 2017). The High Curtailment scenario uses the same renewable energy low-cost projections, but also includes a high natural gas price trajectory (based on the AEO 2017 Low Oil & Gas Resource scenario (EIA 2017)]), shortens coal plant lifetimes by 10 years, and extends nuclear lifetimes such that all plants are granted a second relicense (unless they have already announced a retirement date). For both scenarios, non-renewable energy and storage technologies use the mid-case cost and performance projections from the 2017 ATB, and demand growth, coal prices, and uranium prices are from the AEO 2017 Reference scenario. All other assumptions are consistent with those presented in the 2017 Standard Scenarios (W. Cole et al. 2017), including expiration of the production tax credits for wind generation by 2023, and reduction of the investment tax credits for utility and commercial PV generation to 10% by 2025.

Table 1. Input Assumptions for Low RE Cost and High Curtailment Scenarios

Assumption	Low Renewable Energy Cost	High Curtailment
Renewable Energy Costs	Low-cost projections from 2017 Annual Technology Baseline	
Non-Renewable Energy Costs	Mid-cost projections from 2017 Annual Technology Baseline	
Storage Costs	Mid-cost projections from 2017 Annual Technology Baseline	
Natural Gas Prices	Reference scenario from 2017 Annual Energy Outlook[2]	Higher prices from Low Oil & Gas Resource scenario from 2017 Annual Energy Outlook[2]
Coal Retirements	Economic retirement	Lifetimes shortened by 10 years
Nuclear Lifetime	Mix of 60- and 80-year lifetime	80-year lifetime

All other input assumptions not listed are consistent with the Reference case in the 2017 Standard Scenarios (W. Cole et al. 2017).

2.5 Modeling Implementation

Both of these scenario settings are run at LDE values of $0, $5, $10, $15, $20, $25, and $30/MWh for a total of 14 scenarios. The LDE value is included as an additional term in the objective function of the ReEDS capacity expansion model that credits any surplus electricity at the LDE value. Thus, the model can choose to overgenerate (i.e., generate more electricity than the load requires), and receive compensation at the LDE value for that electricity, but the electricity would not be available to the system to meet normal system load. Since ReEDS solves for the lowest system cost under the constraint that generation meet load in all balancing areas and timeslices, the model allows all forms of generation to produce LDE. However, it is unlikely that natural gas generators would be operated in that way because the LDE values are lower than their fuel costs. Table 2 shows the range of the estimated levelized cost of energy (LCOE) projected for 2050 in the 2017 ATB, which varies by ATB scenario and by regional resource availability and cost. Only at prices above $25/MWh does the value of LDE begin to exceed the LCOE of some wind and PV generators.

The LDE prices reported in this analysis are wholesale electricity prices that would be paid to the electricity generator for that LDE (i.e., price of selling into the wholesale market). Purchasing access at wholesale prices may require changes to the current market structure. Electrical energy purchased in structured markets often costs about $20/MWh above the selling price to cover costs for capacity and ancillary services as well as the cost to operate the market (Monitoring Analytics, LLC 2017); therefore, the actual achievable purchase price may be higher than the

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[2] The Reference Scenario's prices for natural gas used for electricity generation range from $4.54/MMBtu in 2020 to $6.13/MMBtu in 2050. The Low Oil & Gas Resource Scenario's prices for natural gas used for electricity generation range from $5.15/MMBtu in 2020 to $10.24/MMBtu in 2050. Both are in 2016$

LDE prices shown here. The incremental price could partially be counteracted if the purchaser could provide capacity or ancillary services via a demand response or similar program.

Table 2. Range of the Estimated 2050 Levelized Cost of Energy in the 2017 Annual Technology Baseline for Various Generation Technologies

Generation Technology	Levelized Cost of Energy Range in 2050 ($/MWh)[a]
Coal	58–109
Natural Gas Combustion Turbine	89–182
Natural Gas Combined Cycle	51–57
Nuclear	78
Land-Based Wind	25–116
Utility-Scale Photovoltaic	26–53
Commercial Photovoltaic	49–88

[a]The range of costs reflects various technology advancement scenarios in the Annual Technology Baseline and regional resource variations.

The methodology implemented in this analysis has a number of limitations. First, this work assumes a perfect flexibility market for LDE and its end-use applications, and we do not consider the constraints surrounding transporting and storing LDE or the potential end-use products that utilize it (e.g., we assume supply of LDE is equal to demand across regions and time). Second, this analysis does not capture the price-demand dynamics that may occur with high levels of electricity entering the market; prices may fall as the market demand gets saturated or demand may be flexible and thus reduce price swings. Instead, we assume the demand will absorb the LDE supply at all prices and quantities. We also assume that periods of LDE do not correspond to periods of highest system stress. In other words, we assume that generators would not be curtailed during high-demand periods, such as peak load or peak net load, and therefore generators providing LDE are not restricted from providing electricity during these periods. Finally, we do not consider impacts on adjacent sectors that would impact the electric sector (e.g., a rebound effect on natural gas prices) or competition between potential LDE users. Finally, this work was performed using models and data available in 2019. Those models and data sets have subsequently evolved, and thus the results reported here may not still be valid.

3 Results and Discussion

This section reports the grid buildout and operation results from two sets of scenarios: Low RE Cost and High Curtailment. Section 3.1 includes the capacity and generation results from the capacity expansion model (ReEDS), and Section 3.2 details the corresponding LDE availability estimated in the production-cost model (PLEXOS) for each capacity expansion scenario.

3.1 Power Sector Evolution

To set baseline estimates of the quantity of potential excess electricity, ReEDS was run for the Low RE Cost scenario and the High Curtailment scenario with an LDE price of $0/MWh to calculate the least-cost system to meet the load through 2050. Figure 2 shows the resulting capacity and generation mixes of both scenarios. In the Low RE Cost scenario, the combined wind and PV generation share increases from 7% of total generation in 2016 to 48% in 2050, resulting in a grid with a greater need for flexibility than today's system. Coal generation share falls from 29% to 11% and nuclear generation share drops from 20% to 8% from 2016 to 2050 as older units are retired and replacements are less economically competitive than other generators. Natural gas generation at 1,100 TWh in 2050 is 23% less than generation in 2016 (1,400 TWh), and its share also decreases, falling from 34% to 21%. The capacities of both natural gas combustion turbines (NG-CT) and natural gas combined cycle (NG-CC) increase because they are the least-cost generators for providing firm capacity and system flexibility using the Annual Energy Outlook's natural gas price estimates as described in Section 2.4. NG-CT capacity increases at a faster rate than NG-CC because NG-CT is the lowest-cost option when utilization factors are very low. In addition, 42 GW of energy storage is included in the system in 2015. In ReEDS, only diurnal storage is represented, which shifts energy across hours of the day, but not across seasons.

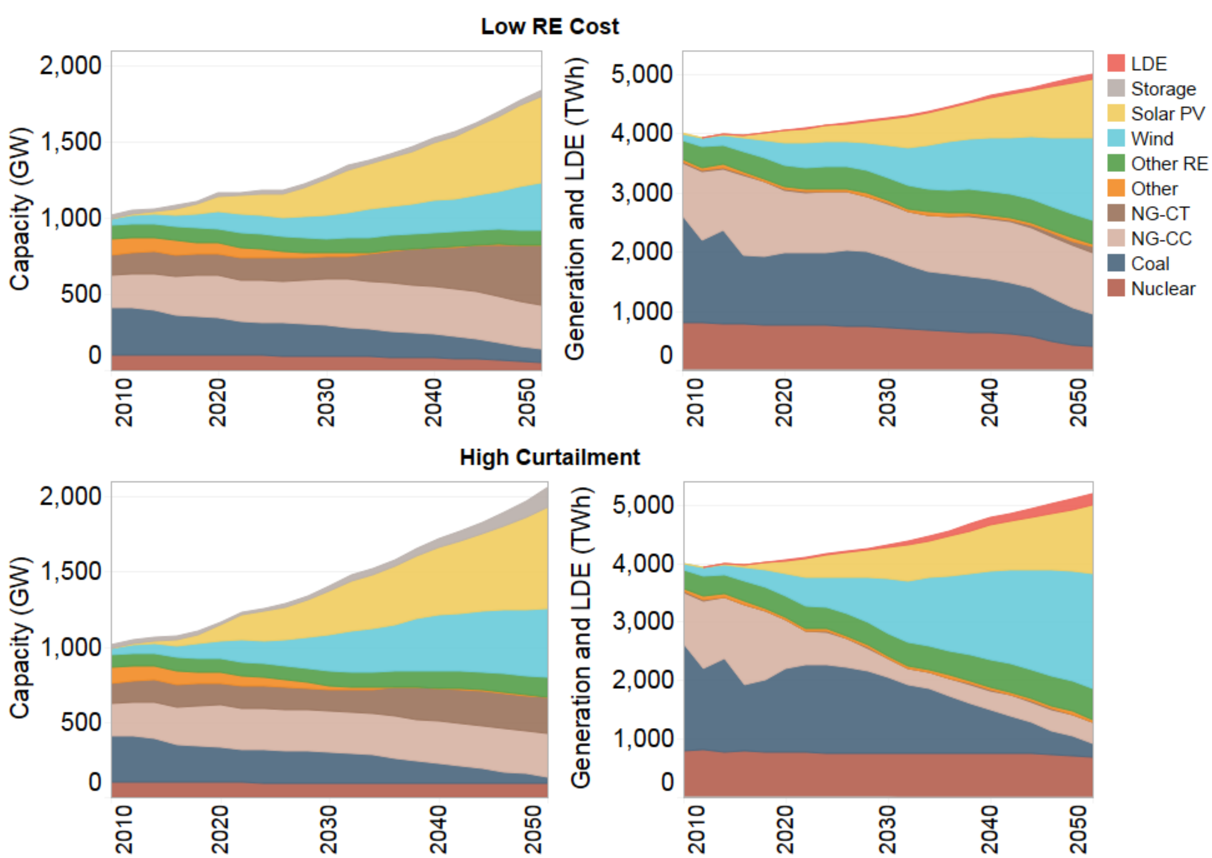

Figure 2. Capacity (left) and generation (right) evolution for the Low RE Cost scenario (top) and the High Curtailment scenario (bottom) (with a $0/MWh price for low-cost, dispatch-constrained electricity).

LDE is low-cost, dispatch-constrained electricity, NG-CT is natural gas combustion turbine, NG-CC is natural gas combined cycle, Other RE includes hydropower, geothermal, biopower, concentrating solar power, and landfill gas, and Other includes oil-gas-steam and imports.

In the High Curtailment scenario, wind and solar reach 61% of total generation in 2050, while natural gas makes up 7%. Nuclear generators have extended lifetimes in this scenario and continue to supply 680 TWh of energy in 2050—a 13% share. Due to the higher penetration of VRE and nuclear generation than in the Low RE Cost scenario, this scenario results in higher levels of curtailment, shown as "LDE" in Figure 2, reaching 200 TWh in 2050 (compared to 80 TWh in Low RE Cost). Additionally, higher levels of storage are deployed, with 130 GW of installed capacity in 2050.

Figure 3 and Figure 4 show the 2050 capacity and generation mixes at varying LDE prices. The data reported in the left bar in each image ($0/MWh LDE price) match the 2050 results in Figure 2, for the respective scenario. The remaining bars show the results at increasing LDE prices. Evolution figures like Figure 2 for each scenario and LDE price combination are provided in Appendix A.

Figure 3 shows that the potential LDE demand increases the installed capacity of both wind and PV due to the larger potential markets for these generators enabled by selling LDE, but only if the electricity prices are high enough. At higher LDE prices ($30/MWh and higher), the value of LDE becomes equal to or greater than the projected LCOE of wind or PV generation in some parts of the country (see Table 2), resulting in exponential growth. At those prices, the quantity of wind and PV generation capacity is limited by the resource availability and the cost to connect the sites to the transmission system (as it is at lower LDE prices). Results also show NG-CT installed capacity decreases at higher LDE prices, but these reductions are outweighed by the increases in wind and PV capacity; thus, the total generation capacity is larger.

Figure 4 shows how much the amount of available LDE increases at higher LDE prices. In the Low RE Cost scenario, we estimate LDE at around 2% of generation to serve load in 2050 at an LDE price of $0/MWh, representing only electricity that would otherwise be curtailed without a supplemental demand, but that quantity increases to 78% of generation to serve load at $30/MWh. The High Curtailment scenario results in higher levels of LDE; we estimate LDE at 4% of generation to serve load in 2050 at a price of $0/MWh, increasing to 89% at $30/MWh. The higher penetration of VRE in this scenario results in higher curtailment rates; therefore, compensating LDE has greater potential to impact VRE economics and incentivize increased penetrations of VRE, even at lower LDE prices.

While the total capacity and resulting generation of wind and PV increase with LDE prices, the generation mix to serve normal load (e.g., load before any assumed supplemental demands for LDE) remains relatively constant with increasing LDE prices. Those results indicate that paying for LDE may have limited impact on the generation used to serve load, but it may enhance the value proposition of existing wind and PV capacity.

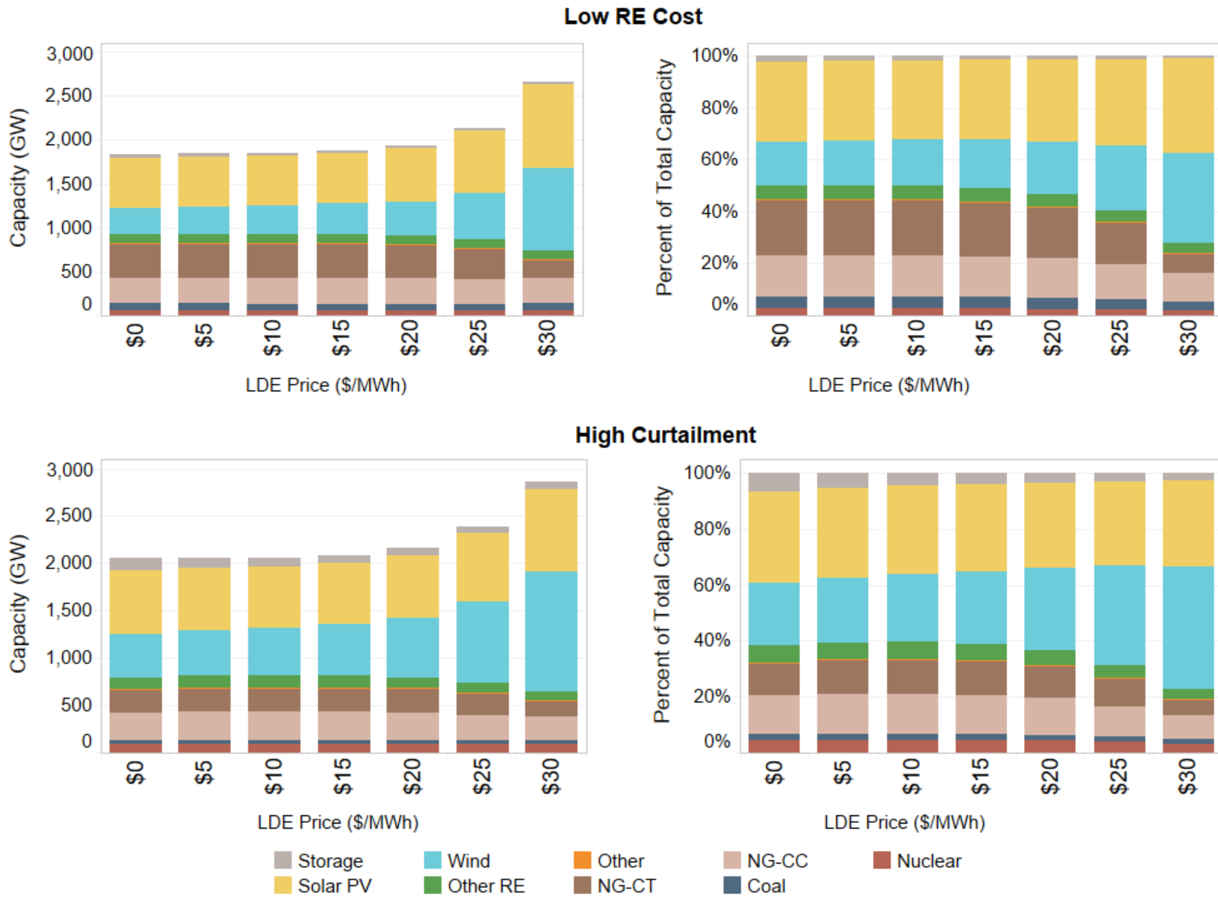

Figure 3. Capacity (left) and percent of total capacity (right) in 2050 at increasing low-cost, dispatch-constrained electricity prices ($/MWh) in the Low RE Cost scenario (top) and High Curtailment scenario (bottom).

LDE is low-cost, dispatch-constrained electricity, NG-CT is natural gas combustion turbine, NG-CC is natural gas combined cycle, Other RE includes hydropower, geothermal, biopower, concentrating solar power, and landfill gas, and Other includes oil-gas-steam and imports.

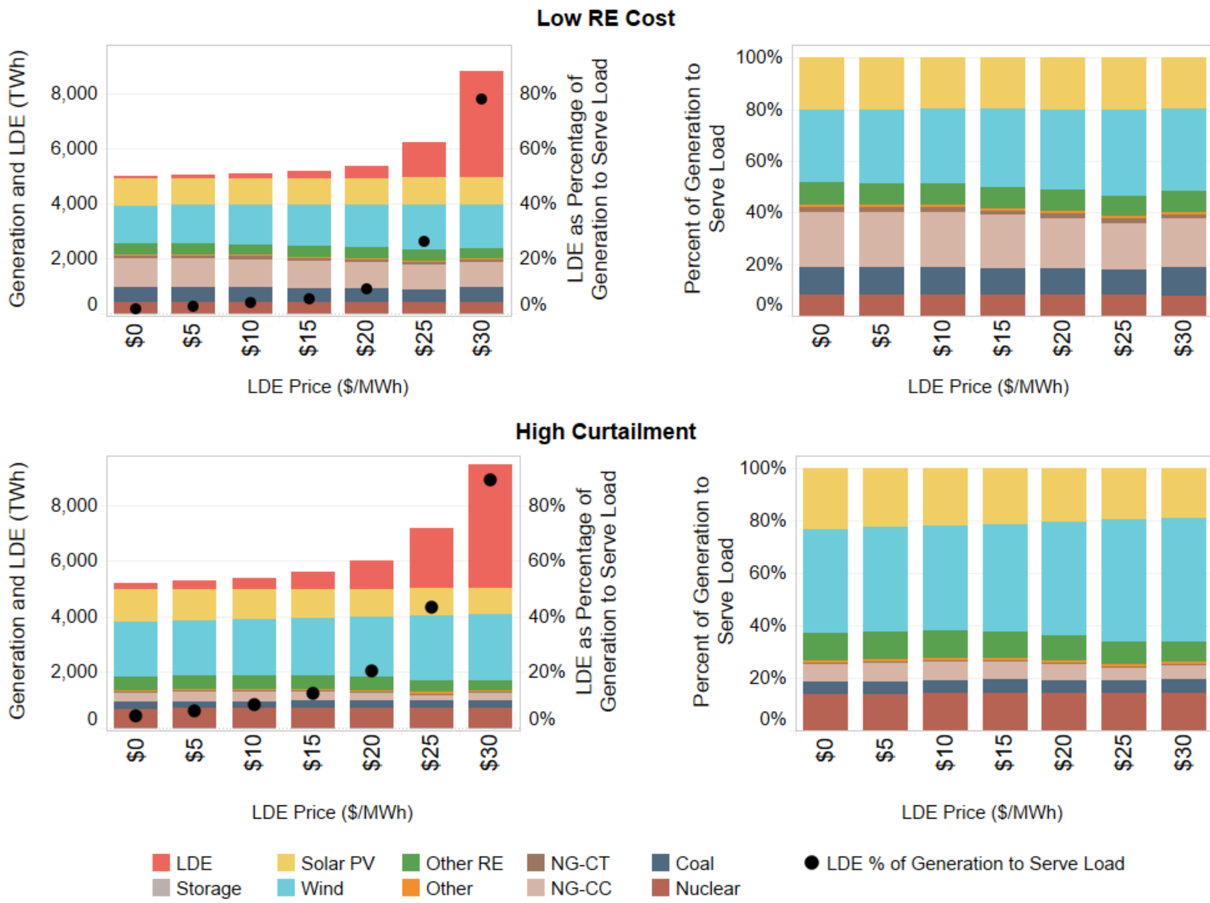

Figure 4. Generation (left) and percent of generation to serve load (right) in 2050 at increasing low-cost, dispatch-constrained electricity prices ($/MWh) in the Low RE Cost scenario (top) and High Curtailment scenario (bottom).

LDE is low-cost, dispatch-constrained electricity, NG-CT is natural gas combustion turbine, NG-CC is natural gas combined cycle, Other RE includes hydropower, geothermal, biopower, concentrating solar power, and landfill gas, and Other includes oil-gas-steam and imports.

3.2 Availability of Low-Cost, Dispatch-Constrained Electricity

The capacity mixes estimated from ReEDS are modeled in PLEXOS to analyze the temporal and spatial characteristics of the LDE. The estimated supply curves for the Low RE Cost and High Curtailment scenarios are shown in Figure 5. In the Low RE Cost scenario, we estimate around 100 TWh of LDE are available in 2050 at an LDE selling price of $0/MWh, but that quantity increases to 400 TWh and 3,500 TWh of LDE at $20/MWh and $30/MWh, respectively. For the High Curtailment scenario, we estimate close to 300 TWh of LDE are available in 2050 at a price of $0/MWh, increasing to 900 TWh and 4,200 TWh of LDE at prices of $20/MWh and $30/MWh, respectively. These values differ slightly from the ReEDS estimates (red bars in Figure 4) due to the differences in dispatch modeling between ReEDS and PLEXOS.

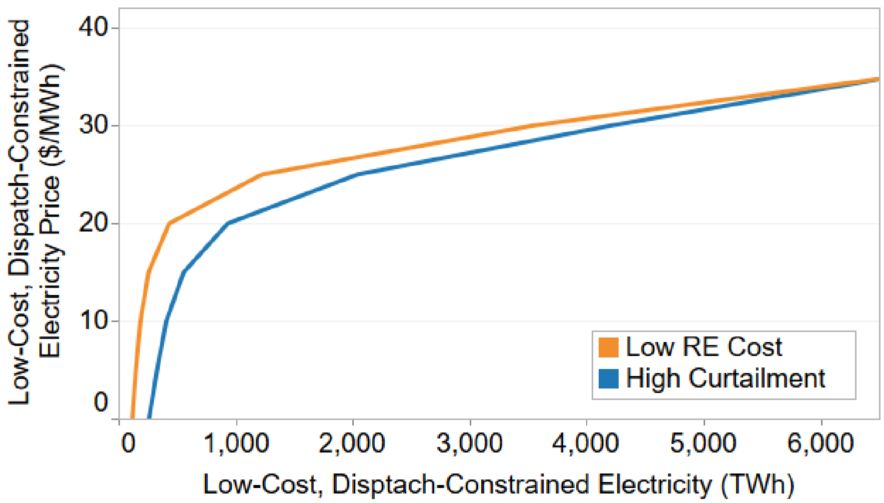

Figure 5. Supply curves of low-cost, dispatch-constrained electricity in 2050 for the Low RE Cost scenario (blue) and the High Curtailment scenario (orange)

The national-scale results show that 400–4,200 TWh of LDE is potentially available if it can be sold at $20–$30/MWh, depending on scenario assumptions; however, the quantity of LDE varies over time, at both hourly and seasonal scales. The temporal availability of LDE will impact whether and how this energy can be utilized economically in the variety of potential end uses. Figure 6 shows an LDE duration curve for the 8,736 hours of the year modeled in PLEXOS (PLEXOS only models 364 days of the year). The figure shows that while high total levels of LDE are possible, the availability of LDE is highly variable throughout the year. Using all energy accessible at a certain price could result in suboptimal utilization rates, so the capacity factors for equipment using the LDE decrease as more are installed. A system or equipment operator using the LDE could choose to downsize capacity for the benefit of increased effective capacity factors, but at a lower level of utilized LDE.

The tradeoff between the amount of electricity and effective capacity factor of that electricity on a national level is shown in Figure 7. The results show capacity factors of 7–40% if all available LDE is utilized, but could be much higher if some of that LDE is curtailed. The results also show that effective capacity factors above 80% are only achievable at LDE prices above $20/MWh in the Low RE Cost scenario, and above $15/MWh in High Curtailment. At lower prices, LDE is only available for limited hours during the year (as shown in Figure 6). For a given scenario and LDE price, improved effective capacity factors correspond to lower quantities of LDE. For example, in the High Curtailment scenario at a $20/MWh LDE price, only 25% of LDE can be utilized to achieve an effective capacity factor of 80%. Utilizing all available LDE in the same scenario would result in a 20% effective capacity factor. We note that higher utilization rates can be achieved in hybrid systems that purchase LDE when it is available below the threshold price and purchase higher-price electricity from the grid at other times, but this is outside the scope of the present analysis.

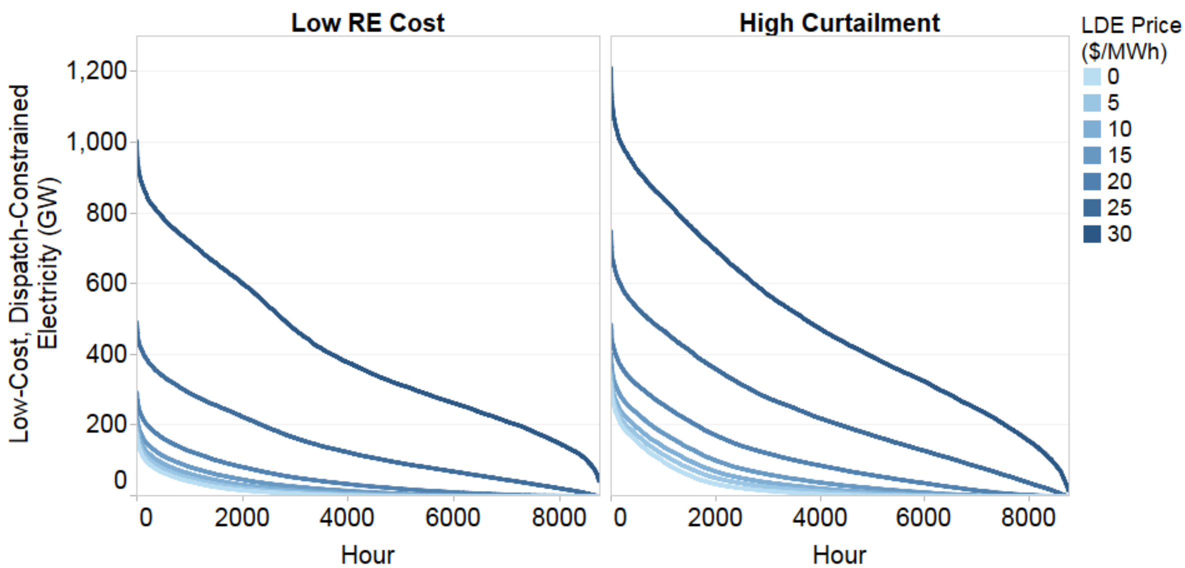

Figure 6. National duration curves in 2050 of low-cost, dispatch-constrained electricity for the Low RE Cost scenario (left) and the High Curtailment scenario (right).

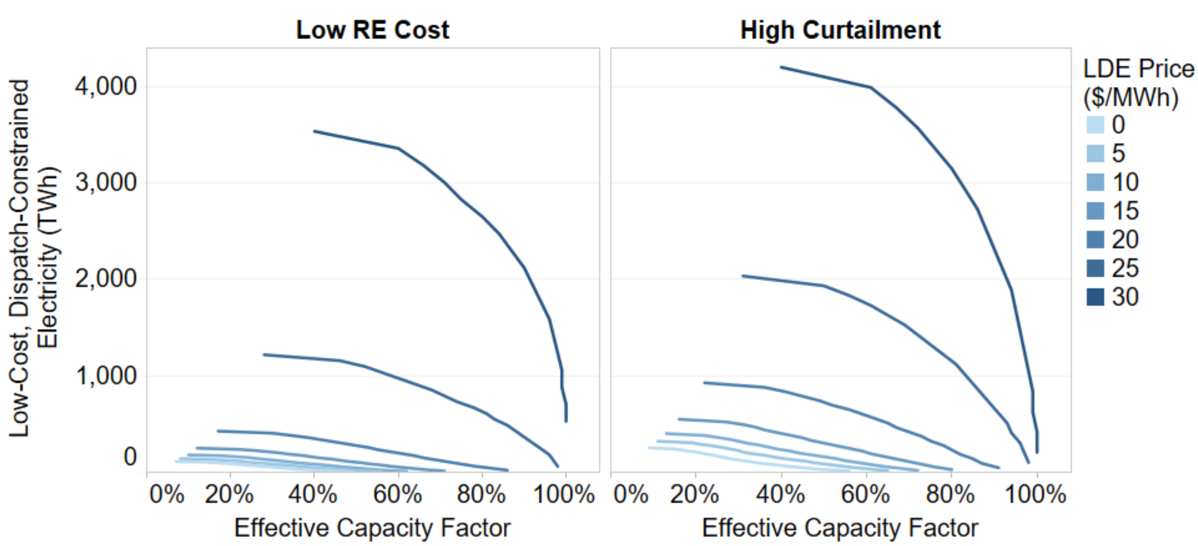

Figure 7. National effective capacity factor of LDE compared to annual LDE for the Low RE Cost scenario (left) and the High Curtailment scenario (right).

The availability of LDE throughout the year varies both seasonally and diurnally. In general, higher amounts of LDE are available in the spring and fall, when load on the grid is lower. At a daily level, LDE availability primarily follows the solar resource, with higher LDE availability in morning and afternoon hours. LDE in regions with primarily solar resources is mostly limited to these daytime hours, while regions with a mix of solar and wind resources may also have LDE available in the evening and overnight hours, although at lower levels than during the daytime. National and select regional LDE profiles are included in Appendix D.

The results presented thus far have been at a national scale, but the availability of LDE also varies geographically. Figure 8 shows the spatial distribution of LDE in 2050 at four LDE prices for the High Curtailment scenario. The available LDE is concentrated in areas with high wind and solar resources, namely the Central and Southwest United States. The potential uses of LDE and corresponding demand locations will impact the transmission requirements and/or constraints of utilizing the available LDE. High LDE demand on the East or West Coasts may require large infrastructure investments.

The effective capacity factors in Figure 8 are based on a 100% utilization of LDE. Lower utilization levels result in higher potential effective capacity factors. Appendix B includes similar charts for 80% utilization of LDE results for the Low RE Cost scenario, which exhibit similar geographic distribution as the High Curtailment scenario but at a lower magnitude of LDE.

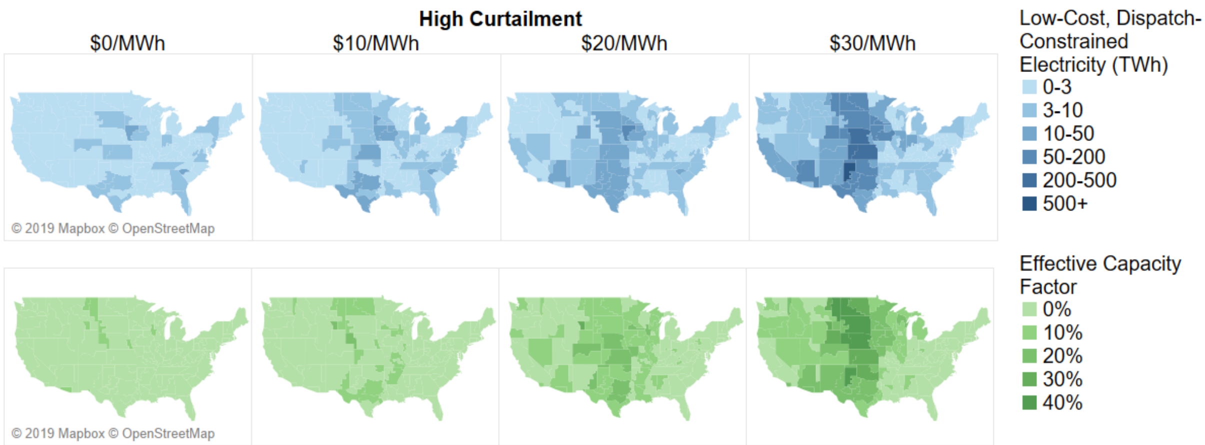

Figure 8. LDE available in 2050 by LDE price ($/MWh) (top) and the effective capacity factor of LDE (bottom) for each ReEDS balancing area in the High Curtailment scenario

The level of regional aggregation affects the calculated effective capacity factor of the estimated LDE resource. In general, larger aggregations of regions lead to higher effective capacity factors because the coincident temporal variability of the cumulative VRE resource decreases with the larger geographic scale. But in some cases, especially at lower LDE prices, certain regions with high VRE resource may have higher effective capacity factors than at a national level. To illustrate this, Appendix C includes results by Regional Transmission Organization (RTO). We note that larger geographic regions may have improved effective capacity factors but may require more infrastructure for transmission and distribution of the LDE.

4 Conclusions

VRE generation has been increasing, resulting in a higher prevalence of times and locations where generation is curtailed because generation exceeds load and power export is insufficient to overcome that difference. Additionally, price suppression can occur at higher penetrations of VRE, limiting growth. Some analysts are projecting increased levels of curtailment in the future, and researchers are identifying opportunities to use the resulting low-cost electricity. In this analysis, we endogenously calculate the quantity of LDE available at multiple prices in two scenarios using the ReEDS electricity system capacity expansion model and the PLEXOS production cost model. We also estimate the impacts a price of LDE might have on the generation mix. In the Low RE Cost scenario, we found that the amount of LDE available at a price of $0/MWh is 100 TWh annually, and that quantity increases to 3,500 TWh at $30/MWh. The High Curtailment scenario results in more LDE: 300 TWh annually at a price of $0/MWh, increasing to 900 TWh and 4,200 TWh of LDE at prices of $20/MWh and $30/MWh, respectively. Higher LDE prices increase the wind and solar PV fleet; however, other generation technology capacities do not decrease equivalently. Thus, additional generation is available, but it does not offset the NG-CC and NG-CT generation that provides firm, fixed capacity to the system. The LDE is concentrated in the Central and Southwest United States because of the high wind and solar resources in those regions. In addition, the availability of LDE varies on both seasonal and diurnal scales, resulting in low effective capacity factors (7–40% nationally) if all LDE is utilized.

5 Potential Future Work

This work presents initial estimates of future LDE availability that were developed in 2019. Thus, corresponding to cost assumptions and model version that may be out of date. This work could be updated to address those changes as well as those in technologies, costs, markets, and policies including the Inflation Reduction of Act of 2022.

In addition, further analysis is warranted to better understand the considerations of this resource. LDE availability and the resulting supply curves reported here are based on the ReEDS capacity expansion model and the PLEXOS production cost model for two future conditions. Additional scenarios could be considered, including ones with constrained carbon emissions; using alternative costs for batteries, other energy storage technologies, and generation technologies; considering impacts on adjacent sectors (e.g., a rebound effect on natural gas prices); or with transmission constraints. The impact of increased electrification and/or demand side flexibility could also be considered.

The scenarios presented here result in large increases in electricity generation compared to projected 2050 levels. These estimates assume market dynamics are such that sufficient demand is available to absorb all electricity generation. We do not consider market competition for LDE or potential price collapse due to market saturation, nor do we consider the impact on the effective LDE price of potential storage and transmission costs due to the regional and temporal variability of the resource. We also do not consider the full suite of impacts resulting in high levels of increased generation, including land use changes and impacts on energy markets.

Lastly, additional electricity market development is also likely needed. Current markets are usually not organized in ways that efficiently set the price for LDE and, in many markets, customers cannot access wholesale prices to be able to bid for this energy. Thus, for this concept to be applied, rules for those markets would likely need to be modified.

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Appendix A. Capacity and Generation Figures for Each LDE Price

Figure A-1 and Figure A-2 show results of the capacity buildout and generation for each modeled LDE price for the Low RE Cost and High Curtailment scenarios, respectively.

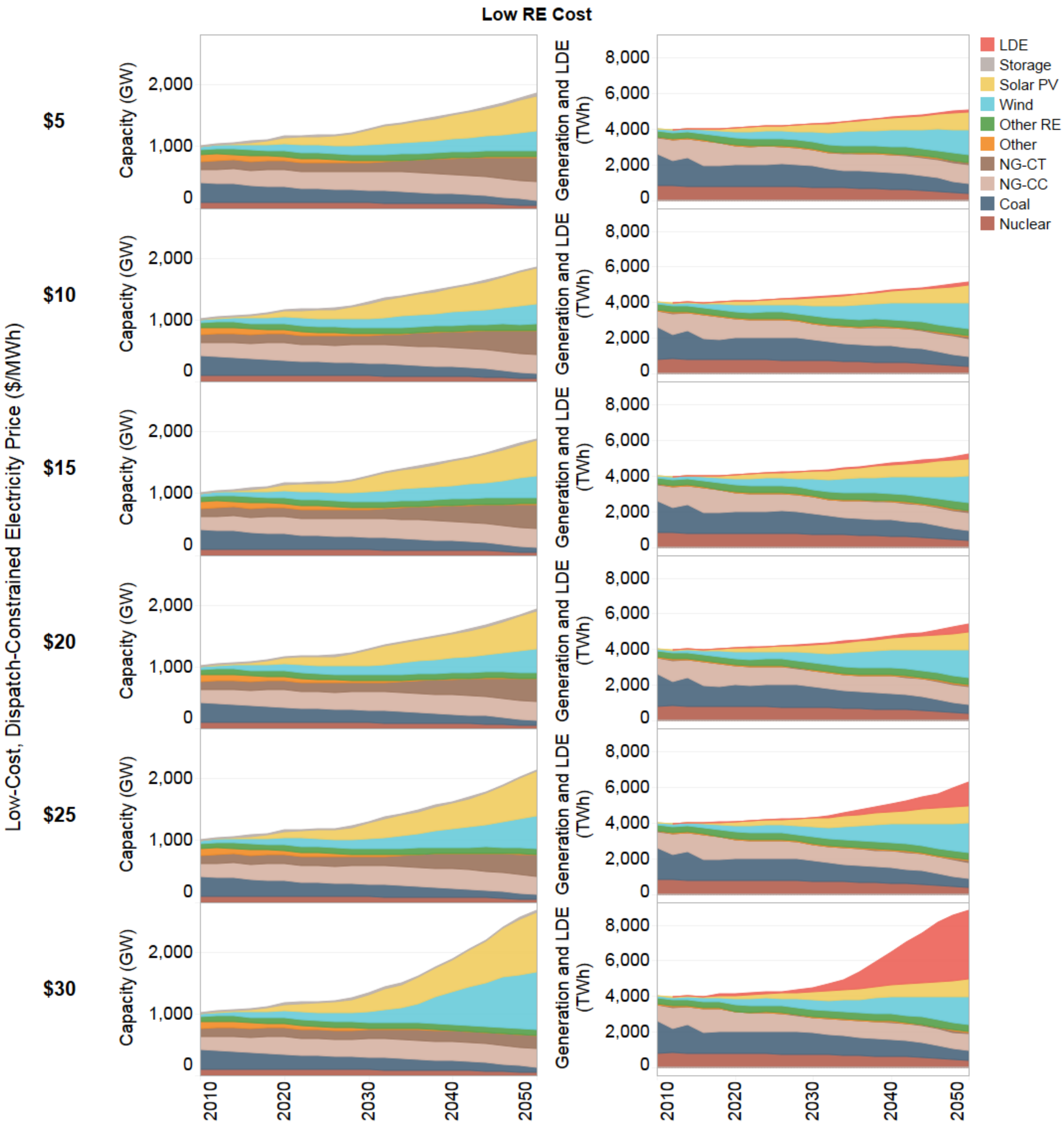

Figure A-1. Capacity (left) and generation (right) evolution for the Low RE Cost scenario with varying low-cost, dispatch-constrained electricity prices.

LDE is low-cost, dispatch-constrained electricity, NG-CT is natural gas combustion turbine, NG-CC is natural gas combined cycle, Other RE includes hydropower, geothermal, biopower, concentrating solar power, and landfill gas, and Other includes oil-gas-steam and imports.

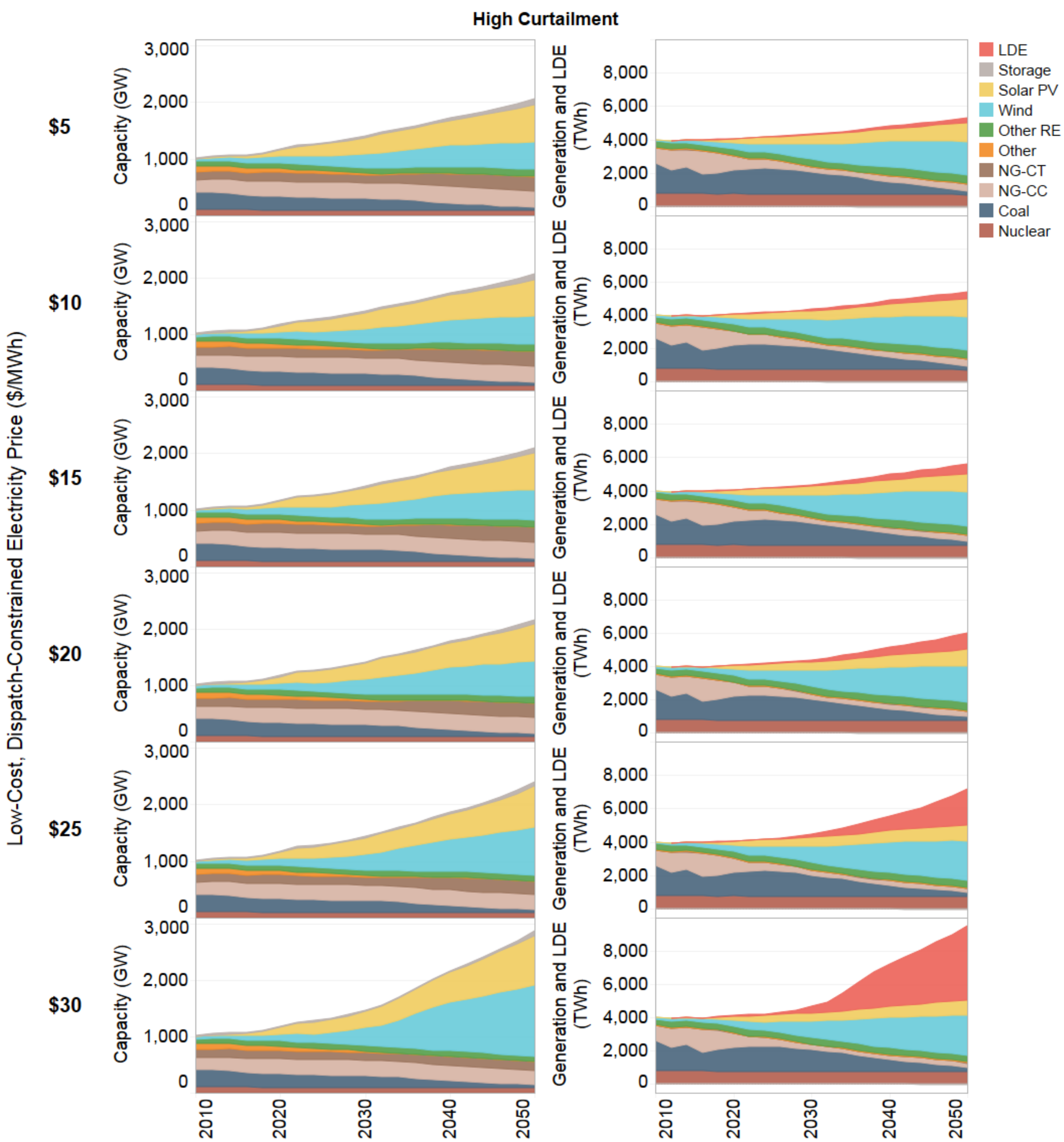

Figure A-2. Capacity (left) and generation (right) evolution for the High Curtailment scenario with varying low-cost, dispatch-constrained electricity prices.

LDE is low-cost, dispatch-constrained electricity, NG-CT is natural gas combustion turbine, NG-CC is natural gas combined cycle, Other RE includes hydropower, geothermal, biopower, concentrating solar power, and landfill gas, and Other includes oil-gas-steam and imports.

Appendix B. LDE Availability and Effective Capacity Factor by ReEDS Balancing Area

This section includes additional maps of LDE availability and the corresponding effective capacity factor by ReEDS balancing area. Figure B-1 and Figure B-2 show results for the Low RE Cost and High Curtailment scenarios assuming 100% of the LDE is utilized. Higher effective capacity factors of LDE can be achieved at lower LDE utilizations. Figure B-3 and Figure B-4 show results assuming only 80% of the LDE is utilized, which correspond to higher effective capacity factors, especially in regions with high VRE resource.

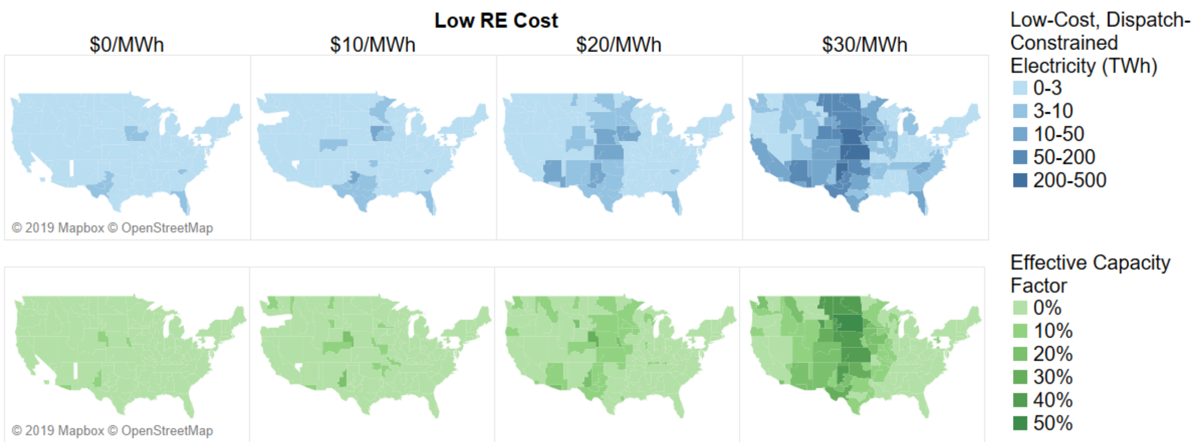

Figure B-1. LDE available in 2050 by LDE price ($/MWh) (top) and the effective capacity factor of LDE (bottom) for each ReEDS balancing area in the Low RE Cost scenario with 100% utilization of LDE

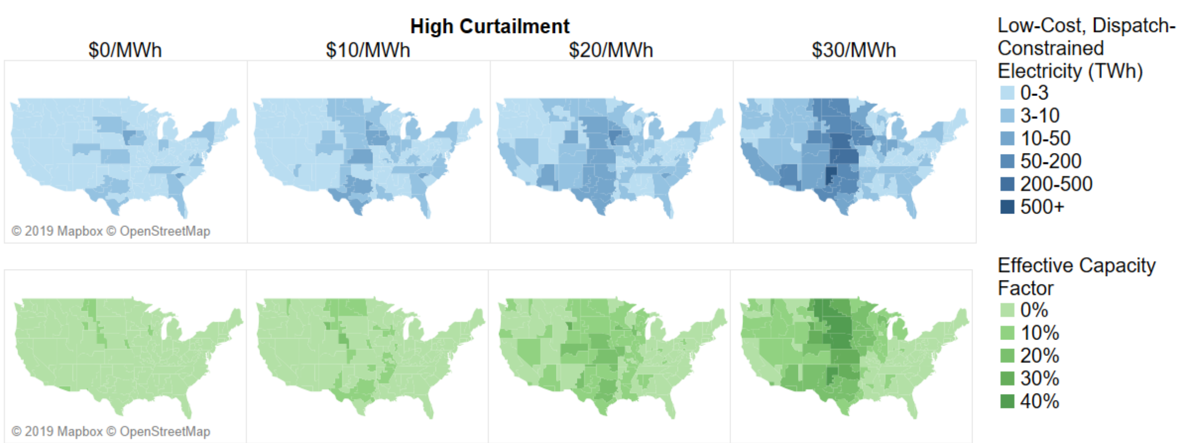

Figure B-2. LDE available in 2050 by LDE price ($/MWh) (top) and the effective capacity factor of LDE (bottom) for each ReEDS balancing area in the High Curtailment scenario with 100% utilization of LDE

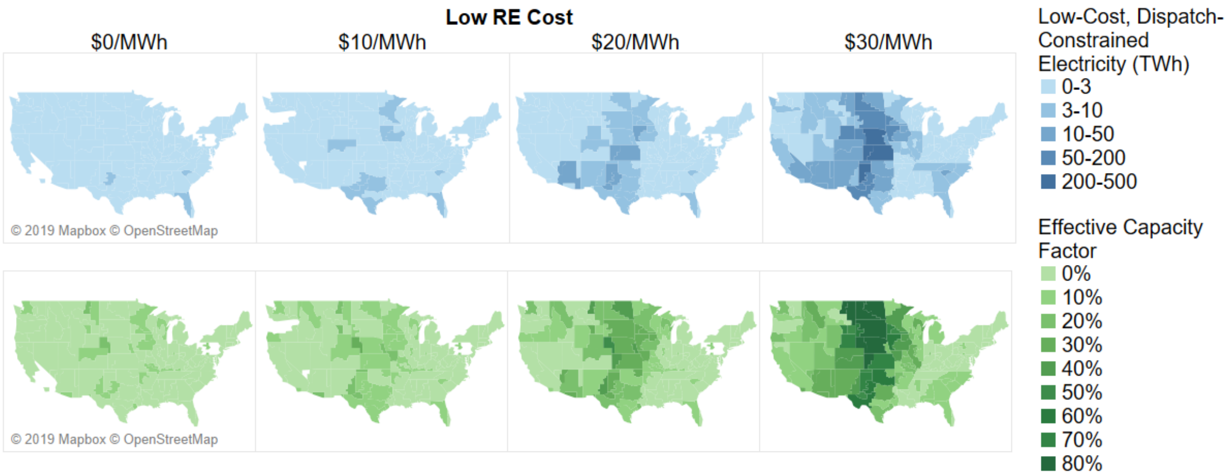

Figure B-3. LDE available in 2050 by LDE price ($/MWh) (top) and the effective capacity factor of LDE (bottom) for each ReEDS balancing area in the Low RE Cost scenario with 80% utilization of LDE

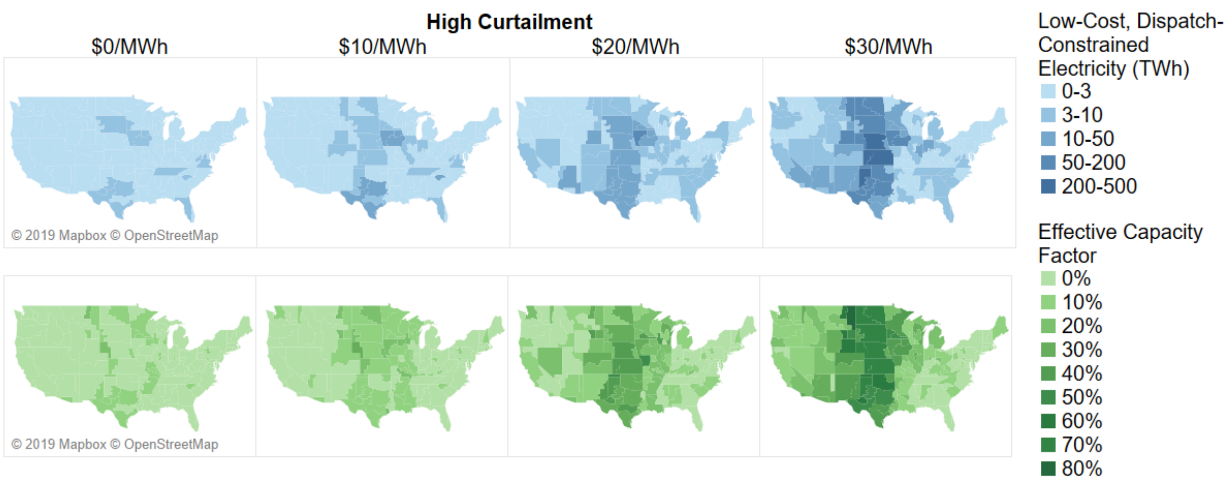

Figure B-4. LDE available in 2050 by LDE price ($/MWh) (top) and the effective capacity factor of LDE (bottom) for each ReEDS balancing area in the High Curtailment scenario with 80% utilization of LDE

Appendix C. LDE Availability and Effective Capacity Factor by ReEDS RTO

The effective capacity factor of LDE generally increases when the resource is aggregated across larger regions, as the coincident temporal variability decreases with the larger geographic scale. Considering LDE availability at a larger geographic scale requires the assumption that LDE can be transported across the region analyzed, from the source of supply to the point of consumption. This section includes LDE availability and effective capacity factors at the Regional Transmission Organization (RTO) level (see Figure C-1). Figure C-2 and Figure C-3 show results for the Low RE Cost and High Curtailment scenarios assuming 100% of the LDE is utilized. Higher effective capacity factors of LDE can be achieved at lower LDE utilizations. Figure C-4 and Figure C-5 show results assuming only 80% of the LDE is utilized, which correspond to higher effective capacity factors, especially in regions with high VRE resource.

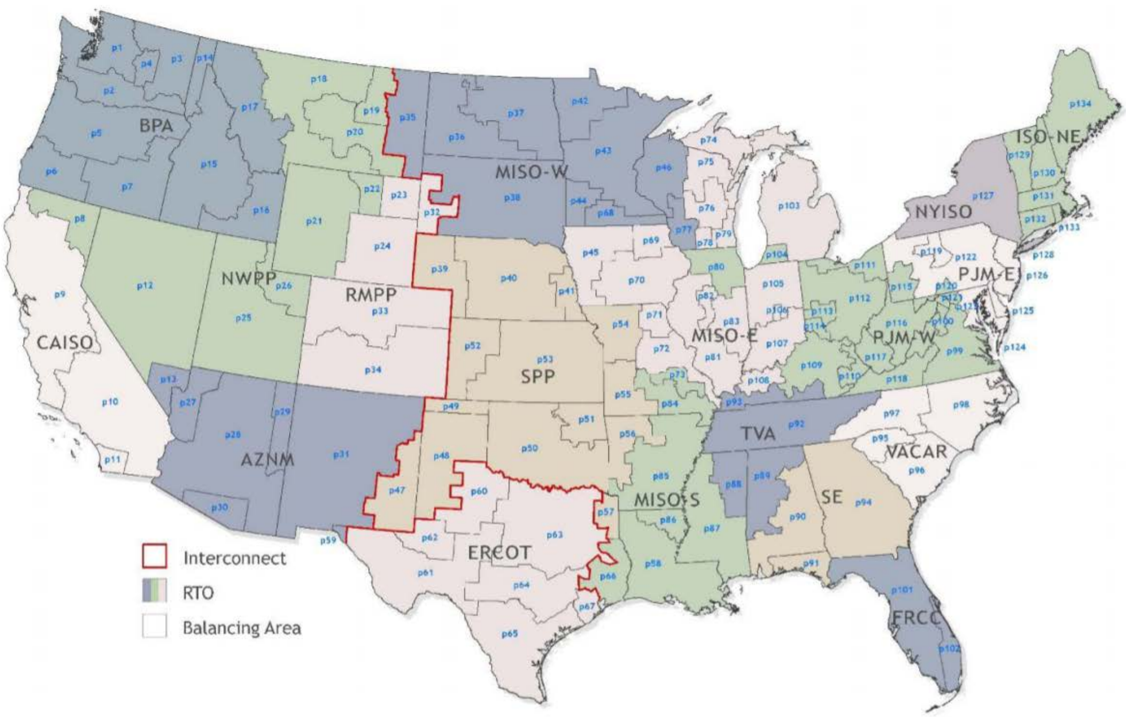

Figure C-1. Map of RTO regions (Eurek et al. 2016)

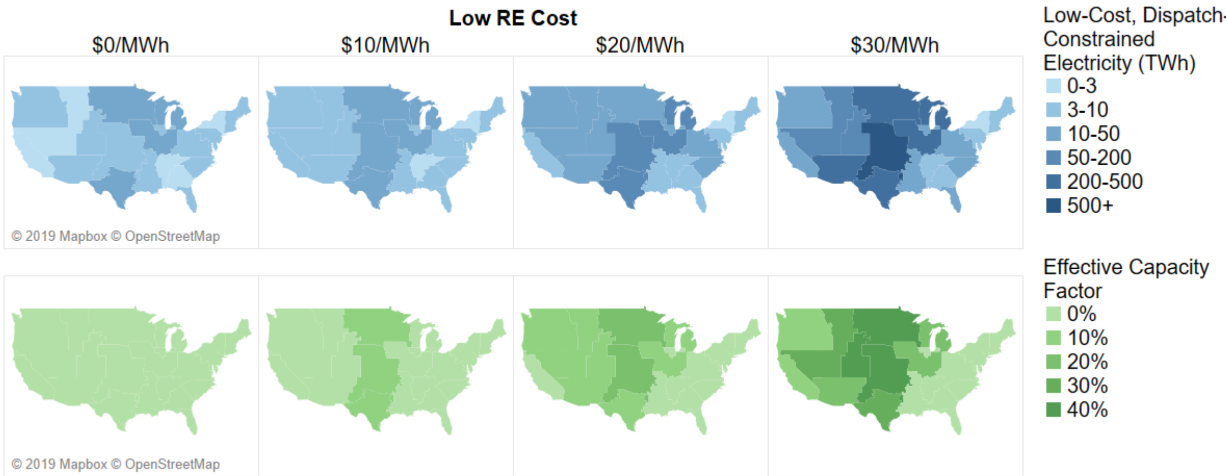

Figure C-2. LDE available in 2050 by LDE price ($/MWh) (top) and the effective capacity factor of LDE (bottom) for each RTO in the Low RE Cost scenario with 100% utilization of LDE

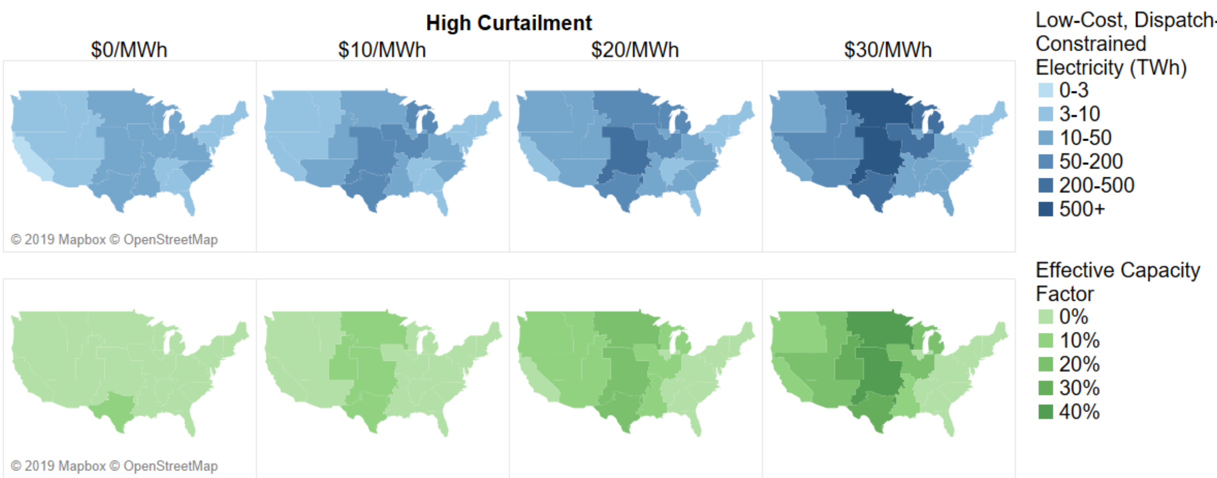

Figure C-3. LDE available in 2050 by LDE price ($/MWh) (top) and the effective capacity factor of LDE (bottom) for each RTO in the High Curtailment scenario with 100% utilization of LDE

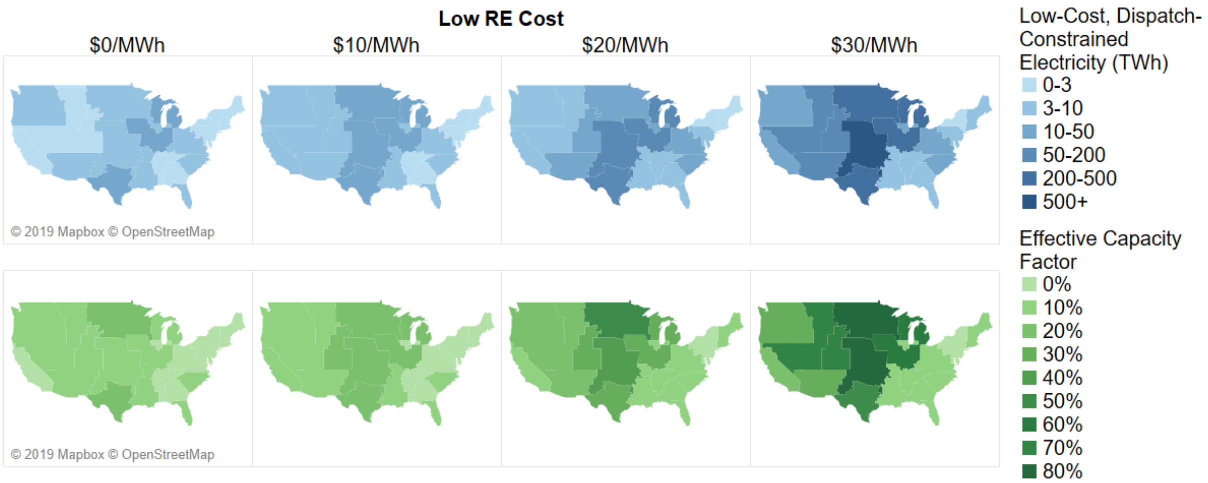

Figure C-4. LDE available in 2050 by LDE price ($/MWh) (top) and the effective capacity factor of LDE (bottom) for each RTO in the Low RE Cost scenario with 80% utilization of LDE

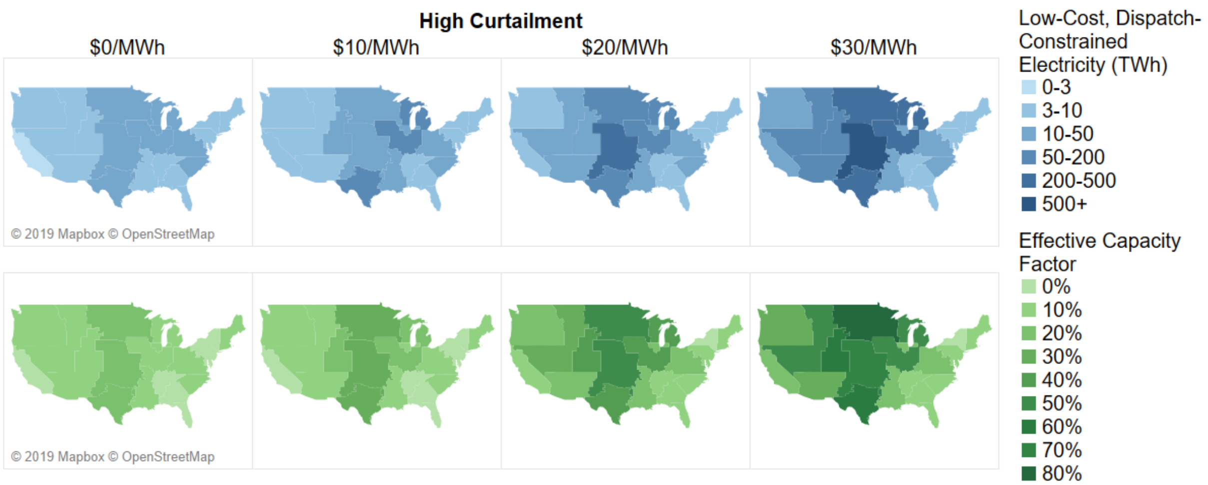

Figure C-5. LDE available in 2050 by LDE price ($/MWh) (top) and the effective capacity factor of LDE (bottom) for each RTO in the High Curtailment scenario with 80% utilization of LDE

Appendix D. Temporal Characteristics of LDE

The temporal profiles of LDE vary seasonally, diurnally, and regionally. Figure D-1 shows the average daily LDE availability for the Low RE Cost and High Curtailment scenarios for select months of the year representing the various seasons. Figure D-2 shows the average daily availability of LDE in the High Curtailment scenario for two regions: one region in the Southwest United States with high solar resource, and the second is an RTO in the Central United States with wind-dominant VRE resource.

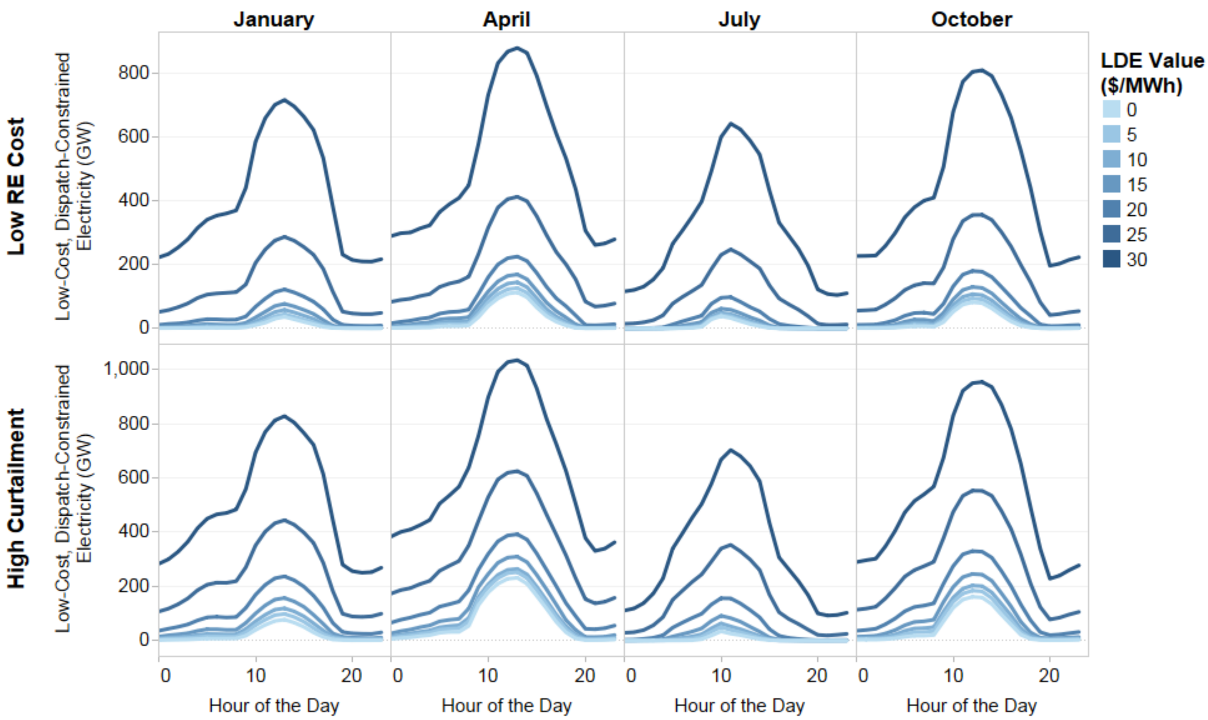

Figure D-1. Average daily generation of LDE in the Low RE Cost scenario (top) and the High Curtailment scenario (bottom) for select months of the year.

Note the difference in y-axis scales between scenarios.

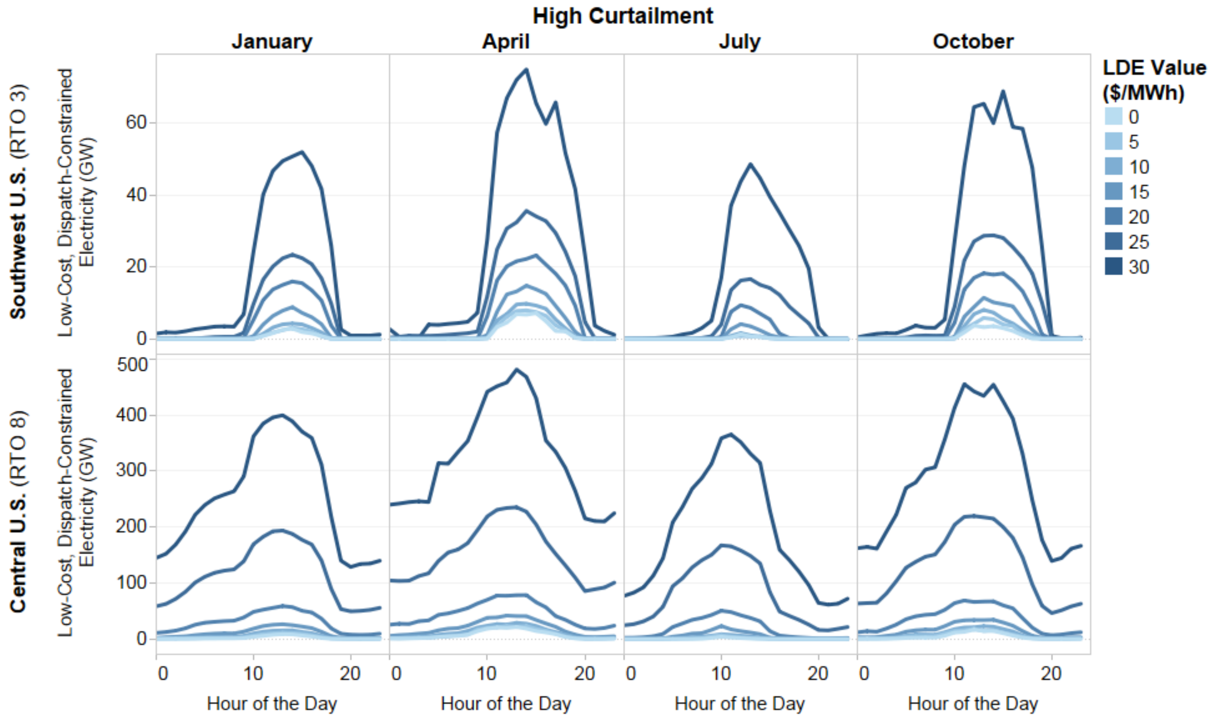

Figure D-2. Average daily generation of LDE in the High Curtailment scenario for an RTO in the Southwest U.S. (top) and an RTO in the Central U.S. (bottom) for select months of the year.

Note the difference in y-axis scales between RTOs.

Appendix E. Impacts of Methodological Differences Between ReEDS and PLEXOS Models

The modeling methodology used in this analysis to estimate LDE availability at various prices is described in Section 2. The compensation for LDE generation is represented in the ReEDS capacity expansion model to estimate the generator fleet resulting from the additional LDE revenue stream. We input the 2050 generator fleet and transmission expansion from ReEDS into PLEXOS to model hourly operation. PLEXOS also estimates the hourly locational marginal price (LMP) of generated electricity. The implicit assumption in our modeling is that LDE generation would occur during hours where the LMP is less than the price of LDE, since a generator could increase revenue through compensation for LDE compared to selling to the grid. Here we compare the modeled electricity prices in PLEXOS with the assumed LDE prices to validate the modeling methodology.

For validation, we compare the hourly LMPs calculated in PLEXOS with the assumed LDE prices to identify whether our estimates of the quantity of LDE in each hour, based on ReEDS results, are similar to those calculated using PLEXOS without a price floor, as shown in Figure E-1. The LDE is reported for four LDE prices used in the ReEDS model to determine the generation fleet: \$0/MWh, \$10/MWh, \$20/MWh, and \$30/MWh. The amount of LDE is sorted from largest to smallest to develop LDE duration curves. At all four LDE prices, the quantity is similar between ReEDS and PLEXOS, with PLEXOS estimating more LDE during the hours with high LDE availability and less LDE during hours with low LDE availability (left panel of Figure E-1). The middle panel in Figure E-1 reports nationally weighted average price duration curves from PLEXOS for the same four generation fleets. Lastly, the right panel compares the percent of hours during the year when the PLEXOS-calculated national weighted average LMP is lower than the LDE price used in ReEDS with the PLEXOS-calculated percentage of hours during the year when generation exceeds load (i.e., LDE is available). Since, at a national average, the number of hours when generation exceeds load is greater than the number of hours when the price is below the LDE price, we conclude that, in general, on-demand generators (e.g., natural gas and coal-powered units) would not increase generation for LDE demands. There is available energy that exceeds load during those hours, and thus, there is no incentive to pay for fossil resources to generate additional electricity.

Figure E-1 shows results at the national level; however, results vary when considering lower levels of geographic aggregation. For example, unlike the national average, at the RTO level, some of the RTO-LDE price combinations have more hours when the LMP is less than the LDE price than hours when generation exceeds load not including LDE. Figure E-2 compares the number of hours where the average LMP is less than the LDE price with the number of hours that both meet this condition and have LDE generation. In many RTOs, LDE generation occurs in most hours where the LMP is less than the LDE price. This is especially apparent for RTOs with high LDE generation, which correspond to regions with high wind resources. The RTOs with fewer hours of LDE generation than hours with LMPs lower than the LDE price generally have low wind resource and low LDE generation (small circles in Figure E-2); thus, hours with high PV penetration (and low LMPs) occur during periods of high afternoon load with less opportunity for overgeneration. At almost all LDE prices for those RTOs with high levels of LDE, the hours when generation exceeds load are greater or equal to the hours with LMPs less than the LDE price used to develop the generation fleet. Thus, our conclusion stands: on-demand generators (e.g., natural gas and coal-powered units) would not increase generation for LDE demands. There is available energy that exceeds load during those hours, and thus, there is no incentive pay for fossil resources to generate additional electricity.

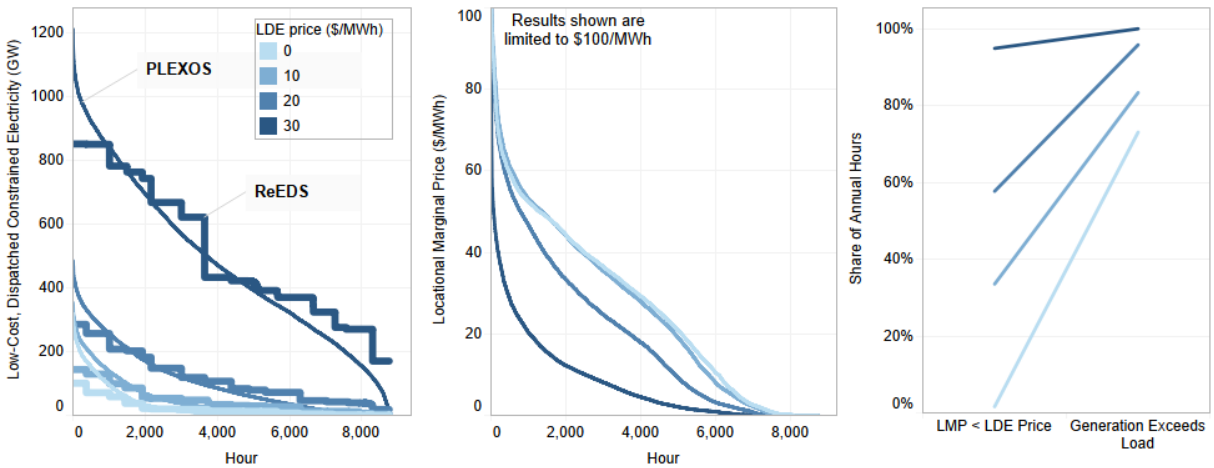

Figure E-1. National-level comparison of LDE duration curves between ReEDS and PLEXOS (left); resulting price duration curves from PLEXOS (middle); and comparison between fraction time when PLEXOS-estimated LMPs are below the LDE price used to set the generation fleet and generation exceeds load not including LDE (right)

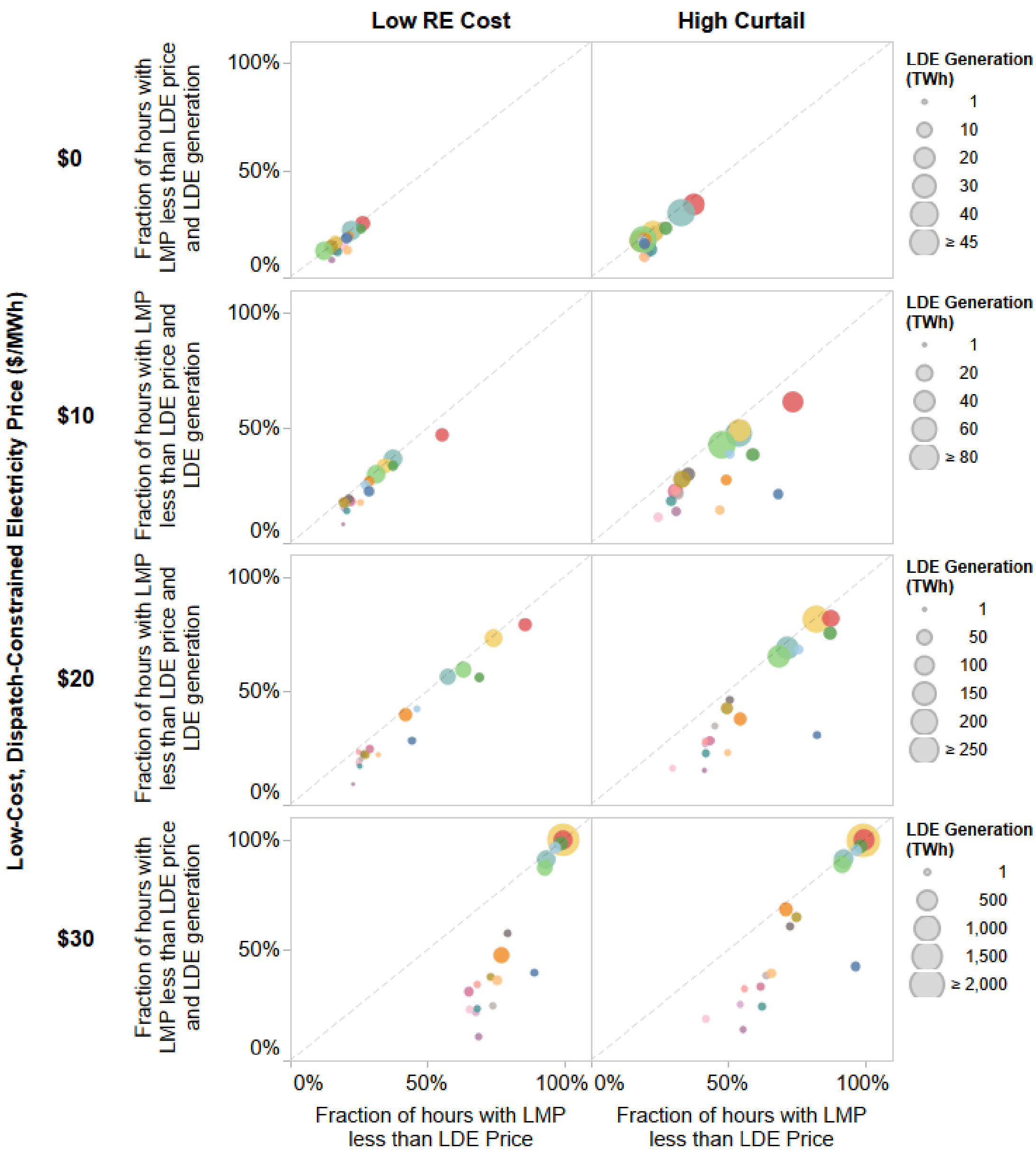

Figure E-2. Fraction of modeled hours with average LMP below LDE price compared to fraction of hours with average LMP below LDE price and also LDE generation.

Note the differences in scale of the legend sizes. Each circle represents a distinct RTO. LDE is low-cost, dispatch-constrained electricity; LMP is locational marginal price.