FOSSIL FLEET TRANSITION WITH FUEL CHANGES AND LARGE SCALE VARIABLE RENEWABLE INTEGRATION

Final Technical Report

DOE-EPRI-OE0000614

Period Covered: October 2013 – March 2015

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Program on Technology Innovation: Fossil Fleet Transition with Fuel Changes and Large Scale Variable Renewable Integration

3002006517

Final Report, September 2015

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***DOE Acknowledgment*: This material is based upon work supported by the Department of Energy under Award Number DE-OE0000614.**

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ACKNOWLEDGMENTS

The Electric Power Research Institute (EPRI) prepared this report.

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This report describes research sponsored by EPRI.

The authors would like to gratefully acknowledge the support of the Offices of Electricity, Fossil Energy, and Energy Efficiency & Renewable Energy of the U.S. Department of Energy for supporting this research (DOE DE-OE0000614). We would also like to acknowledge the technical oversight and guidance provided by Dr. Caitlin Callaghan (Office of Electricity and Energy Reliability), Charlton Clark (Office of Energy Efficiency & Renewable Energy), and Douglas Middleton (Office of Fossil Energy).

Several EPRI staff members contributed comments and insights to this project and the final report:

- Engineering Subject Matter Experts: Sherry Bernhoft, Michael Caravaggio, Bill Carson, Dwayne Coffey, Kent Coleman, Neva Espinoza, Susan Maley, Dr. Jeffrey Phillips, Merrill Quintrell, Rick Roberts, Dr. Robert Steele.
- Energy-Economic Modeling team: Dr. Francisco de la Chesnaye, Dr. David Young, Dr. Geoff Blanford
- Grid Integration and Performance: Dr. Aidan Tuohy

Finally, this project would not have come to fruition without the leadership and vision of Larry Mansuetti (DOE) and Stuart Dalton (EPRI).

This publication is a corporate document that should be cited in the literature in the following manner:

Program on Technology Innovation: Fossil Fleet Transition with Fuel Changes and Large Scale Variable Renewable Integration. EPRI, Palo Alto, CA: 2015. 3002006517.

PRODUCT DESCRIPTION

Variability in demand as seen by grid-connected dispatchable generators can increase due to factors such as greater production from variable generation assets (for example, wind and solar), increased reliance on demand response or customer-driven automation, and aggregation of loads. This variability results a need for these generators to operate in a range of different modes, collectively referred to as “flexible operations.” This study is designed to inform power companies, researchers, and policymakers of the scope and trends in increasing levels of flexible operations as well as reliability challenges and impacts for dispatchable assets.

Background
Because there is rarely a direct monetization of the value of operational flexibility, the decision to provide such flexibility is typically dependent on unit- and region-specific decisions made by asset owners. It is very likely that much greater and more widespread flexible operations capabilities will be needed due to increased variability in demand seen by grid-connected generators, uncertainty regarding investment in new units to provide adequate operational flexibility, and the retirement of older, uncontrolled sub-critical pulverized coal units.

Objective
To enhance understanding of the technical challenges and operational impacts associated with dispatchable assets needed to increase operational flexibility and support variable demand.

Approach
The study approach consists of three elements: a literature review of relevant prior studies, analysis of detailed scenarios for evolution of the future fleet over the next 35 years, and engineering assessment of the degree and scope of technical challenges associated with transformation to the future fleet. The study approach integrated two key elements rarely brought together in a single analysis—1) long-term capacity planning, which enables modeling of unit retirements and new asset investments, and 2) unit commitment analysis, which permits examination of hourly unit dispatch while considering operational limitations relevant to flexible operations capabilities.

Results
The three key dimensions of systemic challenges in terms of variable generation include the following:

- Increased unit operations and maintenance costs due to equipment damage resulting from flexible operations
- Impacts on unit emissions and ability to maintain compliance with environmental regulations
- Technical challenges associated with providing flexible operations capabilities across a large number and variety of dispatchable generation assets

Driven by existing regulatory policies (including renewable portfolio standards) and fuel prices, significant levels of renewable electricity generation (11%–41% of total generation) are likely to emerge by 2050. Despite variations in the generation technology mix in different regions of the U.S., this study indicates that widespread high levels of flexible operations will be necessary across most regions for much of the year by 2050. Also predicted are frequent, large changes in average hourly generation for combustion turbine combined-cycle and coal assets as well as significant periods of low-load operations and reserve standby.

Applications, Value, and Use

The feasibility of achieving the very high levels of operational flexibility across the generation fleet as shown in this study is highly uncertain without additional technical capabilities related to equipment monitoring and maintenance, and development of viable operational strategies. Such capabilities are necessary to enable increased flexible operations, expand inter-regional transmission capacity, and advance economic drivers that incentivize asset owners to invest in creating greater unit flexibility.

Keywords

Flexible operation
Variable generation
Energy analysis
Fossil fleet transition
Fossil generation
Unit commitment
Renewable integration

EXECUTIVE SUMMARY

This study is designed to inform power companies, researchers, and policymakers regarding scope and trends in increasing engineering, operations, and reliability impacts for dispatchable assets experiencing an increasingly wider range of different operating modes (collectively referred to as "flexible operations.") resulting from increased variability in demand as seen by these assets. This variability in demand can increase due to several factors, such as increased production from variable generation assets (e.g. wind and solar), increased reliance on demand response or customer-driven automation and aggregation of loads.

While the principal area of interest in prior studies has typically been an evaluation of the feasibility of high levels of renewable energy generation and the necessary conditions to support those levels of deployment, the objective of this study is to provide a better understanding of technical challenges and operational impacts for dispatchable assets whose operations become increasingly flexible in support of variable demand as seen by those assets. Prior research regarding deployment, integration and operations of renewable assets is typically based on assumptions about operational capabilities of dispatchable generation assets. This study integrates a comprehensive assessment of the composition of the future generation fleet with industry knowledge and experience regarding the physical effects of increased flexible operations on generation assets.

A better understanding of the long-term impacts of flexible operations demand placed on the power system requires integrating an assessment of how the composition of the generation fleet changes as units retire and investments in new units are made with an evaluation of the impacts of future changes in flexible operations on dispatchable generation assets. To accomplish this, the study approach consists of three elements: a literature review of relevant prior studies, analysis of detailed scenarios for evolution of the future fleet over the next 35 years, and engineering assessment of degree and scope of technical challenges associated with transformation to the future fleet.

Prior Studies Recognize Need for Substantial Future Flexible Operations

Substantial prior research (e.g. regional interconnection studies) has examined several aspects of increasing renewable electricity generation: renewable asset integration, reliability impacts, and potential cost and emissions impacts. From the perspective of increasing demand for flexible operations by dispatchable assets, literature review of prior research provided valuable insights:

- How to best understand and define flexible operations - e.g. definition of specific flexible operations modes (such as two-shifting), frequency and number of start/stops, ramp rates, required levels of low unit output
    - Generally, the pattern of increasing flexible operations and operational challenges associated with increasing variability in demand (as seen by dispatchable, grid-

connected assets) is consistent between the results of this project, EPRI research, and research by others.

- Understanding cost impacts of flexible operations – e.g. lost generation, lower efficiency, reduced availability, added O&M costs, added capital costs

While generically applicable modeling of costs impacts is difficult, both EPRI and other research identify similar damage mechanisms caused by flexible operations.

- Understanding the impact of flexible operations on unit dispatch and operations.
    - The capabilities of transmission system expansion and energy transfer between regions in response to flexible operations demands are clearly critical factors affecting the future composition of the generation fleet.
    - The key unit operational capabilities central to flexible operations are minimum output levels, and up and down ramping capabilities, and unit start times.
- Key insights relative to analysis/ modeling
    - Modeling minimum load and ramping capabilities/limitations is essential for understanding the impact of flexible operations on future fleet transformation.
    - In addition to assuring adequate flexible operations capabilities, the future generation fleet may also be challenged to expand in response to sustained moderate demand growth.

The literature review thus informed scenario definition and underlying assumptions for this study, as well as helped to define key issues meriting specific attention in the modeling and analysis process.

Study Integrates Modeling of Long-Range Fleet Transformation with Unit Dispatch

Barring significant technology developments in energy storage, previous research clearly indicates that dispatchable generation assets (principally combined cycle gas turbines and coal units) will have to operate much more flexibly in a system with high levels of renewable electricity generation. Understanding the technical implications of an increased demand for flexible operations requires an assessment the future composition of the generating fleet and how it is likely to be dispatched. The lifetime of power generating assets is sufficiently long to warrant increased focus on prediction of future asset dispatch characteristics, such as is being done in this project. Asset design attributes must match future, not just current needs. Based on this assessment, an engineering evaluation of the scope and nature of flexible operations is possible, thus enabling a discussion of specific technical challenges requiring technology and operational solutions.

Figure 1 outlines the overall modeling and analysis approach to achieving the steps as described above. Key aspects and results of the study are briefly discussed in this summary.

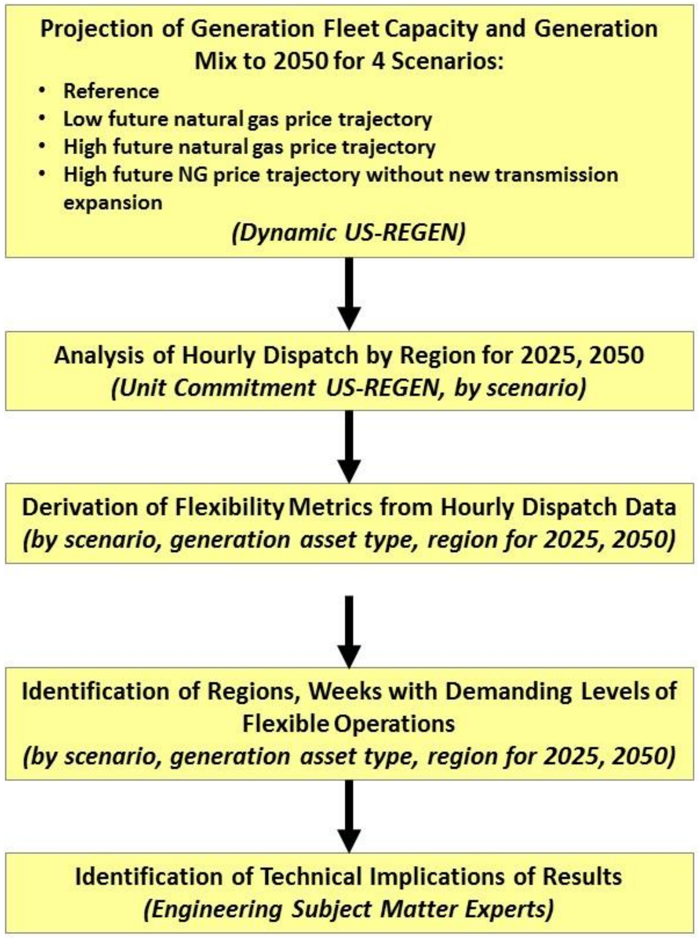

Figure 1: Overview of Analysis Approach

Key Sensitivities are Future Natural Gas Prices and Ability to Add New Transmission

The importance of gas-fired power plants as a potential resource for flexible operations clearly suggests that sensitivity of the future generation fleet to natural gas prices should be explored. Regional differences in demand, generation fleet composition, and availability of renewable resources suggests that inter-regional transmission is also a very important aspect of the response to increased demand for flexible operations (note that intra-regional transmission and distribution are not considered in this study). The importance of these issues are confirmed in several key interconnection studies and other reports included in the literature review.

Therefore, this study defined four key scenarios:

- Reference scenario (principally based on assumptions consistent with the U.S. Energy Information Agency's 2014 Annual Energy Outlook) (EIA 2014)
- Low gas price trajectory scenario
- High gas price trajectory scenario
- High gas price trajectory + no new inter-regional transmission expansion

Future Generation Share of Renewables will be Much Larger

Modeling of long-term changes in the future generation fleet was performed using EPRI's US-REGEN (U.S. Regional Economy, Greenhouse Gas, and Energy) dynamic model. US-REGEN models several characteristics particularly important to understanding the potential impact of increasing renewable electricity generation on the need for flexible operation of dispatchable assets:

- Inter-regional differences in demand and transmission inter-connection (see Figure 2),
- Long-term (i.e. out to 2050) transformation of the generation fleet through retirements and new asset development, and
- Geographical/temporal variations in renewable resource availability.

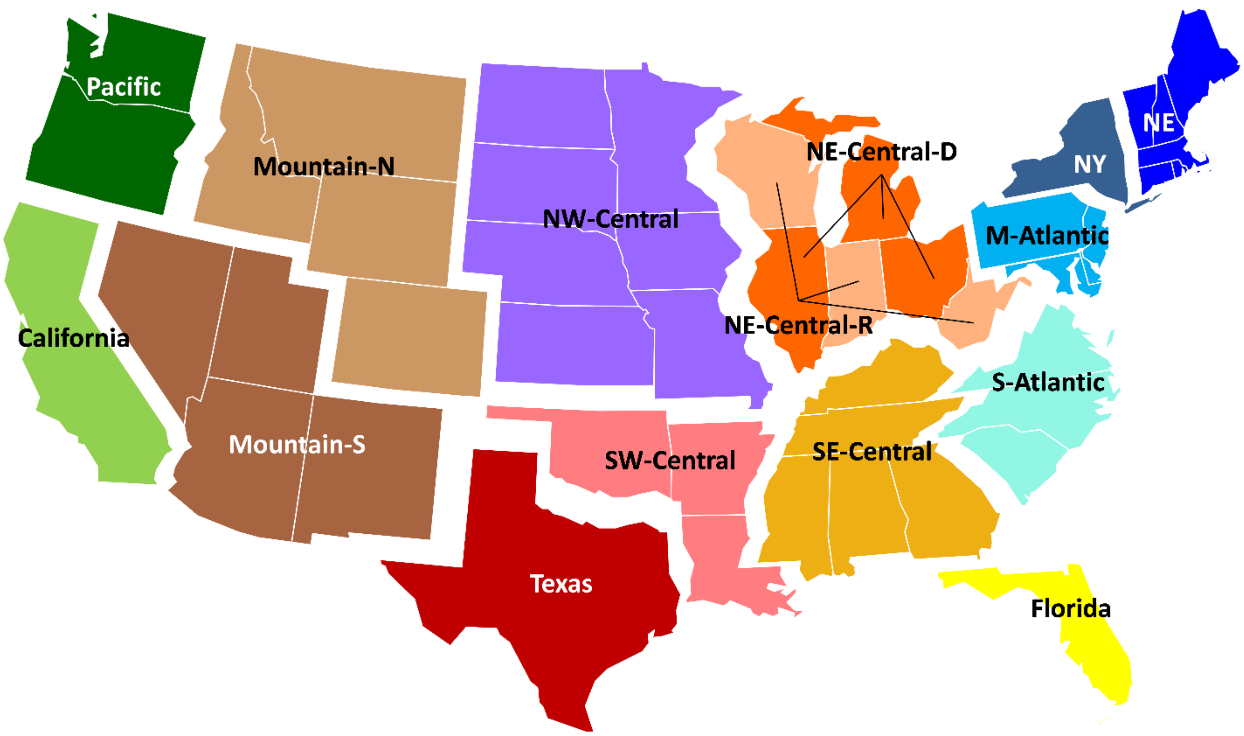

Figure 2: Regional Structure of US-REGEN Model

The generation results of the US-REGEN dynamic model analysis for the four scenarios are captured in Figure 3. (Note that “environmental retrofit” refers to coal that was retrofitted for compliance with existing regulations assumed as defined in the reference scenario.) While these results cannot be viewed as predictive, it is clear that future levels of electricity generation from renewable energy resources will be substantially larger than today. Even the low future natural gas price scenario ultimately reaches non-hydro renewable generation shares on the order of 11% of total U.S. generation, roughly double current levels. The other scenarios result in 2050 renewable non-hydro generation shares ranging from 28%-41%. Consequently, the future generation fleet is likely to have much more variable generation, which is very likely to require substantially more flexible operations by dispatchable generation assets.

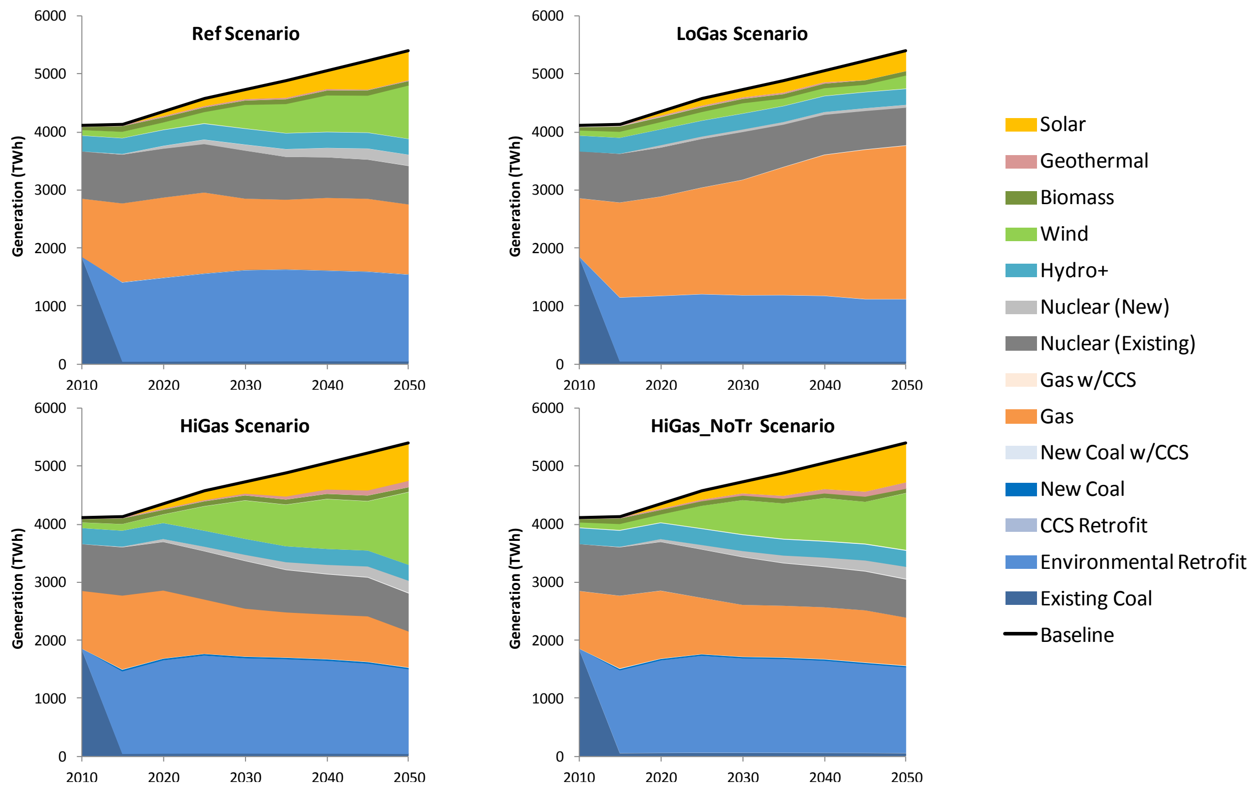

Figure 3
US Electricity Generation 2010-2050 by Generation Technology

Increased Inter-Regional Transmission will be Critical

The analysis generally showed substantially increased inter-regional energy transfers estimated in 2050 for each scenario. Comparison of these values to 2010 values for each scenario shows that in the majority of regions, the imports and exports are significantly (on the order of 2-3 times) higher in 2050 than in 2010 (see Figure 4.) Examination of the regional differences in imports and exports suggests that certain regions will likely be very significant exporters (e.g. Texas, Mountain North, and Mountain South) and others (e.g. Florida, California) will be very significant importers. These results suggest that significantly expanded transmission is likely to be very important in support of a future generation fleet with significantly higher variable generation resources. The need for expanded transmission is confirmed in many other studies, although the feasibility of such an expansion is generally not addressed.

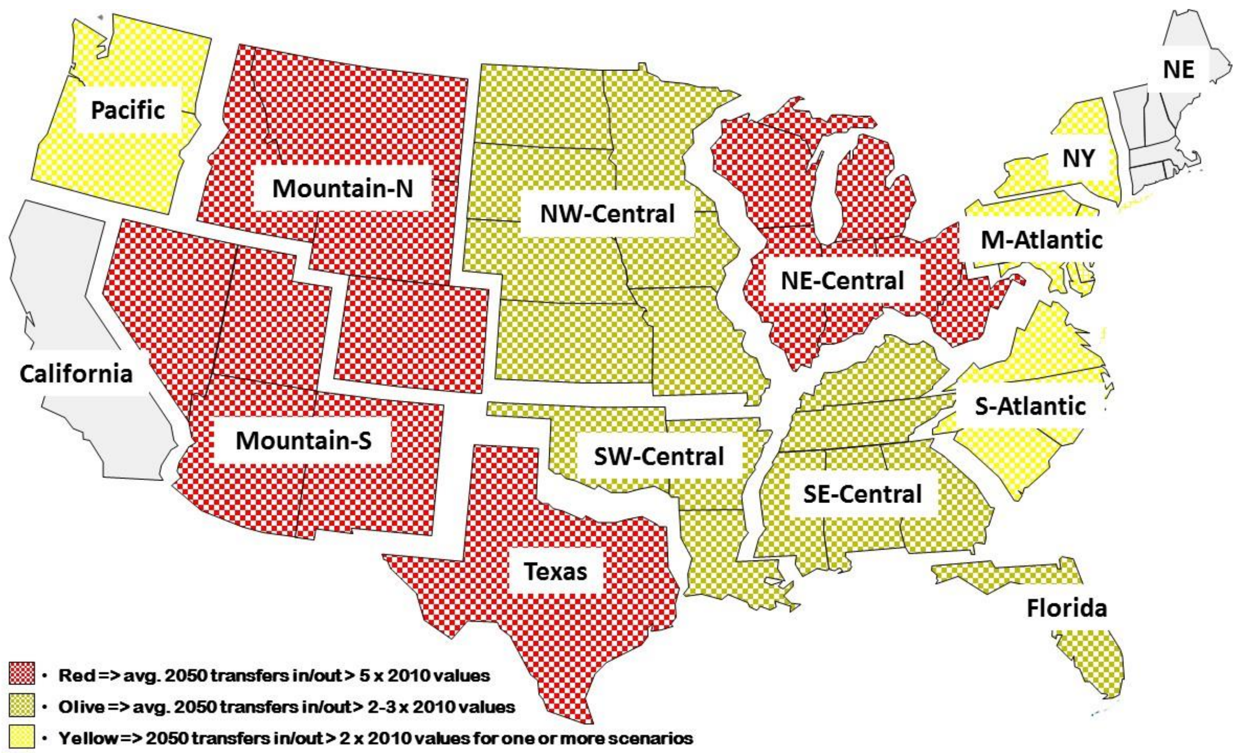

Figure 4
Areas of Significantly Higher Inter-Regional Energy Import/Export in 2050

Dispatchable Generation Assets Will See Much Greater Demand for Flexible Operations

Unit commitment analysis was applied to the generation fleet in each region for selected future years (2025, 2050). This analysis provided a view of the hourly variation in how different generation assets were dispatched. As can be seen from Figures 5 and 6, increased levels of renewable generation in future years lead to significant need for flexibility in coal and natural gas combined cycle operations. These figures also illustrate how demand for inter-regional transfers could increase as a result of over- or under-generation in the region. These results are representative of many other regions.

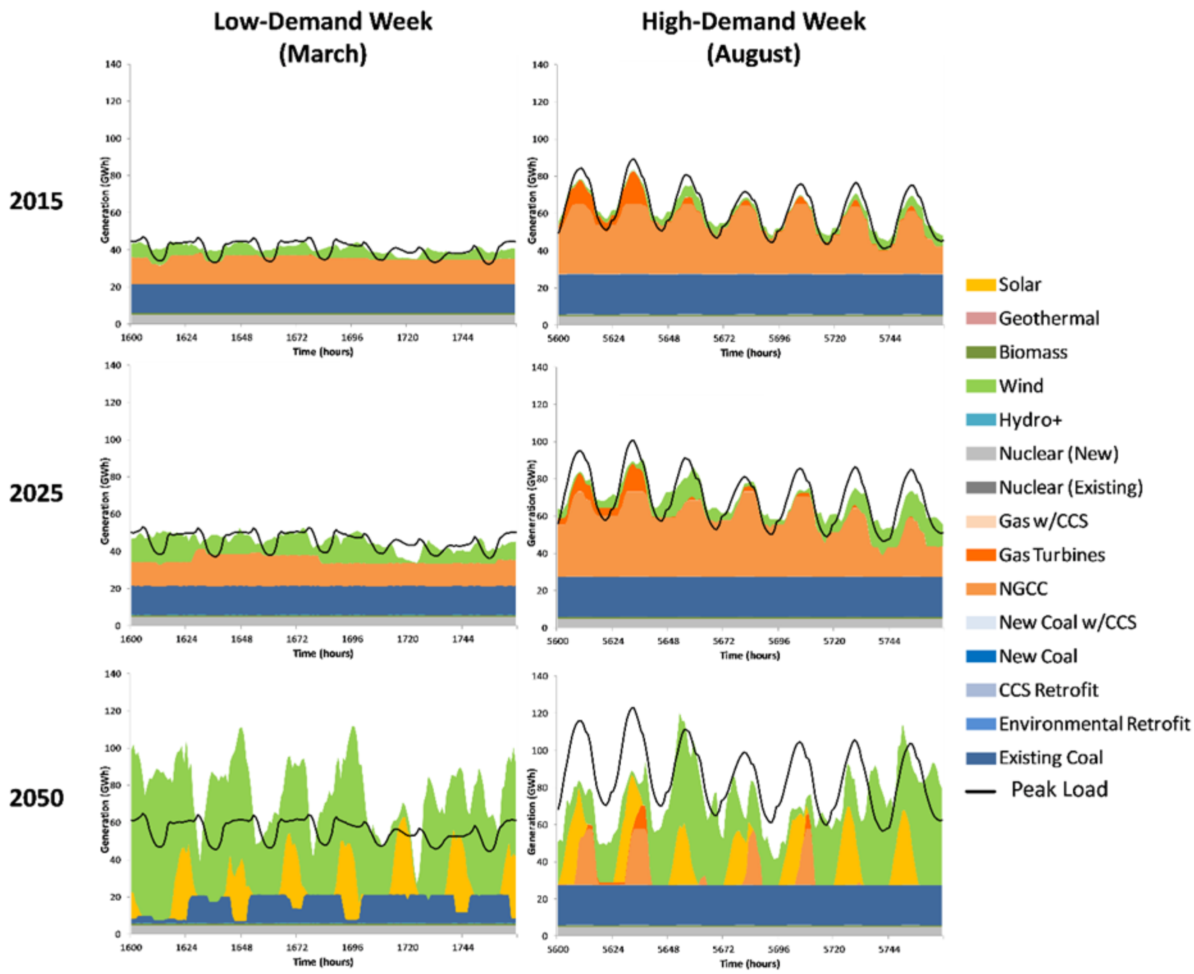

Figure 5
Unit Dispatch in Texas for Low and High Demand Weeks (Reference Scenario)

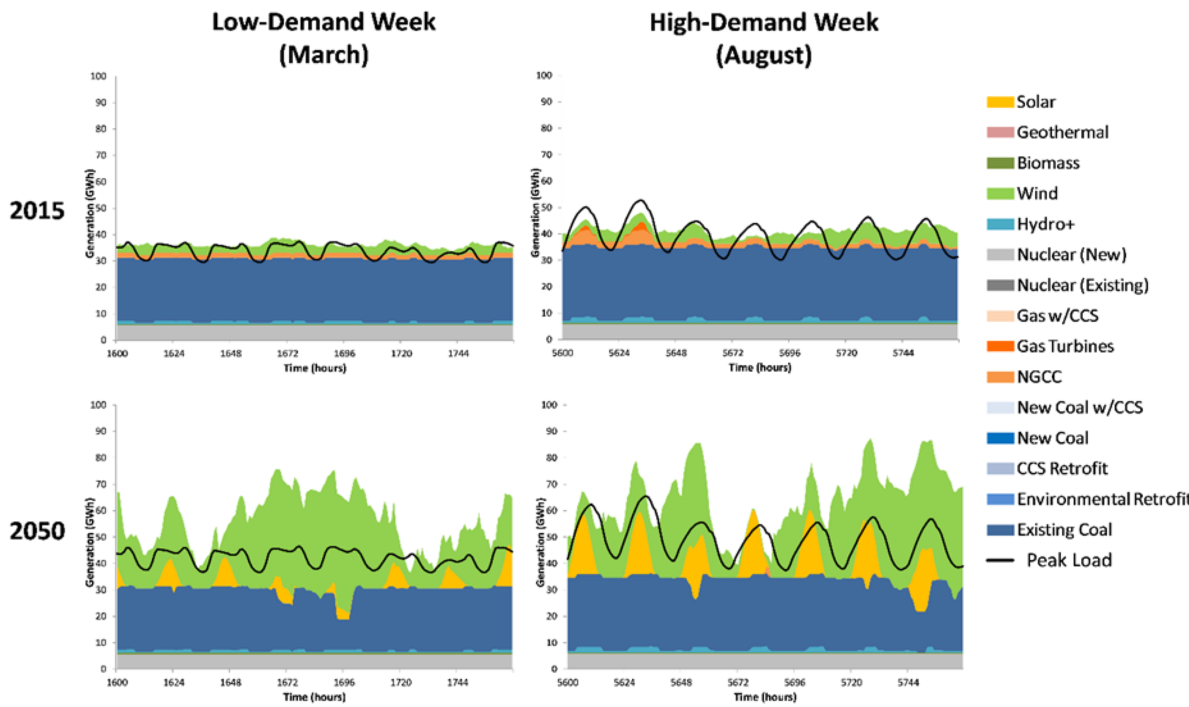

Figure 6
Unit Dispatch in NW Central Region for Low and High Demand Weeks (Reference Scenario)

The underlying data for hourly generation and capacity factor for different generation unit types was analyzed to better understand the trends in the levels of flexible operations indicated in the unit commitment analysis. To achieve this, a generation variability metric was calculated based on the average hourly change in output level for each generation unit over the course of each week of the year. Along with average hourly capacity factor values, these metrics were calculated for each scenario, region and week in 2025 and 2050 to facilitate an engineering assessment of the technical challenges implied by increased flexible operations. The results of these calculations were captured in a series of “heat maps” (an example of which is illustrated in Figure 7.)

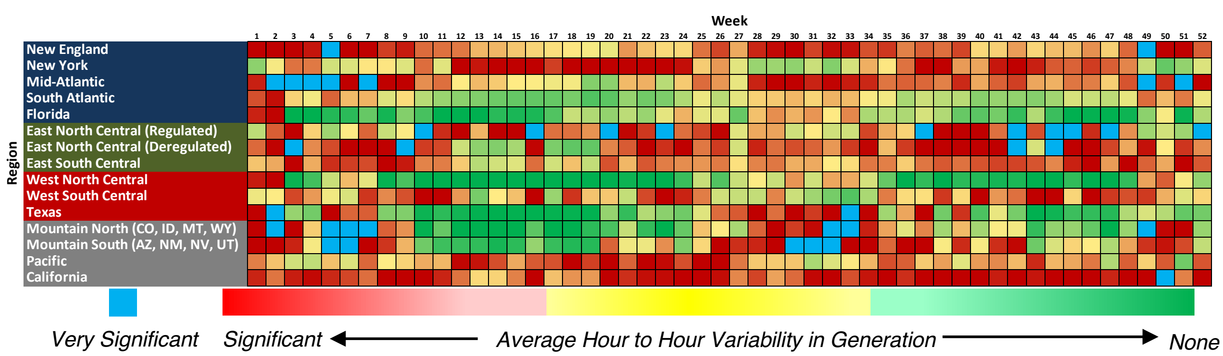

Figure 7
Example Generation Variability Heat Map

A heat map was generated for each generation technology in each scenario for 2025 and 2050. Each cell in a heat map corresponds to a given week of the selected year and a given region. The color represents the degree to which output for generation assets of a given type vary from hour to hour. As the color progresses toward red, this indicates higher levels of hour to hour variability in generation output. Blue represents particularly high levels of variability. This approach allows visual assessment across regions and weeks of the year as well as trending over time, and provides a consistent format for comparison of results for different scenarios. Note that even moderate transition from green to yellow represents potentially significant levels of flexible operations. An assessment of the heat maps across all scenarios for regions which consistently experience high levels of flexible operations for dispatchable assets (principally for natural gas combined cycle and coal units) results in Figure 8. The widespread, significant levels of increased flexible operations are a function of increasing renewable energy generation, the composition of the generation fleet in different regions, and the connectivity of transmission between regions.

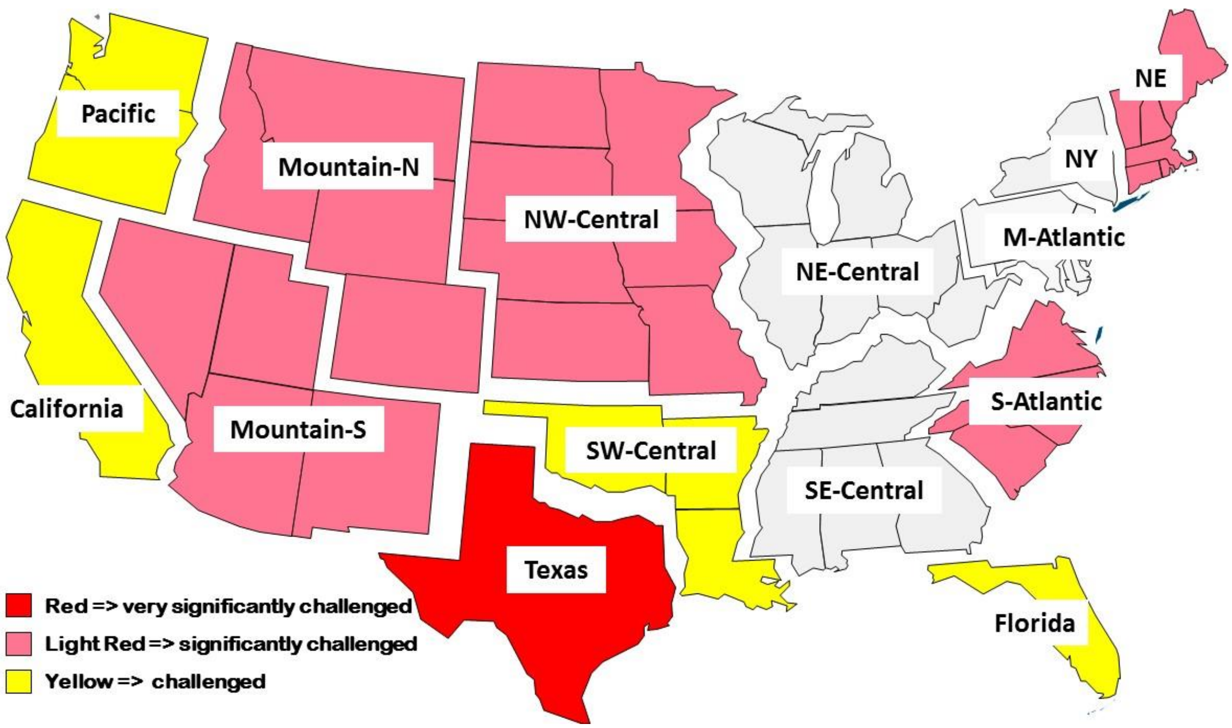

Figure 8
Areas of Increased Flexibility Demand (2050)

Significant Technical and Operational Challenges are Associated with Flexible Operations

A review of the project results was conducted with a group of EPRI subject matter experts (SMEs) with expertise in both coal and gas units relative to several key technical areas affected by flexible operations (e.g. process chemistry, turbo-machinery, gas turbines, boilers, heat recovery steam generators, power plant operations, maintenance, instrumentation & controls). This review resulted in several detailed observations regarding technical issues associated with high levels of flexible operations by coal and gas units. Collectively, the SME comments suggest additional concerns regarding feasibility of very high levels of operational flexibility (although some of these concerns could be mitigated through development of enhanced or new technologies):

- Combustion turbine combined cycle (CTCC) unit lifetimes are uncertain given relatively limited current experience with heat recovery steam generators (HRSGs) and the impact of sustained operations at higher capacity factors,
- Water availability and gas pipeline access may prove to be additional externalities that limit new asset deployment and/or reduce operational flexibility,
- The ranges of CTCC ramp rates in practice today are more limited that what has been assumed in this study,
- Availability of units to operate at low capacity factors or to operate between periods of prolonged layup may in reality be more limited if asset owners opt to retire rather than operate,
- The assumption of existing coal assets being available through 2050 may be questionable from the perspective of the likely need for late-life capital investments that will be necessary to maintain availability and efficiency under increased flexible operations.

Conclusions

This study focused on evaluating the long-term implications of significantly increased levels of variable generation and uncertain natural gas prices on the composition and operability of the future generation fleet in the United States. This goal was achieved by focusing on the degree to which flexible operations are required as the share of renewable energy generation increases. The study adopted a different perspective than typically seen in past studies, i.e. a detailed examination of the engineering feasibility of the level of flexible operations in future generation fleets. The study integrated two key elements of analysis rarely brought together in a single analysis: long-term capacity planning, which enables modeling of unit retirements and new asset investments, and unit commitment analysis, which permits examination of hourly unit dispatch while considering operational limitations relevant to flexible operations capabilities. Four scenarios were evaluated: a reference scenario and three scenarios based on low or high natural gas price trajectories and the potential for future transmission expansion.

Review of nearly 50 studies and papers confirmed that flexible operations are the principal challenge arising from increased variable generation, and that key challenges are operations at minimum loads and significant amounts of ramping at high rates. Many of these studies also confirmed the importance of increasing levels of transmission capacity to enabling fleet-wide flexible operations. However, very few prior studies have focused in depth on the long-term engineering and operational challenges associated with high, sustained levels of flexible operations.

Driven by existing regulatory policies (including renewable portfolio standards), fuel prices, and expected reduced costs for renewable energy, this analysis results in significant levels of renewable (excluding hydro) electricity generation (i.e. 11-41% of total generation) by 2050. Despite variations in the generation technology mix in different regions, widespread high levels of flexible operations are observed across most regions for much of the year by 2050. Frequent, large changes in average hourly generation are observed for combustion turbine combined cycle and coal assets, as well as significant periods of low load operations.

Achieving these levels of flexible operations on such a widespread basis will present several significant technical challenges and is also subject to important external factors that could impede development of fleet flexible operations capabilities. This analysis was based on technical assumptions about operational lifetimes for different asset types and assumes strategic fleet management leading to an economically optimum generation mix. In reality, unit lifetimes for coal and CTCC assets could be significantly shorter based on cumulative damage effects due to sustained flexible operations combined with reluctance by asset owners to invest in units if they are not seen as individually economically viable. External factors such as natural gas prices, potential future limitations on water availability and access to natural gas pipelines could limit how new assets are added to the fleet such that flexible operations capabilities are increased.

In summary, the feasibility of achieving the very high levels of operational flexibility across a majority of the generation fleet as shown in this study is highly uncertain without additional technical capabilities enabling increased flexible operations, expanded inter-regional transmission capacity, and economic drivers causing asset owners to invest in creating increased unit flexibility.

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1
INTRODUCTION

This project was a joint effort between EPRI and the U.S. Department of Energy's Offices of Electricity Delivery and Energy Reliability, Energy Efficiency and Renewable Energy, and Fossil Energy. The objective of this project was to focus on assessing the technical challenges that may arise as much higher levels of renewable energy generation, changing natural gas prices, and other sources of variability as seen by grid-connected central generation stations emerge in the electric power sector.

The project assesses the magnitude of the flexible operations challenge arising for dispatchable assets in the U.S. generation fleet as more and more variable generation is deployed. Note that variability in demand as seen by grid-connected dispatchable generators can also increase due to other factors, such as increased reliance on demand response or customer-driven automation and aggregation of loads.

While the principal area of interest in prior studies has been an evaluation of the feasibility of high levels (i.e. 25-50%) of renewable energy generation share and the necessary conditions permitting those levels, this study is primarily focused on better understanding and projecting the engineering and operational challenges implicit for dispatchable assets (principally coal and natural gas units) in supporting these higher levels.

2
PROJECT GOALS AND OBJECTIVES

The objective of this project was to provide a better understanding of technical challenges and operational impacts of changing fuel costs of coal, natural gas, and of variable renewables on the future mix of electric generation technologies in the U.S. electric power sector, particularly those dispatchable assets whose operations may change significantly in response to the above factors.

In contrast to prior research, this project was developed to inform power companies, researchers, and policymakers regarding the potential engineering, operations, and reliability impacts for dispatchable assets supporting a generation fleet experiencing much higher levels of variable generation and other sources of variability (e.g. increased reliance on demand response, increased levels of distributed generation, and customer load management.) Prior research has typically focused on issues associated with deployment, integration and operations of renewable assets. Frequently, these studies are based on assumptions about operational capabilities of dispatchable generation assets.

This study integrates a comprehensive assessment of the composition of the future generation fleet with industry knowledge and experience regarding the physical effects of this variability (principally increased flexible operations) on generation assets. A better understanding of the long-term impacts of flexible operations demand placed on the power system requires integrating an assessment of how the composition of the generation fleet changes as units retire and investments in new units are made with an evaluation of the impacts of future changes in flexible operations on dispatchable generation assets.

The overall goals were thus to expand and complement industry research on how to best manage generation assets as well as helping to identify key technology R&D priorities that will enable the future generation fleet to have the necessary capabilities to support much higher levels of variability. This project substantially contributes to the goal of providing a secure and reliable energy system that is environmentally and economically sustainable.

3 APPROACH

The project approach consisted of the following tasks; the approach taken for each task is described in this section:

- Review of relevant existing government, industry, and international research.
- Development and analysis of detailed scenarios designed to provide insights into an assessment of operational needs and engineering challenges as the future fleet evolves under market, regulatory, and electricity demand conditions.
- An engineering assessment of degree and scope of technical challenges associated with transformation to the future fleet.

3.1 Literature Review

Substantial study has been devoted to renewables deployment and integration into the power grid. The impacts of flexible operations on generation stations have also been studied by EPRI (e.g. EPRI 2012) and others. Consequently, a literature review of particularly relevant studies, reports, and papers was completed as a precursor to the modeling and analysis forming the core of this study. The literature review was envisioned to provide insights regarding technical assumptions and inputs to the modeling effort. The scope of the literature review was structured to consist of two tasks:

- A review of interconnect and reliability studies, such as relevant NERC studies and regional interconnect studies. An expected outcome of these reviews was a better understanding of operational flexibility requirements that would inform modeling assumptions made later.
- A review of studies focused on existing experience with transformation in the generation fleet, such as impacts of increased flexible operations on costs and unit availability. An expected outcome of these reviews was a better understanding of operational impacts and O&M cost impacts resulting from flexible operations that would inform modeling assumptions made later.

Each review considered the following issues in identifying relevant insights for the modeling and analysis activities in this project.

- Modes of flexible operations
  - How are flexible operations defined (e.g. start/stops, ramp rate, output level, economic reserve, capacity factor, etc.)?
  - How many distinct flexible operations modes are defined, e.g. baseload, load-following/two-shifting, extended minimum load operations, peaking, etc.?

- Costs of flexible operations
  - How are costs of flexible operations represented?
  - Are they assumed to be instantaneous or delayed?
  - How are intangible costs known and accounted for?
  - What elements of costs are considered, e.g. energy costs (i.e. lost generation/lower efficiency, lost availability, replacement power), added maintenance costs, added capital costs?
  - If quantified, what is the magnitude of any added costs, and how do added costs correlate to flexible operations (e.g. output level, number of start/stops)
- Flexible operations dispatch
  - What factors determine when units must operate in a mode other than baseload?
  - How is dispatch of flexibly operating units determined, e.g. market driven or directive based on system operational needs?
- Modeling/analysis approaches
  - How are multiple regions and their transmission interconnection modeled?
  - How are multiple generators of different technology types modeled?
  - How are unit retirements and new asset investments modeled?
  - How is unit dispatch modeled and to what level of time granularity?

The list of studies that were reviewed was developed jointly with the DOE technical advisors overseeing the project and can be found in Appendix B.

3.2 Modeling

3.2.1 Conceptual Approach

This modeling approach uses two traditional tools for power systems analysis, capacity planning (dynamic US-REGEN) and unit commitment (UC US-REGEN), and combines them in a novel way. This is in contrast to other studies where the modeling tradeoff between the degree of operational detail (simulation) and planning detail (optimization) is typically handled by focusing on one problem while treating the other exogenously. In reality, these problems are inextricably linked, as the solution to one has important implications for the other.

UC and dispatch can be thought of as an operations sub-problem of the capacity planning problem, though most capacity planning models ignore operating constraints and adopt a limited number of “representative” segments to model temporal variability. The simplifying assumption in capacity planning formulations with non-sequential hours is that inter-segment dynamics and constraints can be ignored. This assumption only holds in a restrictive domain for systems where generation flexibility matches dynamics of net load, excluding prospective analyses with fleet compositions that differ from current regional portfolios.

Operational flexibility is rarely considered in capacity planning due to the computational complexity of including high-dimensional mixed-integer UC in capacity planning. Many models develop capacity mixes with traditional planning models and then test the resulting mix with production simulation models (e.g. the Western Wind and Solar Integration Study – see summary in Appendix B). The limited research to include UC details in generation planning suggests that their omission may significantly alter the energy production and optimal capacity mix. Palmintier and Webster (Palmintier 2013) suggest that including operational dynamics is especially important in more stringent climate policy environments and when more variable generation is present. Combustion turbines, in particular, seem to be critical providers of flexibility whose value is not captured in models with simplified UC dynamics, which biases capacity and generation values downward in conventional models.

Another embedded assumption in models with limited chronological representation is that correlations between regional loads and variable generation resources can be ignored. This assumption holds only in regions where wind and solar output is small relative to load.

An integrated approach combining UC modeling with long-term, inter-temporal investment decisions enables more effective assessment of the impacts of high levels of flexible operations on near- and long-term generation fleet operations and transformation. This approach allows treatment of fundamental aspects of power plant operations which are most relevant to flexible operations: minimum unit output, ramp rate limits, reduced unit availability, and increased O&M costs. The relationship between variable generation and net load served by dispatchable assets is sensitive on hourly and sub-hourly time scales – this modeling approach permits treatment of the effects of variable generation at an hourly resolution.

In addition to the novelty of the approach, each version of the US-REGEN employs modeling innovations to better capture dynamics of investment and dispatch decisions, as discussed in previous sections. A summary of key characteristics of the dynamic and unit commitment versions of US-REGEN is provided in Table 3-1; these features are discussed in greater detail later in this chapter as well as in the US-REGEN documentation (EPRI 2014, EPRI 2015).

Table 3-1
Key Characteristics of US-REGEN

	Dynamic US-REGEN	Unit Commitment (UC) US-REGEN
Optimization Horizon	Multi-decadal (40 years)	Annual
Temporal Granularity	87 segments per year	8,760 hours
Capacity Mix	Endogenous	Exogenous (from dynamic model run)
Unit Aggregation	100+ capacity blocks per region (dispatched together)	Individual units
Geographical Detail	All user-specified regions	All user-specified regions
Dispatch Constraints	Load balancing	Load balancing, minimum load limits, ramping rates
Optimization Type	Linear program	Mixed integer program

The primary analysis tool for this research is the **U.S. R**egional **E**conomy, **G**reenhouse Gas, and **En**ergy (US-REGEN) model, which was developed by the Energy and Environmental Analysis group at EPRI. This energy-economic model connects a detailed representation of electric-sector investment and dispatch with a dynamic computable general equilibrium model of the economy, though this research uses the electric sector model only,[1] referred to here as "dynamic US-REGEN." US-REGEN offers a snapshot of 15 sub-regions in the contiguous United States and their linkages with each other. The model can be used to investigate a wide range of energy and environmental questions related to technological, economic, and policy-relevant issues in the electric sector and beyond (Blanford, et al., 2014; EPRI 2014).

The US-REGEN suite of models can be run in different modes depending on the research questions and their level of detail. For this analysis, two versions of the model are used:

- **Dynamic:** Solves an inter-temporal capacity planning problem over a multi-decadal time horizon for the electric power sector with aggregated capacity blocks and a simplified representation of dispatch

[1] The dynamic US-REGEN model in this form is known as a "partial-equilibrium" model, since the optimization includes the electric power sector only and does not explicitly model feedbacks with other economic sectors. Among the implications of using the electric-sector-only (dynamic) model is that electricity demand will not change endogenously (e.g., if gas prices are lower than the reference path). Although the dynamic version of US-REGEN is not explicitly modeling other economic sectors (e.g., exogenous industrial demand for electricity is represented but will not change based on fuel market activity), it does preserve regional interactions among power-sector-related firms and trade for these commodities, which includes everything from electricity to renewable energy credits.

- **Unit commitment:** Given the capacity mix suggested by the dynamic model, minimizes total operating costs and determines the startup, shutdown, and operating schedule for every unit during each hour in a selected year

As suggested in Figure 3-1, there is a modeling tradeoff between operational detail (including higher temporal resolution) and computational complexity. Operational flexibility is rarely considered in capacity planning formulations due to the complexity of including high-dimensional mixed-integer unit commitment constraints in large-scale optimization problems. However, capturing these dispatch characteristics is important in understanding flexibility needs, as discussed in Section 3.3.

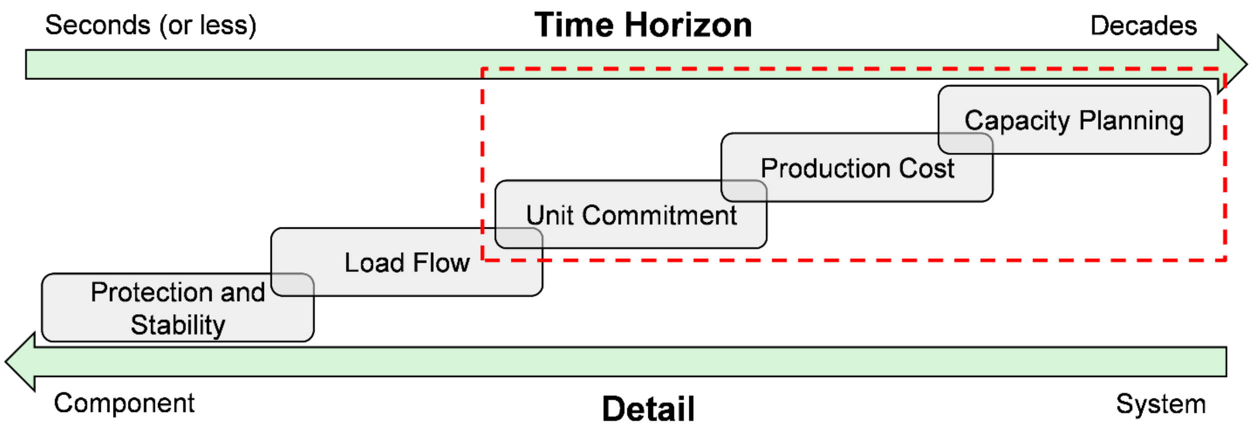


Figure 3-1
Time Scales for Different Types of Power Sector Models

This study uses the dynamic and unit commitment versions of US-REGEN to investigate the degree to which the inclusion of operational constraints may impact the generation mix, especially in settings with increased flexibility needs. To preserve computational tractability while still incorporating cycling impacts and operational detail, these two versions of US-REGEN share data but run separately. The solution of the dynamic model is used as the fleet composition input for the unit commitment model, which can then determine the annual operating schedule for each unit on an hourly basis. Results from the unit commitment model provide data permitting analysis of cycling behavior, which can be used to identify which types of capacity absorb flexibility burdens under different scenarios.

The remainder of this section details the capabilities of the US-REGEN models and describes their uses and linkages for this study. Section 3.2.2 provides a high-level overview of the formulation and data for the dynamic model. Section 3.2.3 summarizes the unit commitment model's structure and compares it with the dynamic model.

3.2.2 US-REGEN Dynamic Model

Dynamic US-REGEN is a regional model of the United States that represents detailed electric sector capacity planning and dispatch decisions simultaneously. Figure 3-2 illustrates the model's default sub-regions, which are aggregations of states. The inter-temporal optimization structure of US-REGEN determines investment and operational choices through 2050 while representing regional resource endowments, costs, demand, and regulations.

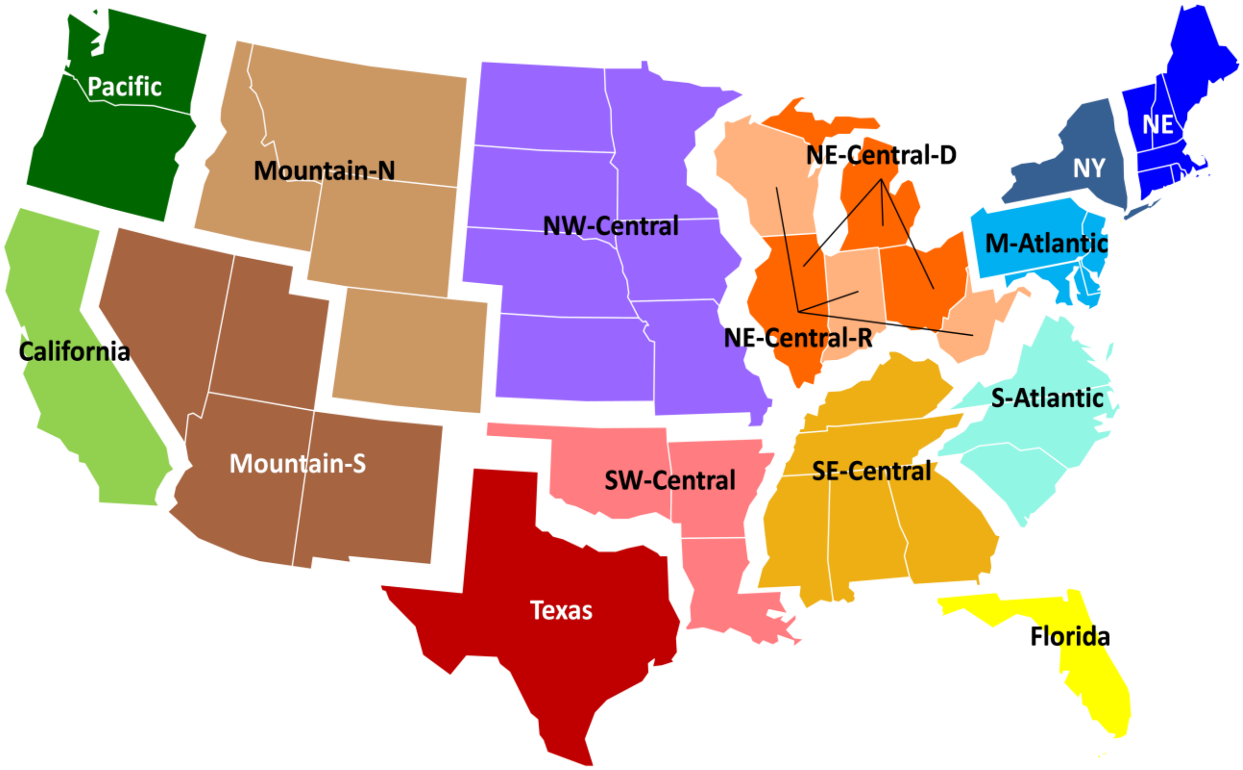


Figure 3-2
Regional Structure of US-REGEN Model

The electric sector module is formulated as a linear process model for this analysis, though it can also represent price-responsive demand. The deterministic framework simultaneously optimizes capacity investments and interregional transmission.[2] The model assumes that agents base their decisions on accurate forecasts for unknown quantities, e.g. natural gas prices and electricity demand are exogenously defined. Variability in regional wind and solar resources is based on historical data, but without any systematic bias (i.e., forecast error is neglected). The bottom-up representation in each five-year time step includes capacity investment, retrofit, and retirement decisions as well as dispatch for installed capacity. Decision variables are indexed by region and by technology types, which aggregate individual units in a region into capacity blocks with similar characteristics. As discussed in the sub-section on "Dispatch and Unit Aggregation" below, these capacity blocks are dispatched for each annual load "segment" (i.e., intra-annual periods representing load and resource availability) without accounting for unit commitment constraints. Bilateral transfer capacity constrains power flows across regions for each segment but can be controlled through transmission capacity investments. The model assumes a five

[2] The costs incurred by producers in the optimization problem include investment costs associated with new generating capacity and inter-regional transmission, variable costs scaled by generation (primarily from fuel and variable operating and maintenance costs), and fixed operating and maintenance costs scaled by installed capacity. Regarding wind and solar, data from 2010 is used only to maintain consistency with other time-series variables (e.g., load, which is also influenced by the same underlying drivers that lead to wind/solar patterns), to avoid averaging approaches that understate/overstate variability, and to capture many decision-relevant features (e.g., periods with multiple weeks of wind of no wind in some regions).

percent discount rate and includes extra model years beyond 2050 to avoid end effects, though these periods are not reported in the results. See Appendix A for additional details.

Data for the dynamic US-REGEN model come from a range of sources. Energy and fuel data are taken from the Energy Information Administration (EIA) of the U.S. Department of Energy. Detailed unit-level data for the existing fleet come from Energy Velocity LLC, which are based on Form EIA-860 data. The model uses cost and performance data from the most recent published and publicly available EPRI reports (EPRI TAG 2009, EPRI RETG 2009), including 2012 updates from the EPRI Integrated Generation Technology Options report (EPRI 2013d).

The fixed O&M values are based on the same EPRI reports and are adjusted by regionalization factors (EPRI TAG 2009) to account for differences across the 15 model regions. Fixed O&M costs include operating labor, maintenance, and overhead charges. Operating labor is calculated based on data for the number of personnel per shift, typical shift data, and the labor rate. Maintenance is determined as a percentage of a plant's initial capital cost, and this percentage is based on the nature of the equipment's operating conditions. Overhead charges are based on estimates of administrative and support labor.

Availability factors for existing capacity are selected to account for average outages through a de-rating process. Most types of units operate at full capacity subject to dispatch for many hours of a typical year but must go offline for scheduled and unscheduled maintenance. However, planned downtime typically coincides with periods of lower demand, which means that flat de-rating modeling of events would underestimate the availability of capacity during peak times. On the other extreme, not accounting for plant outages will overestimate availability, which is especially important for coal capacity. Since no hourly data for unit availability are publically available, the model uses EIA data for monthly generation totals by region. It is assumed that the monthly variability shape that is calibrated to 2010 data remains the same for each period of the model's time horizon. The availability factors implicitly include the base year (2010) reserve margins, since the calibration process does not distinguish between outages and units in reserve. Details of the calibration approach for different capacity types can be found in EPRI documentation for US-REGEN (EPRI 2014).

The dynamic model considers the following generator types when installing new capacity:

- Supercritical Pulverized Coal (SCPC) without Carbon Capture and Storage (CCS) (with full environmental controls)
- Integrated Gasification Combined Cycle Coal (IGCC) without CCS
- Integrated Gasification Combined Cycle Coal (IGCC) with 90% CCS
- Integrated Gasification Combined Cycle Coal (IGCC) with 55% CCS
- Natural Gas Combined Cycle (NGCC) without CCS
- Natural Gas Combined Cycle (NGCC) with 90% CCS
- Natural Gas Combustion Turbine
- Dedicated Biomass
- Nuclear

- Geothermal
- Wind (on-shore)
- Wind (off-shore)
- Solar Photovoltaic (central station
- Solar Photovoltaic (rooftop)
- Concentrating Solar Power (CSP) (solar thermal)

Intermittent Renewable Resources

The spatial and temporal distributions of renewable energy resources and their associated costs are essential considerations in modeling these intermittent and uncertain[3] resources. In particular, models should capture positive and negative correlations between load, renewable resource variability, and uncertainty across adjacent regions given that resources are non-uniformly distributed in space and time. Representing periods of resource extremes is especially important in understanding capacity and generation needs across regions.

These considerations motivated the development of US-REGEN and its regional detail in describing the location of wind and solar resources relative to load centers. The representation of intermittent renewable resources was informed by a collaboration with AWS Truepower to develop hourly data based on 1997–2010 meteorology. In order to preserve synchronicity, correlation, and variance, the output profiles from 2010 are used in the analysis, as these values fall near the center of the distribution while exhibiting considerable variability. Wind output profiles were constructed by aggregating across 5,000 sites (accounting for protected and developed land) into eight onshore and one offshore wind classes based on resource quality, as illustrated in Figure 3-3. A similar screening and aggregation technique was applied to land and resource quality for central-station solar photovoltaic or concentrating solar power.[4] Another dataset was created to estimate rooftop PV potential, and this profile was based on hourly data from 300 cities. The specific technological assumptions underlying these renewable resource profiles are discussed in greater detail in other US-REGEN documentation (Blanford, et al., 2014; EPRI 2014).

Although the time profiles for variable generation and load are critical factors in appropriately evaluating renewable investments, current computational capabilities cannot solve the full intertemporal optimization problem of capacity planning and dispatch for each time period, each region, and each technology with intra-annual representations of all 8,760 hours. In order to retain information about the temporal variability of wind, solar, and load, US-REGEN employs an hour selection algorithm to select representative segments by stressing extremes of their joint distribution. The strategic selection algorithm (discussed in EPRI 2014) reduces the intra-annual shape resolution by two orders of magnitude, using 87 segments to capture the joint temporal variability of renewable resources and load across all 15 model regions. The objective of the

[3] Note that uncertainty is not captured in either the dynamic or unit commitment versions of US-REGEN.

[4] Even after excluding protected, developed, and inadequately sloped land, the solar resource potential is vast. Detailed profiles were developed for the best one percent of available land.

selection process is to maintain key characteristics of the disaggregated temporal data[5] in the reduced form model through these strategically chosen segments. Roughly half of these segments over-sample tails of the distribution (to capture resource extremes), and the other half captures representative behavior across the load, wind, and solar duration curves across regions. Representing the corners of the joint distribution in the selection process recognizes the need to build assets both for bulk energy and capacity needs. Ultimately, weights for the selected hours were assigned to minimize errors across annual totals. This characterization of operational details gives a higher-fidelity examination of tradeoffs among candidate generators under different scenarios, especially when flexibility needs are more salient (e.g., when intermittent generation and more active demand-side management increase variability and uncertainty).

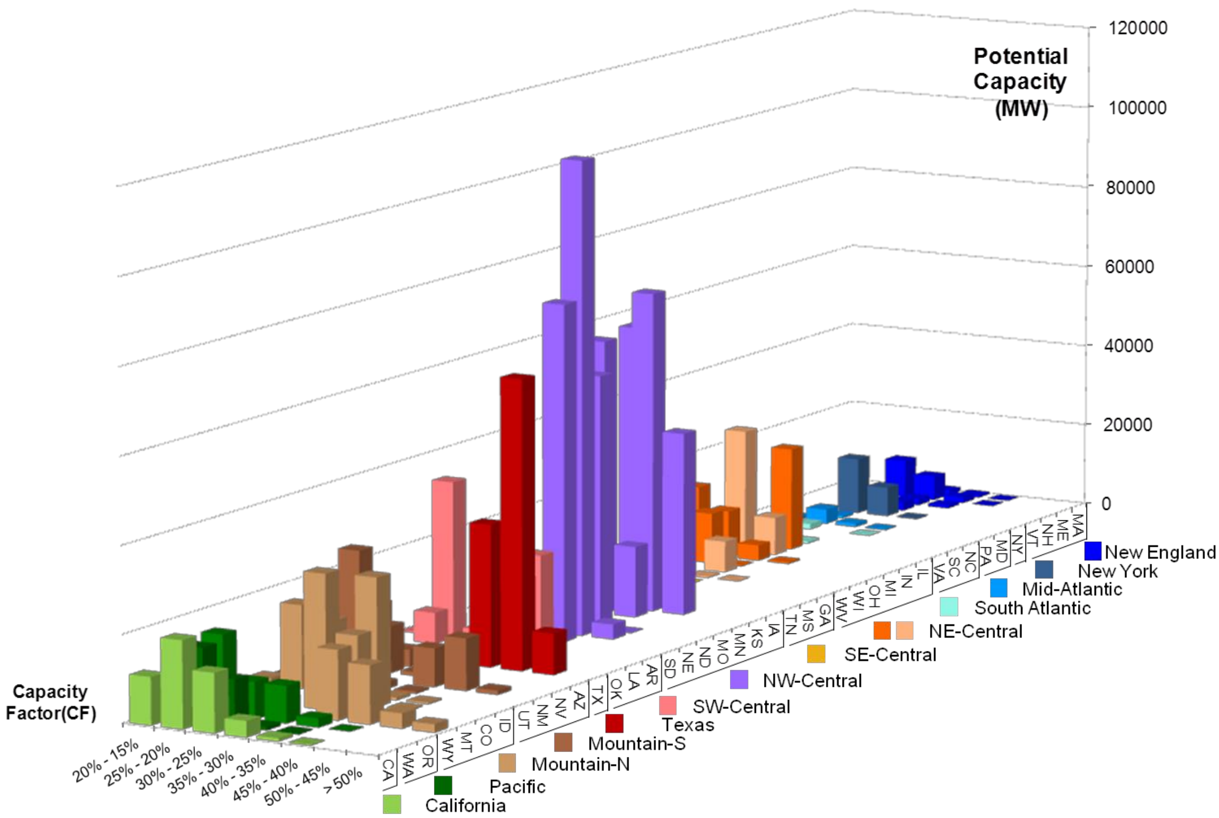


Figure 3-3
Location of Wind Resource by Region and Capacity Factor (EPRI 2014)

[5] Important characteristics include the area under load duration curves for each region (i.e., annual load total), the shapes of these duration curves, the capacity factors of intermittent technologies, and the shapes of these resources relative to load.

Inter-Regional Transmission

Accurately representing inter-region transmission is an important determinant in the valuation of intermittent renewable investments and in understanding how flexibility needs can be met in a given region. (Note that intra-region transmission and distribution are not included in the scope of this study.) The ability to import or export power from or to neighboring regions can provide balancing support during resource surpluses or deficits, marginal cost disparities, and unexpected system events. Such trade dynamics may lower grid integration costs, improve the competitive position of wind and solar, and require less backup than if regions were forced to balances resources with demand independently of each other. The model disaggregation and higher regional granularity of variable generation resource bases (discussed in the previous section) allow identification of higher quality resources, which makes areas potentially more competitive than average resources over a less disaggregated geographical area. Although increasing geographic diversity may mitigate the frequency of operational extremes (Mills and Wiser, 2014), these opportunities can only be exploited through transmission builds that link diverse sites with load centers.[6]

US-REGEN models transmission capacity and flows between (but not within) regions. These inter-regional transfers of power do not explicitly represent a detailed transmission network and do not capture transmission or distribution within the model regions. This “pipeline” approach to transmission models aggregates investments and flows but does not account for network effects or detailed intra-region transmission flow dynamics like many security-constrained unit commitment models do. Data for inter-regional transmission capacity come from the IPM model (EPA 2010) and are mapped to US-REGEN’s sub-regions, as shown in Figure 3-2.

[6] Since wind day-ahead forecast errors tend to be correlated with more concentrated wind sites, greater geographic diversity can increase value of additional wind at higher penetration levels (Mills and Wiser, 2014). However, this impact is not captured in a deterministic model like US-REGEN. The literature suggests that, for many locations and levels of deployment, the largest integration costs for wind/solar come from profile costs (i.e., due to intermittency) rather than from balancing (i.e., due to uncertainty). Hence, US-REGEN’s focus on getting variability “right” rather than in representing uncertainty (which will decrease in time with improved forecasting.)

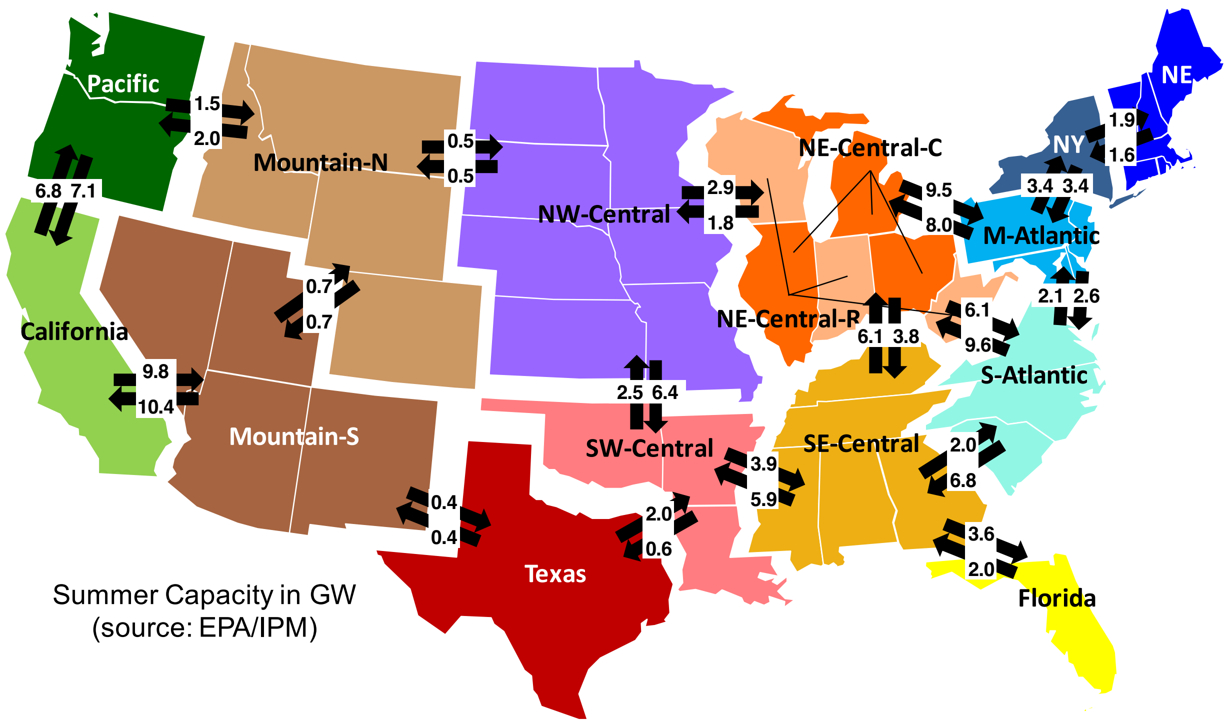


Figure 3-4
Existing Power Transfer Capacity for the 15 US-REGEN Regions (EPRI 2014)

Market-clearing conditions require generation and load plus net exports, including line losses, to balance in each time segment in each region. The complementary slackness optimization condition for trade suggests that, if the marginal unit in Region A has a higher dispatch cost in a given segment than the marginal unit in neighboring Region B (including an adjustment when loss factors are present), then transmission from Region B to Region A would be fully utilized. The transmission system may be an important flexibility asset (as indicated in later results); however, its planning, operation, and organization are complex. US-REGEN's structure does not directly characterize siting challenges or the complete costs associated with building new capacity, but indirectly can capture these effects through prescription of transmission expansion costs. New intermittent capacity incurs a fee of $450 per kW (reflecting hookup and network charges) to incorporate the incremental transmission investment associated with installations. This value is based on discussions with internal and external experts and a review of relevant literature (Mills, et al., 2009; Jaske, 2010).[7] Exogenous assumptions about international (i.e. Canada and Mexico) imports and exports come from the EIA State Energy Data System (EIA, 2010) and are assumed to remain constant over time.

[7] Rooftop solar only incurs a $200 per kW hookup charge, assuming that it is already connected to the grid. Analysis of other scenarios where grid integration costs could be higher is recommended as part of future research.

Dispatch and Unit Aggregation

Existing generators in each region are aggregated into larger capacity blocks based on similar characteristics. The values of performance attributes for these blocks are calculated as the capacity weighted average across units in that respective block. These capacity blocks are dispatched as single units for each segment in a given time period. The temporal resolution for dispatch in the dynamic version of US-REGEN differs from the unit commitment model in that only a select number of representative hours are included in the dynamic model (described above) instead of the complete set of 8,760 inter-annual hours, which is used in the unit commitment model.

It is essential to simultaneously investigate the explicit treatment of dispatch and hourly variation along with capacity investment and retirement decisions. First, the long-lived nature of electric sector assets generates a durable connection between investment and dispatch over time. Second, information about hourly load and resource profiles for non-dispatchable generation resources like wind, solar, and hydro (while dispatchable, hydro has many other non-power related constraints) is needed to appropriately characterize grid operations. The profitability of many asset classes depends on the inclusion of such characteristics. For instance, neglecting flexibility needs may undervalue fast-ramping combustion turbines (Palmintier and Webster, 2013). Third, resource utilization depends on the installed fleet mix across a balancing region and the potential for bilateral trade with adjacent regions. Inter-regional transmission can allow available assets in neighboring regions to be exploited to serve flexibility needs, which makes representation of trade (and consequently hourly variations in demand and supply) critical.

When price-responsive demand is restricted, the model minimizes cost subject to the constraint of meeting reference demand in each inter-annual segment. For the optimality conditions to describe a competitive equilibrium outcome, capacity blocks are dispatched in each region in increasing order of marginal costs for a given segment (excluding unit-commitment-related costs). This market-clearing requirement simulates the clearance of both energy and capacity markets, as illustrated in Figure 3-4. In the model's deterministic structure, constraining electricity generation to equal load in each segment represents the implicit stipulation that sufficient reserve and capacity investments occur to balance supply and demand in the peak segments. Thus, the US-REGEN analysis for this study does not explicitly incorporate ancillary markets (e.g., spinning reserve, capacity markets).[8] The optimization algorithm is designed to ensure that sufficient reserves and capacity are built to cover any event occurring within the model's time horizon; thus, for the base case scenario, US-REGEN does not explicitly incorporate any auxiliary markets, such as spinning reserve or capacity markets. Note that the calculation of availability factors for generation implicitly includes whatever reserve margins were in effect in the calibration year (2010). Importantly, the requirement that demand is met in every segment simulates the clearance of both an energy market and a capacity market. That is, by requiring that sufficient electricity be produced in each segment to meet the prescribed load, this constraint also stipulates indirectly that sufficient investment in capacity occur such that electricity for the prescribed load in the "peak segment" will be available for dispatch. As will be discussed in more detail below, this stipulation applies even with large deployment of variable

[8] Note that although US-REGEN has the ability to incorporate spinning reserve or reliability (i.e., non-spinning) reserve constraints for applicable scenarios, they were not modeled as part of this study due to significantly increased computation times. Prior studies suggest that this decision isn't likely to significantly alter results.

renewable capacity which is known to have low coincidence with peak demand, such as wind. In scenarios where intermittent renewable capacity comprises larger fractions of generation, the model endogenously builds additional balancing assets like surplus dispatchable capacity (i.e., the total nameplate capacity for many regions greatly exceeds peak generation needs).

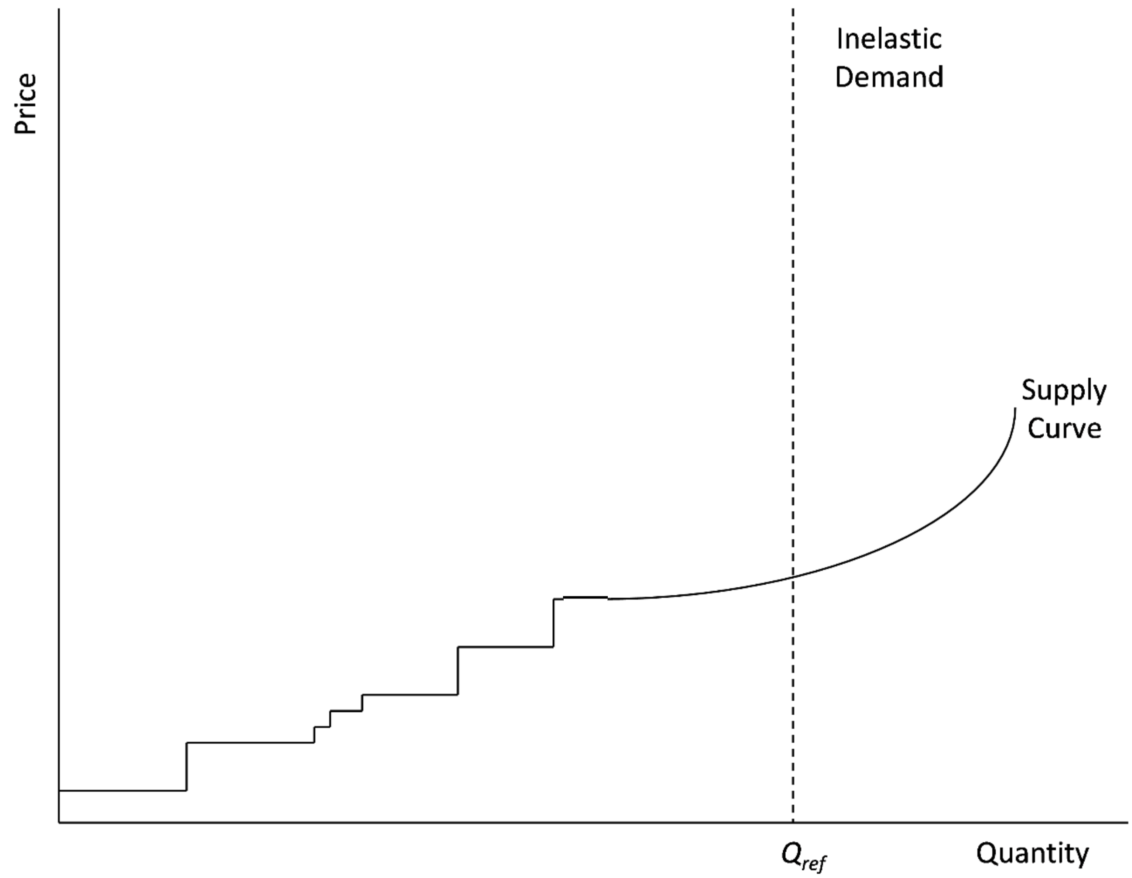


Figure 3-5
Objective Function for Electric Sector Model with Inelastic Demand (EPRI 2014)

Key General Assumptions and Model Characteristics

US-REGEN and similar energy-economic models must make a range of assumptions in formulating and characterizing the US power system and its relation to other economic sectors.

- **Perfect foresight:** The inter-temporal optimization formulation of US-REGEN implicitly assumes perfect information of forward-looking agents across the multi-decadal time horizon. The deterministic framework simultaneously optimizes capacity investments and interregional transmission. The model assumes that agents base their decisions on accurate forecasts for unknown quantities, e.g. natural gas prices and electricity demand are exogenously defined. Variability in regional wind and solar resources is based on historical data, but without any systematic bias (i.e., forecast error is neglected). For example, the model "knows" future natural gas prices with certainty when making capacity investments and can predict variations in wind and load without uncertainty when making dispatch choices. Although this formulation precludes hedging behavior, it can address least-cost portfolio decisions subject to scenario-specific technological, economic, and policy-related assumptions relative to a reference scenario.

- **Electricity demand growth:** The benchmark equilibrium for US-REGEN is calibrated to exogenously specified projections from the most recent Annual Energy Outlook from the EIA. This exogenous growth assumption in the electric sector model, along with demand in other economic sectors in the integrated model, can be modified or allowed to endogenously respond to price changes to evaluate the sensitivity of results to alternative scenario assumptions. However, this analysis assumes that price changes in the scenarios considered here will not cause consumer demand to deviate from the reference growth path (i.e., assuming a zero price elasticity of demand).
- **Fuel prices:** Like electricity demand, the prices for fuels like coal, natural gas, and petroleum are based on the most recent AEO projections (EIA 2014). Natural gas price scenarios have varied tremendously in recent years, which is why scenarios in this analysis explore alternative sensitivity cases with lower and higher values to understand the implications of this fuel-price uncertainty.
- **Infrastructure representation:** The representation of transmission expansion and flows offer aggregate pictures of electricity transfers across regions out of computational necessity, which results in not explicitly considering many other transmission constraints. Regional natural gas infrastructure is currently not represented in US-REGEN (either in terms of constraints on existing capacity or of new additions), though efforts are underway to include such dynamics in future versions of the model.
- **Curtailment and energy storage:** Energy storage is not represented, but intermittent renewable technologies can be curtailed during periods of overgeneration.

3.2.3 Unit Commitment Model

Although there is uncertainty about when and how much new variable generation capacity will appear on grid, there is a great deal of interest in understanding potential impacts of this deployment on the existing fleet of generators. Accurately quantifying the environmental and economic changes induced by intermittent renewable deployment requires detailed modeling of the interconnected power system. Many reports indicate that integrating large amounts of variable generation onto the grid is technically feasible (e.g., IPCC, 2011); however, there are many engineering and economic challenges that could play a decisive role in the actual amount of deployment.

The unit commitment (UC) version of US-REGEN addresses the important role of dispatch, temporal variability, and operational constraints in determining the flexibility needs and economic value of assets. The appropriate representation of short-term decisions related to power system operations requires treatment of system constraints, which are not traditionally captured in reduced-form representations of dispatch (especially in multi-decadal capacity planning). Capturing these characteristics is critical to understanding the potential long-run impacts and economic implications for the future generation fleet.

Given the importance of transmission and trade in influencing electricity market outcomes, a novel feature of the US-REGEN UC model is its endogenous treatment of imports and exports. Trade may function as a flexibility resource to facilitate the exchange of electricity across regions during periods of surpluses or deficits, especially as intermittent resources comprise a greater fraction of generation and regional electricity markets become more tightly integrated. However, most UC models make simplifying assumptions about imports and exports, often assuming that future trade flows will mimic historical patterns. US-REGEN's integrated perspective models many regions at once to capture the increasingly interconnected landscape for system balancing. This formulation endogenously determines price-responsive imports and exports to and from adjacent regional markets.

Production Cost Models

Production cost models are typically used to determine the cost of operating a particular power system with fixed capacity. Given this general definition, UC models like US-REGEN can be viewed as deterministic production cost models that determine which resources to use given a set of system constraints. The problem of allocating demand across a fixed stock of available generators entails minimizing cost while simultaneously satisfying a variety of operational constraints. The UC version of US-REGEN is a deterministic hourly chronological UC and economic dispatch simulation. Other models (e.g., PLEXOS) can have subhourly detail, power flows, or represent uncertainty (e.g., in security-constrained UC frameworks) for reliability modeling.

Using a UC approach for modeling system flexibility and cycling impacts has many advantages. First, UC approaches contain the unit-level detail needed to simulate the large-scale dynamic dispatch problem faced by system operators and complex, inter-temporal generator costs. Simplified methods that approximate commitment and dispatch decisions are not able to adequately represent unit operations, which frequently involve more complex tradeoffs due factors such as ramping constraints, partial-load performance characteristics, and startup/shutdown costs. The implications of these issues on generation fleet transformation while maintaining economic competitiveness is currently not well understood. Second, UC models can examine prospective scenarios with fleet compositions that are markedly different from present systems, as is done in this project with the coupled use of the dynamic and UC versions of US-REGEN. Despite these benefits, the combined use of UC models with inter-temporal capacity planning models have received limited application in this research domain due to their computational complexity and resource-intensive nature of their implementation. To overcome these challenges, the UC variant of US-REGEN employs a novel formulation of the traditional UC problem, as described in subsequent sections. Finally, the high temporal resolution embedded in the UC approach can capture the operational detail of systems with intermittent resources and characterize their economics with greater fidelity than most generation planning models. The intermittency of wind is especially problematic in the US context, where the inconvenient time profiles for wind mean that resources are negatively correlated with load. This co-variation is an important driving factor in the decreasing returns to scale of intermittent resources (i.e., the marginal economic value of additional variable generation declines for higher penetration), especially in the presence of costly storage and absence of real-time pricing (Mills and Wiser, 2012). Modeling integrated system operations at a UC level is also important given the physical limitations on renewable resource bases and their spatial and temporal dispersions. These factors require transmission to connect these resources with load centers and to increase trade as a balancing strategy, which introduces additional integration and connectivity constraints. Properly accounting for the role of transmission must incorporate engineering and economic linkages across regions, which can depend upon chronological features and commitment histories in UC models.

Additional detail about the UC model can be found in EPRI 2015.

Formulation

The unit commitment and economic dispatch US-REGEN model determines the startup, shutdown, and operating schedule (including unit-specific output levels) for every unit during each hour of an annual time horizon. The model takes the perspective of a grid operator that minimizes total operating costs while meeting electricity demand and satisfying other system constraints. The model represents an energy-only wholesale electricity market where an operator uses a UC algorithm to select generation based on bids from market participants and on perfect forecasts of electricity demand and renewable resources.

Combining economic dispatch with UC constraints results in a mixed-integer optimization problem with the objective of minimizing operating costs for all units across the annual time horizon. The four primary constituents of total operating costs are variable O&M costs, fuel costs (with output dependent heat rates), startup costs, and shutdown costs. The UC model contains constraints like a load balance (market-clearing) condition, maximum and minimum output levels for each unit, optional operating reserve requirements, startup and shutdown logic for generators, minimum up and down times, and maximum ramp rates for units.

The primary decision variables in the model indicate the schedule of commitment, startup, and shutdown for each unit in each period. These binary UC variables prevent units from operating in the infeasible region (i.e., dispatched below the minimum feasible load) and give rise to the mixed-integer formulation of the UC optimization problem.

Fuel use characteristics and emissions are impacted by operating at outputs lower than their maximum rated levels, which leads to a reduction in unit efficiency (i.e., increase in a unit's heat rate). The general relationship between unit output level and heat rate at the fleet level is somewhat difficult to determine. EPRI (2011) was used to quantify the effects of load following on heat rate. US-REGEN adopts the functional form based on this work and selects the heat rate penalties at minimum output for different capacity types based on consultations with literature and EPRI researchers.

The UC model currently reports the wholesale price of electricity for each hour (i.e., time segment) in each region. This marginal price corresponds to the dual variable associated with the load-balance constraint, which enforces balancing between generation and load plus net exports (including line losses). The shadow price of this market-clearing constraint at optimality equals the change in the objective function value if the binding load constraint could be relaxed by one unit (i.e., the marginal cost of producing an additional unit of electricity at a given time). Transactions across regions are driven by cost differentials that make it more economical to purchase electricity from neighboring areas (after accounting for trading costs) than to generate within the region owing to heterogeneity in supply- and demand-side conditions. Since market power is not represented, differences in the wholesale market-cleaning prices across regions in equilibrium typically arise when transmission constraints are binding and prices cannot be equalized across regional markets. Transmission resource scarcities are more common in periods when excess generation from intermittent resources cannot be exported to other regions and must be spilled. Curtailment is available for wind and solar and is assumed to be costless.

Unlike the dynamic US-REGEN model where similar units in a region are aggregated to facilitate computation, the UC model retains individual unit detail for a majority of the fleet in the region of interest. Decision variables related to operation are indexed over the set of all units in the US-REGEN region greater than 40 MW. Units smaller than this threshold operate in accordance with historical dispatch. Since intra-regional transmission is not modeled, variable generation resources across a model region are aggregated by their capacity types and dispatched as blocks. Wind and solar technologies can be curtailed during periods of overgeneration.

The upstream code for the UC model harmonizes data with the dynamic version of US-REGEN. However, transferring results of dynamic runs requires a few simplifying assumptions to downscale aggregate capacity block retirements and additions (which are decision variables for the dynamic model) into individual units. For each capacity type in each region, new units are added with average sizes of new units suggested by the NEMS Electricity Market Module (EIA, 2013) until the total capacity in the UC model equals the value suggested by the dynamic model. Retirements also loop over each capacity block in each region and remove units until the capacity in the two US-REGEN models converge. The model follows the decision rule of retiring the oldest units of a particular capacity type first.[9]

The actual peak load in some regions may not be captured in the representative hours used in the dynamic model. This gap occurs as a result of the hour selection process for the simplified load curve used in dynamic US-REGEN, which stresses the maximum load relative to variable generation output instead of the maximum itself (EPRI 2014). To account for this discrepancy, the peak demand hours for the eastern and west interconnects were added to the extreme-spanning and clustering hours; however, these two hours may not capture the true peak in each region. The UC version of US-REGEN also gives the option to allow capacity rentals in a given region. Capacity rentals in the UC model ensure that there is enough capacity to supply electricity to satisfy demand during peak hours and to prevent capacity shortfalls (in regions where the dynamic model does not build quite enough capacity to cover the year's maximum load hour). For the modeling in this project, the only type of capacity that can be rented is a combustion turbine. Results across a range of scenarios suggest that this rental option is used sparingly and is deployed primarily due to the discrepancy between the true peak hour in a region and the highest load hour in the dynamic model. Thus, during a small fraction of hours in some regions, wholesale electricity prices will be at least an order of magnitude higher than the dispatch cost, which means that the average annual price reflects the complete long-run marginal cost of supply.

A novel feature of the US-REGEN UC model is its treatment of imports and exports. Trade may be an important flexibility resource to facilitate the exchange of electricity across regions during periods of surpluses or deficits. However, many existing UC models make simplifying assumptions about imports and exports, often assuming that future flows will match historical values US-REGEN's integrated perspective models many regions at once to capture the increasingly interconnected landscape for system balancing. Transmission capacity investments are made in the dynamic model and transferred to the UC model.

To make the UC model of the entire US computationally tractable, US-REGEN has individual unit detail in the region of interest but aggregates units into capacity blocks (with the same identifying characteristics as the dynamic model) for all other regions.[10] This formulation allows price-responsive imports and exports to and from adjacent regional markets and can determine location-specific market-clearing prices. The bilateral flows assume that traded electricity is a homogenous good and that trade is constrained by transmissions across (but not within) regions. Constraints in the UC model ensure that the power flows are consistent across regions on an hourly basis and are subject to trade-volume constraints (i.e., do not violate physical transmission

[9] If retiring the oldest unit in the UC dataset would exceed the dynamic model retirements, then the UC model lowers the capacity of the oldest unit online.

[10] Economic decisions in other regions do not account for unit-commitment-related costs (e.g., costs associated with rapid ramping or startup), which means that model results likely understate engineering and economic challenges associated with flexible system operations in other regions.

constraints in the balancing area). The shadow price on the transmission-volume constraint equals the price differential between the trading regions less transmission charges.

The combinatorial expansion of potential commitment states make the UC problem a computationally challenging one, especially as the number of generators and length of the horizon increase. These difficulties are important to overcome for annual UC runs, as load and renewables have seasonal variations that make year-long runs critical. US-REGEN overcomes these challenges and accelerates UC computation to enable annual runs by employing a rolling commitment horizon solving approach. This strategy links shorter optimization horizons (e.g., twelve one-month periods instead of an entire year) by rolling forward in specified increments with sufficient overlap to avoid beginning and end effects. Figure 3-3 illustrates this partitioned horizon approach with overlapping periods.

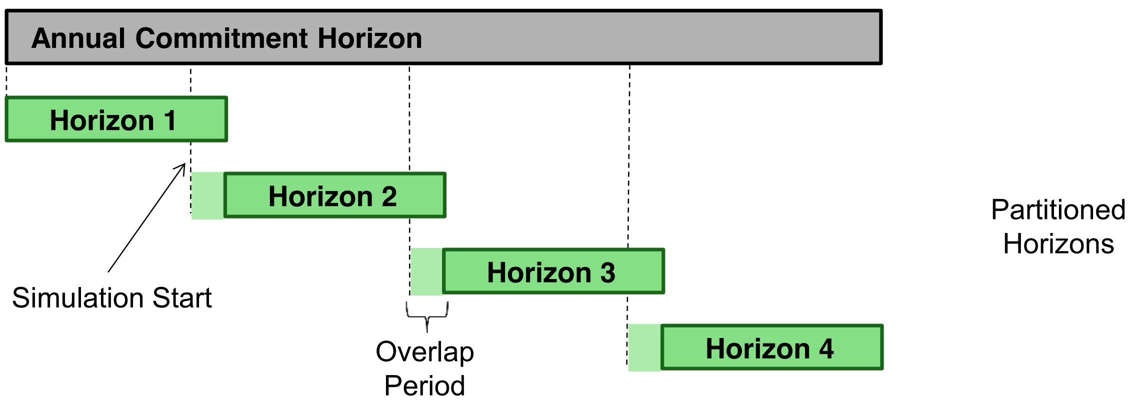


Figure 3-6
Diagram of Rolling Commitment Horizon Solving Approach

Data

Data were obtained for each existing generating unit in the US from the Energy Velocity database that is used and aggregated for the dynamic US-REGEN model. Many values are expressed on unit-specific basis like minimum[11] and maximum capacities, ramp-up and ramp-down limits, and fully-loaded heat rates. Other parameters take on capacity-block-specific values from their corresponding dynamic US-REGEN classes, including fuel prices (which vary by region), variable O&M costs, and availability factors for each segment. Other parameters are specified on a fuel-specific basis such as startup and shutdown costs, minimum up and down times, and the assumed heat rate penalty at minimum output levels. Unit-specific values are based on Form EIA-860 (Annual Electric Generator Report).

The dataset of hourly wind and solar output by resource class and state are identical to the dynamic US-REGEN values described in the section above on intermittent resources. Synchronous historical hourly load data at the state level were derived from FERC Form 714 (Part III Schedule 2) reporting at the NERC region level, which are based on observed data from 2010. Hourly shapes are scaled to match electricity consumption as reported by the EIA for each state. The shape of wholesale power demand for each inter-annual hour in each region is

[11] Note that the minimum load as a percentage of the maximum capacity is determined at a capacity-block level.

assumed to be static over time but is scaled by the exogenous trajectory of demand growth used in the dynamic model (based on the Annual Energy Outlook reference case). This hourly temporal granularity is important in characterizing emissions behavior due to the intraday nature of variable generation and its interaction with load.

Understanding US-REGEN through Model Comparison

Given how different models are better suited to answer different questions, it is critical to understand the comparative strengths and shortcomings of US-REGEN relative to other generation planning and unit commitment models.

The Electric Generation Expansion Analysis System (EGEAS) model is used by many utilities and regional planning organizations for generation planning and production costing. The model determines the least-cost resource planning forecast to meet a planning reserve. It minimizes the present value of reserve requirements while adhering to constraints of reliability (e.g., reserve margin, unmet energy, loss-of-load probability) and tunneling (i.e., specifying upper and lower bound constraints for resource investments and use). EGEAS is used to reduce the number of scenarios for further analysis using more complex production costing models like PROMOD and PLEXOS, which allows the model to perform probabilistic production costing for reliability analysis. The model solves generation and transmission planning in two distinct steps, which means that generation and transmission planning are not simultaneously co-optimized like dynamic US-REGEN. EGEAS also does not model unit commitment constraints (e.g., startup costs, minimum down times, ramp rate, minimum output levels, indivisibility of units) like the UC version of US-REGEN. The dispatch capabilities in EGEAS use monthly duration curves, which do not capture chronological simulation like US-REGEN is capable of doing. EGEAS is typically used for single-region analysis, which means that it does not examine all control area and optimized dispatch (and the economic implications of these operating decisions) simultaneously like US-REGEN.

PROMOD is a production costing model with hourly dispatch. It enables users to perform detailed generator portfolio modeling and forecasting of locational marginal prices. Although the hourly temporal resolution is similar to the UC version of US-REGEN, PROMOD has much more detail about generators, buses, branches, monitored lines, and contingencies in its representation of commitment and dispatch (including detailed transmission constraints allowing for more detailed line flow analysis). However, unlike the dynamic version of US-REGEN, PROMOD does not allow for sequential optimization through optimizing generation planning and transmission expansion over long time horizons. Like EGEAS, PROMOD normally runs single region analyses, which makes it difficult to capture interactions across regions (e.g., bilateral trade flows) as in US-REGEN. A significant practical limitation for PROMOD is significant computational demands - an annual run (with 8,760 hours) can take between 60 and 90 hours to run (unlike the UC version of US-REGEN, which typically takes 1 to 3 hours). This hampers designing multiple analyses for asking “what-if” questions.

PLEXOS is another prominent production costing model that uses a mixed-integer programming formulation to solve short-, medium-, or long-term unit commitment problems. Unlike the aforementioned models, PLEXOS offers a range of planning horizons from short term (e.g., minutes or hours) to long term (e.g., from one to four decades). Like US-REGEN, PLEXOS can co-optimize capacity and transmission planning. Unlike US-REGEN, PLEXOS is capable of performing power flow assessments. Like EGEAS and PROMOD, PLEXOS includes the typical state- or region-level boundaries and comparatively long run times.

Caveats

The UC version of US-REGEN (EPRI 2015) and the scenarios in subsequent sections make a range of assumptions in formulating and characterizing the power system dispatch.

- **No large-scale storage:** The runs for this analysis do not include the possibility of large-scale storage, though existing pumped hydro storage is represented.
- **Deterministic structure:** The perfect foresight framework of the UC version of the US-REGEN model means that some dynamics of system operations and values of certain assets may not be appropriately captured. For instance, studies have suggested that real-time pricing may be able to alleviate unforeseen forecast errors (in wind and demand) by responding to events quickly and provide a substitute for fast-ramping capabilities (Mills and Wiser, 2014). The UC model cannot capture the value associated with mitigating these deviations from day-ahead forecasts.
- **Exogenous demand:** Although demand-side management could potentially play an important balancing role, price-responsive demand is not incorporated in the UC model.
- **Hourly temporal resolution:** The temporal structure of the model omits impacts of subhourly variability and its associated operational difficulties. Again, these exclusions mean that US-REGEN is not a suitable testbed for answering detailed questions about ancillary services, storage, or forecast error when subhourly detail is critical.
- **Unit-level data for the region of interest only:** Although the UC model captures unit-level detail in a specified region for a given run, it aggregates units into capacity blocks for adjacent regions, which means that UC-related unit constraints are not applicable outside of the region of interest. This formulation allows price-responsive imports and exports to and from adjacent regional markets (unlike most other UC models, which treat these dynamics exogenously) but overstates the provision of flexibility from other regions and their ability to adjust dispatch rapidly.
- **Rolling commitment horizon:** Although the partitioned horizon approach enables year-long runs, not having one-shot annual runs makes interpretation of capacity rental challenging, difficult to enforce compliance for policies with annual requirements, and introduces potential fidelity issues with actual commitment decisions.

Note that, although the UC model will find feasible solutions for dispatching available resources to meet load constraints in all scenarios, such solutions may not necessarily be feasible in practice given the caveats in this section. The pattern of dispatch configurations, if actually implemented, might in reality require processes and resources that are not included in the model due to computational tractability considerations. Additionally, the expansion of the technology options for balancing technologies (e.g., large-scale storage or more flexible dispatchable generators) can alter feasibility and lower operating costs. The above observations are part of the reason for the engineering analysis of modeling results included in this report.

3.3 Analysis Plan

The analysis investigates the importance of key unknowns by using the dynamic and UC versions of US-REGEN to understand how exogenous technological, economic, and regulatory uncertainties will influence the need for flexible operations. The four dynamic scenarios discussed below explore the impact of natural gas price trajectories and inter-regional transmission constraints.

3.3.1 Reference Case Assumptions

This section discusses the key reference assumptions related to technology, economics, and policy in the dynamic US-REGEN model. The reference case is not a forecast of the future but a counterfactual starting point for "what-if" comparisons across scenarios holding all other factors constant. It is especially important to understand the baseline assumptions and their influence on the results as a basis for insight with treatment cases. It is important to keep in mind that models like US-REGEN[12] "may contain approximation errors, insufficient system dynamics, and incomplete data representations" (EPRI 2014). However, comparison of results from different scenarios is informative regarding key trends and drivers of unit deployment.

Energy Demand and Transmission

The dynamic electric sector version of US-REGEN uses data from the EIA's 2014 Annual Energy Outlook (EIA, 2014). The model adopts AEO 2014 values for the projected level of energy demand over time and reference energy prices. The reference scenario permits transmission expansion at a cost of $3.85 million per mile of a national high-voltage line. The limited new transmission scenario reflects challenges associated with public acceptance, siting, or other region-specific factors that may be difficult to capture given the model's structure by prohibiting addition of new inter-region transmission.

There are two varieties of transmission constraints in the dynamic model. First, national build constraints place an upper bound on capacity additions relative to 2010 levels and are based on historical build rates. The assumptions on decadal build limits are assumed to increase over time based on improved regulatory conditions, as shown in Table 3-2. Second, regional transmission constraints place an absolute upper bound between any two adjacent regions equal to 2 GW by 2020, 4 GW by 2025, 8 GW by 2030, 16 GW by 2035, and unlimited in later periods (but still subject to the national build limits in relative terms).

[12] Other prominent energy models with similar structures and applications like US-REGEN include the US-REP model developed by the Massachusetts Institute of Technology, the ADAGE model used by the Environmental Protection Agency and developed by RTI International, the IPM model used by the Environmental Protection Agency and developed by ICF, and the NEMS model developed by the Energy Information Administration.

Table 3-2
Reference Transmission Expansion Parameters

U.S. Transmission Changes	
Historical experience for intra- and inter-region transmission increases (GW-miles)	
1982-1991	~15%
1992-2001	~5%
2002-2012	~20%
DOE Fleet Transition Project decadal limits	**Reference**
2010-2019	**10%**
2020-2029	**15%**
2030 & beyond	**20%**

Policies

Electric sector policies include existing state Renewable Portfolio Standards (RPS) requirements, the Cross-State Air Pollution Rule in 2015, as well as assumption of the Clean Air Act §111(b) compliance (i.e., no new coal units without CCS; this policy is assumed based on the expectation that some form of CO_2 regulation is highly likely to emerge over the timeframe modeled in this study). Environmental control costs represent the availability of different technologies and the policy flexibility to apply them for policies related to Mercury and Air Toxics Standards (MATS), cooling water, and coal ash (EPRI 2014). Lower SO_2 control costs assume that dry sorbent injection can meet HAPs (and later NAAQs) requirements. US-REGEN assumes a lower escalation in retrofit costs associated with extra time for MATS and Ozone compliance. The reference case does not incorporate the proposed Clean Power Plan or existing regional carbon markets (e.g., in California or New England). When the modeling reference case was established, the Regional Greenhouse Gas Initiative (RGGI) and California Assembly Bill 32 (AB 32) were excluded from the analysis, since their direction over multiple decades was less certain. Additionally, AB 32 is harder to model solely within context of a power sector model given its coverage of additional sectors and greenhouse gases. Tax and subsidy policies like the Federal Production Tax Credit for wind or the Federal Business Energy Investment Tax Credit for solar are not included in the reference scenario.

Generation Technologies

There are many technological assumptions associated with the US-REGEN reference case; technology cost and performance assumptions are taken from EPRI's Integrated Generation Options report (EPRI 2013d) (additional details on technology assumptions are provided in Appendix A):

- Nuclear
  - Instead of assuming a single lifetime across all nuclear units, approximately 80 percent of existing nuclear capacity in each region is assumed to have lifetimes extending to 80

years. The remaining 20 percent of the existing nuclear fleet is assumed to have 60-year licenses.

- Although new nuclear capacity can be built in the model, build limits on new capacity restrict deployment (see Table A-4, Appendix A)
- All nuclear capacity is considered must-run; any nuclear output variability is a results of month-specific availability factors.

- Coal
  - Existing coal facilities are assumed to operate as long as they are economically viable in the reference case. The sensitivity of the results to this assumption about endogenous retirement decisions for coal assets is explored in a case where coal lifetimes are limited to 70 years (as described in the next section).
  - Carbon capture and storage (CCS) retrofits with either 50 or 90 percent capture are assumed to be available beginning in 2025; same assumptions for CCS for new units. (This assumption is viewed as reasonable based on EPRI's extensive involvement in CCS technology research and development.)

3.3.2 Dynamic Model Scenarios

In addition to the reference case, there are three additional scenarios:

- **Low natural gas price trajectory:** This scenario uses the high estimated ultimate recovery (i.e., low gas price) trajectory from the 2014 Annual Energy Outlook. In contrast to the reference case, in which gas prices rise through 2040 to $7.73/MMBtu, the low-price scenario is relatively flat over time and reaches $4.90/MMBtu by 2040.
- **High natural gas price trajectory:** The high natural gas price scenario uses the low estimated ultimate recovery prices from the 2014 Annual Energy Outlook. Prices escalate over time and reach $10.26/MMBtu by 2040.
- **High natural gas price trajectory with no new inter-regional transmission:** This scenario assumes the same high gas price trajectory and also assumes that no new inter-regional transmission can be constructed over time. This limited transmission scenario reflects challenges associated with public acceptance, siting, or other region-specific factors that may be difficult to capture given the model's structure but nevertheless undermine the incentives for transmission investments (Joskow and Tirole, 2005).

As mentioned in the previous section, coal assets are assumed to operate while they are economic. Many units remain online throughout the time horizon for these cases, since there are no carbon pricing policies assumed. However, the remaining lifetimes of these assets are the product of many uncertain factors. Since a variety of difficult-to-model costs may shorten these lifetimes, the robustness of these conclusions are tested by assuming lifetimes of coal assets are limited to 70 years after they come online. This comparison offers insight into how shortened coal lifetimes may alter flexibility needs in later decades.

Another important sensitivity relates to how investments and operational flexibility change when cycling-induced system changes are taken into account. Cycling costs are not endogenous in US-REGEN (i.e., the model cannot chose whether to incur additional cycling costs or not through investments in variable generation). Therefore, the approach taken is to capture limitations for fossil units affecting their operational flexibility in terms of limiting minimum output levels and unit ramp rates in the unit commitment analysis.

3.3.3 Unit Commitment Analysis

Initial dynamic US-REGEN runs were used to provide inputs for unit commitment (UC) runs. Each UC run consists of a detailed analysis (i.e. unit-level representation of generation) of a selected region and concurrent analysis of all other regions with aggregated representation of generation assets in those other regions. Runs were made for two selected "detail" regions and in two future years. The UC analysis modeled hourly dispatch for all regions. The selection of regions and timeframes were motivated by questions of whether the transitioning generation fleet will evolve such that fleet operational flexibility capabilities will be adequate to support increasing variability in generation and demand. There are many applicable dimensions for selection, but the primary criteria were:

- Significant variable generation deployment
- Contrasting composition of generating fleet and significant renewable resources characteristics
- Transmission interconnection to other regions

Based on this list and preliminary scoping runs, the recommended regions for detailed UC analysis are the Northwest Central (NW-Central) region and Texas. The NW-Central region in US-REGEN includes the states of North and South Dakota, Nebraska, Kansas, Missouri, Iowa, and Minnesota. This region has the highest capacity factor wind resources in the country and the potential for transmission to neighboring regions, and its current fleet is dominated by coal-fired capacity. In contrast, Texas has a larger fraction of natural-gas-fired generators, potential for both wind and solar, and limited connectivity with other regions. The selected timeframes are 2015 (to give a portrait of current operations and to provide a baseline for comparison), 2025 (to understand grid operations in transition), and 2050 (to investigate longer-term transitions of flexibility needs under different resource mixes).

For each of the four dynamic scenarios, there are four corresponding UC runs for each of the two detail regions and time periods, as shown in Figure 3-7.

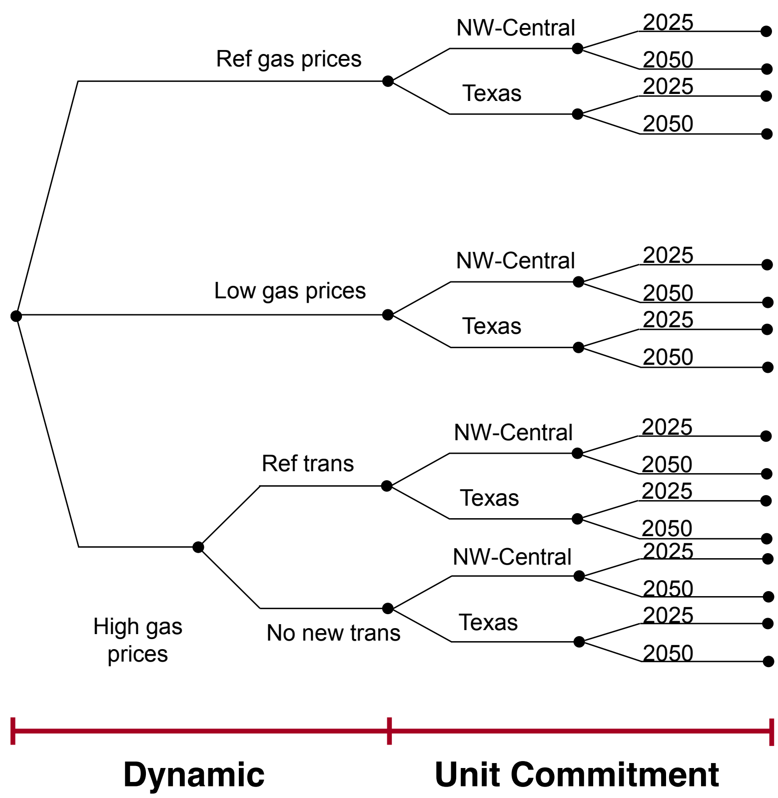


Figure 3-7
Scenario Tree

Table 3-3
Minimum Load by Unit Type

Unit Type	Minimum (% Unit Rating)
Coal	50%
Natural Gas (Combustion Turbine)	45%
Existing NGCC	60%
New NGCC	40%

Table 3-4
Ramp Up/Down Rate by Unit Type

Unit Type	Ramp Up/Down Limit (% Max/Hour)
Coal	50% / 60%
Oil	40% / 50%
Natural Gas	100% / 100%
Nuclear	30% / 30%

Table 3-5
Heat Rate Penalties at Minimum Load by Unit Type

Unit Type	Heat Rate Penalty
Coal	1.1
Oil	1.2
Natural Gas	1.2
Nuclear	1.2

3.3.4 Methodology for Analysis of UC US-REGEN Modeling Results

A metric called the "variability index" was created (see EPRI 2015) to compare spatial and temporal generating resource variability across different scenarios. By construction, this metric equals one during periods where resources have constant outputs (i.e., are not undergoing flexible operations) and equals zero during periods of extreme variability. We define this extreme flexibility regime as one in which an asset is ramped from its maximum available output to zero (or vice-versa) from one period to the next.[13] This index implicitly aggregates startups and ramps to offer a high-level metric for evaluating flexibility demands and their implied equipment stresses.

The variability index for a given capacity block ($i \in I$) at a specific time ($t \in T$) and region ($r \in R$) is defined by:

$$\boldsymbol{\gamma_{ir}(t) = 1 - \frac{1}{n(U_r)} \sum_{u \in U_r} \left[\frac{1}{n(S_t)} \sum_{s \in S_t} \frac{|\phi_u(s) - \phi_u(s-1)|}{\Phi_u(s)} \right]} \qquad \textbf{Eq. 3-1}$$

where $u \in U_r$ represents individual units in region r, $n(A)$ denotes the cardinality of set A, $s \in S$ represents the set of all hours (and $S_t \subseteq S$ is a subset of hours in period t). The innermost summand represents the absolute value of the hourly change in output of a specific unit $\phi_u(s)$. This difference is normalized by the maximum output in hour s of that unit:

$$\boldsymbol{\Phi_u(s) = \alpha_u(t) \cdot \bar{P}_u} \qquad \textbf{Eq. 3-2}$$

where $\alpha_u(t)$ represents the availability factor and $\bar{P}_u$ is the maximum unit capacity. For this analysis, the period of time t represents one week, which means that the hourly variability indices are averaged over the course of 168 consecutive hours. The equation assumes that the variability index for a capacity block (e.g., natural gas combined cycle units) equals the arithmetic mean of the values for individual units.

The unit commitment model also provides hourly capacity factors for individual units (in the detail region) or average hourly capacity factors for different blocks of generation assets in other regions. These data can be analyzed to provide an assessment of variability in unit output.

[13] Although this extreme variability is uncommon, it offers a theoretical bound for output variability that can be transparently defined and straightforwardly computed.

The variability metric and data regarding generation and capacity factor variability were used as inputs to the engineering assessment described below.

3.3.5 Engineering Assessment of Modeling Results

The complexity of flexible operations and their impact on generation units is not currently fully represented in capacity planning and unit commitment models. Therefore, this project included a separate engineering evaluation focused on subsequent analysis of the unit commitment model results and assessment of the feasibility of future levels of flexible operations as indicated in the modeling results. EPRI has carried out extensive research on flexible operations and their effects on component, system, and unit reliability, working closely with many power companies experiencing flexible operations across their generation fleets. This research has also included in-depth assessment of specific units and demonstration of methods for improving flexibility using operational trials. Combining this knowledge with a detailed review of the modeling results is intended to accomplish several goals:

- A better understanding of the levels of expected demand for flexible operations in the future generation fleet in different regions.
- A better understanding of the technical challenges from a fleet management perspective in meeting future flexible operations needs.
- Insights to future technology research priorities that would enhance fleet flexible operations capabilities and increase unit resilience.
- Identification of key issues associated with flexible operations requiring further analysis and modeling.

The engineering assessment focused on variability in unit operations from two perspectives: generation output and unit capacity factor. Regional results for all 15 US-REGEN regions were evaluated for the four major scenarios (reference, low natural gas price trajectory, high natural gas price trajectory, and high natural gas price trajectory + no new transmission expansion). For each scenario, unit commitment analysis results were evaluated for the future years 2025 and 2050. Since two different regions (Northwest Central and Texas) were analyzed in detail using UC US-REGEN, there are two separate sets of results for each combination of scenario and analysis year. In aggregate, 16 sets of unit commitment analysis results were considered (see Figure 3-5 above in section on UC US-REGEN approach.) Regional data from the unit commitment model analyses were subjected to a number of post-processing analyses to better help visualize and interpret results.

Assessment of Generation Variability

As noted above in the discussion of the approach taken with the UC US-REGEN model, a variability metric based on hourly unit generation variability was calculated. The trend for this metric was analyzed to evaluate the geographical and temporal extent, severity and frequency of flexible operations. The considerable volume of data resulted in development of a visualization tool referred to as a "heat map" in this study. Figure 3-8 provides an example heat map for generation variability. Heat maps are created for four generation technologies: combustion turbine combined cycle units, simple-cycle combustion turbine units, coal units, and nuclear units. In addition, a heat map is generated for the variability in energy transfer in/out of the region to adjacent regions. Each row of a heat map represents one of the 15 US-REGEN regions, and each column represents one of the 52 weeks in the year analyzed in the corresponding unit commitment analysis. The regions are ordered such that those names highlighted in blue (first five rows) roughly represents the eastern seaboard, those highlighted in green (next three rows) roughly represent the area between the Mississippi and the eastern seaboard states, the names highlighted in red (next three rows) roughly represent the Midwestern states, and the remaining names highlighted in grey (final four rows) represent the western states.

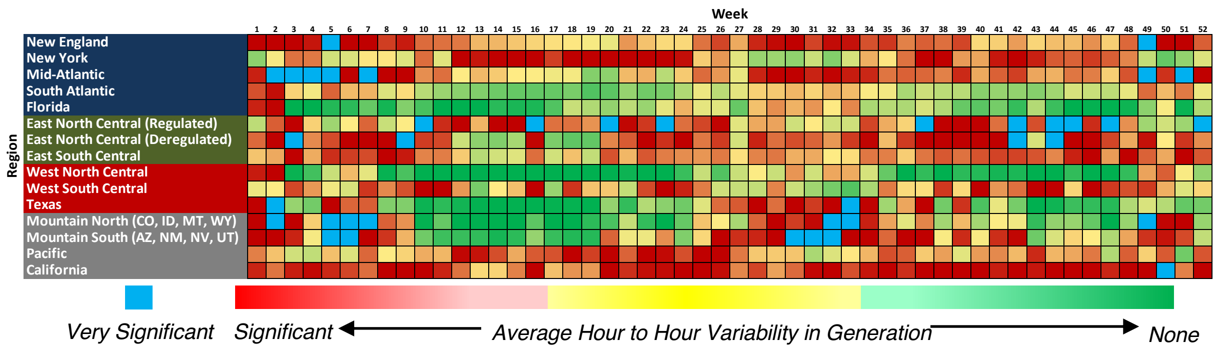


Figure 3-8
Example Generation Variability Heat Map

Each cell in the heat map is color-coded depending on average value of the hourly generation variability metric for a given generation technology (e.g. CTCC) over the course of the week (see section 3.3.4 for the quantitative definition of the generation variability metric.) Green indicates minimal variability, while red indicates significant variability. Bright blue indicates particularly high levels of variability.

The first part of the engineering assessment consisted of determining the criteria for assigning color-coding to each of the cells in the heat maps. The generation variability metric is defined such that decreasing values indicate increasing variability.

- A value of 1 for the generation variability metric indicates no change in average generation level from the prior hour, so this value was assigned to green.
- A value of 0.94 was assigned the mid-range color of yellow.
- A value greater than 0.88 and less than or equal to 0.9 was assigned the low end range color of red.
- Color shades between green and yellow, and between yellow and red represent metric values between the above mentioned limits
- A value of less than or equal to 0.88 was assigned the "outlier" color of blue.

Determining the above criteria required an analysis of different patterns of flexible operations in order to better understand the sensitivity of the generation variability metric. Although slightly counter-intuitive, the range of 0.88-1.0 for this metric encompasses nearly all values for this metric. Note that values < 1.0 imply significant levels of generation variability. To illustrate this further, a number of calculations were performed to determine the generation variability produced by six different types of flexible operations (some not necessarily operationally realistic), including time spent ramping between output levels. The corresponding generation flexibility metrics for these six patterns are summarized in Table 3-6 below to provide perspective on the range of expected values for the generation variability metric.

Table 3-6
Flexible Operations Patterns and Corresponding Generation Variability Metric Values

Flexible Operations Mode	Calculated Generation Variability Metric
Even distribution (i.e. equal time at 100%, 80%, 60%, 40%, 20%, 0% output)	0.964
Daily double shifting (i.e. 50% time at 100% output, 50% time at 0% output)	0.833
Weekend shutdowns (i.e. 5 days at 100% output, 2 days at 0% output)	0.988
Nightly minimum load (i.e. 50% time at 100% output, 50% time at 40% output)	0.950
Random distribution to test level of variability necessary to achieve very low variability metric (required operations at all output levels, significant time at low output levels)	0.655
Daily load following, nightly minimum load, weekend shutdown (i.e. ~48% time between 80-100% output, ~24% time at 40% output, ~28% time at 0% output)	0.855

These calculations suggest that heat map cells showing even moderate transition from green to yellow represent potentially significant levels of flexible operations. Keeping in mind that the generation variability metric is an average hourly value for an entire week for all units for a given generation technology type further suggests that if a variability metric less than 1.0 is observed, several units in that group may be experiencing even more significant variability, or there may be times during a week for which variability will be relatively higher.

Assessment of Capacity Factor Variability

The unit commitment modeling provides an hourly average capacity factor for all units of a given generation technology within a given region for a given week. Heat maps, organized by region and week as described above for generation variability, were created showing the average capacity factor value for each week. Each cell in the capacity factor heat maps is color-coded over a range of 0 to 1 for average capacity factor. Green indicates 1, while red indicates 0. In addition, the actual weekly average capacity factor value is shown.

This approach permits an assessment of the degree to which units experience cycling between different output levels, whether units operated for sustained periods at low output, and whether units experience variable lengths of shutdown between operations. Based on research by EPRI and others, all of these conditions are associated with equipment damage and operational challenges.

Aggregated Results from Engineering Assessment

Even after transforming the generation variability metric and capacity factor data into heat maps, 162 heat maps result when considering both generation variability and capacity factor for all combinations of the dynamic US-REGEN scenarios, the UC US-REGEN cases for the Texas and Northwest Central regions, the different years, and the different technologies. In aggregate, over 120,000 cells are contained in these heat maps.

Consequently, further aggregation of results was done to create a more integrated picture of the scope of future needs for flexible operations and to highlight specific areas where increased needs for flexible operations are expected to be particularly challenging. Review of all of the heat maps across all of the scenarios clearly indicated concentrations of higher levels of flexible operations in certain regions and time periods. Based on assessment of these patterns, it was determined that an appropriate further level of aggregation was to rate the severity of the flexible operations needs in terms of defined "super-regions" and seasons of the year. Four "super-regions" were defined based on the 15 US-REGEN regions:

- **East** (New England, New York, Mid-Atlantic, South Atlantic, Florida),
- **East Central** (North East Central-Regulated , North East Central - Unregulated, South East Central),
- **West Central** (Northwest Central, Southwest Central, Texas),
- **West** (Mountain North, Mountain South, Pacific, California)

Note that these groupings correspond to the color coded groups of regions shown in the heat maps (see Appendix C). The 52 weeks of the year were grouped into four 13-week seasons:

- Winter (Weeks 1-8,48-52)
- Spring (Weeks 9-21)
- Summer (Weeks 22-34)
- Fall (Weeks 35-47)

Based on this approach, each heat map can be viewed as consisting of 16 super-region/season blocks (in aggregate, over 2,700 blocks). For each generation variability and capacity factor heat map, each of these blocks were evaluated and rated high, medium, low, or negligible impact in terms of the severity of flexible operations indicated by the data. The ratings were based on EPRI domain expert knowledge of the relative operational, equipment damage/reliability, and staffing challenges associated with the types of unit operations implied by the generation variability and capacity factor data.

The results of this evaluation and rating process were tabulated in super-region/season tables for each technology, metric, and year. Comparing the 2015, 2025, and 2050 results suggested that much of the increased levels of operational flexibility manifest after 2025, so results were tabulated for 2015 and 2050.

In addition to the above aggregation approach, the evaluation also suggested that particular regions and weeks experience significant levels of flexible operations, so a separate evaluation was performed to identify those individual regions and weeks exhibiting particularly high levels of flexible operations. This additional evaluation identified which weeks consistently appeared to have a high degree of flexibility challenge, based on qualitative, subjective assessment of the metric results, across all scenarios, UC cases, technologies, and years. The goal was to assess whether there are specific periods in the year where a particularly chronic flexibility challenge is likely to persist. A similar evaluation was made to identify particular regions experiencing sustained high levels of flexible operations. The results of this evaluation were also tabulated.

Engineering Conclusions

Subsequent to completion of the above assessment of trends in flexibility metrics, results of the overall assessment were reviewed with a larger group of EPRI subject matter experts knowledgeable over a wide array of plant systems for both coal and gas unit operations and maintenance. This review provided several additional insights related to potential challenges associated with future increased levels of flexible operations.

Based on the engineering assessment and subject matter expert reviews, conclusions were developed addressing the following areas:

- Current/future technical challenges associated with flexible operations
- Feasibility of meeting future flexible operations needs
- Key priorities for future research to enable flexible operations

4 RESULTS

This section provides a summary of results for each phase of the project: literature review, dynamic US-REGEN modeling, unit commitment US-REGEN modeling, and the engineering assessment. These results are then integrated into a set of overall conclusions for the study. A separate section follows this one addressing future research needs.

4.1 Literature Review Results

The literature review, while generally not directly providing inputs for the modeling performed in this project, was highly valuable in confirming assumptions and various aspects of the technical approach. The literature review confirmed the need and validity for the approach taken in this project, i.e. an integration of long-term fleet transition and asset investment with unit commitment modeling. The key high-level insights from the literature review were as follows:

- Similar damage mechanisms caused by flexible operations were identified by both EPRI research and other research.
- Generally, the pattern of increasing flexible operations and operational challenges associated with increasing variability in demand (as seen by dispatchable, grid-connected assets) is consistent between the results of this project, EPRI research, and research by others.
- The capabilities of transmission system expansion and energy transfer between regions in response to flexible operations demands are clearly critical factors affecting the transformation of the future generation fleet.
- The key unit operational capabilities central to flexible operations are minimum output levels, and up and down ramping capabilities, and unit start times. Modeling these capabilities is essential for understanding the impact of flexible operations on future fleet transformation.
- In addition to assuring adequate flexible operations capabilities, the future generation fleet may also be challenged to expand in response to sustained moderate demand growth.

Appendix B provides a summary of key insights gained from the literature review for each of the documents included in the scope of the review. Each summary provides a citation for the document, a synopsis of the scope and topic of the document, a brief discussion of its relevance to this project, and a summary of relevant insights and/or data obtained from the review. An integration of the insights and data obtained collectively from all of the document reviews is summarized here.

As these reviews were completed, it became clear that their principal value could be classed into a few key categories particularly relevant to long-term energy-economic modeling of the current and future generation fleet:

- How to best understand and define flexible operations - This entailed both quantitative perspectives (e.g. frequency and number of start/stops, ramp rates, level of low turndown output) and qualitative perspectives (i.e. definition of specific flexible operations modes such as load-following, two-shifting, peaking, extended minimum load operations, etc.)
- Understanding cost impacts of flexible operations – how cost impacts are typically quantified, to what degree delayed impacts of flexible operations have been quantified, what the principal costs impacts might be (e.g. lost generation, lower efficiency, reduced availability, added O&M costs, added capital costs.)
- Understanding the impact of flexible operations on unit dispatch and operations.
- Key insights relative to analysis/ modeling

Based on this categorization, a cumulative summary of key insights from the literature review is provided in Table 4-1 below:

Table 4-1
Summary of Literature Review Insights

	Quantitative	Qualitative
Understanding / defining flexible operations	• A meta-analysis of existing literature[28] suggests that coal unit startup times can be characterized as follows: 12 hours (cold start), 4 hours (warm start), 1 hour (hot start), although it is noted that there is significant variance in the data. It is not clear whether this data considers potential added limitations associated with environmental controls.	• Generally, there is good consistency between EPRI research[20, 26, 30] and other research[7, 9,10,16,28] on the nature of damage effects due to flexible operations, and the different types of flexible operations modes. • Probability distributions of forced outage duration indicate that while boilers have highest probabilities, generators experience particularly long outages when they occur[16]. • A European study[32] notes that the effects of variable generation start to become apparent at generation shares above 2-3%. • An EPRI report[34] examining low turndown operations in a supercritical coal unit noted secondary superheater tube overheating when the unit utilized sliding pressure to achieve low turndown steam conditions.
Cost impacts of flexible operations	• Based on data from APTECH[9], a cold start is ~3x the cost of a hot start, and a warm start is ~2x the cost of a hot start. • One report[10] noted that unit auxiliary loads can increase from 0.5% to over 5% of total output for different modes of flexible operations.	• Considering the caveats and limitations of the historical data on which existing costs are based, cost impacts may be underestimated. • Reduced electricity production cost estimates associated with wind generation often neglect related costs: power purchase, capital, and O&M[2]. • Most studies[2,12] reviewed did not consider future asset investment, thus did not consider capital & O&M costs related to necessary backup generation.

Table 4-1 (continued)
Summary of Literature Review Insights

	Quantitative	Qualitative
	• One report[11] estimates that retail electricity rates would increase 9-23%, based on increasing a 33% RPS requirement to 50%. This same report estimates that corresponding transmission expansion requirements would range between $9-15B for a 50% RPS. Another report[12] indicated that a 30% RPS requirement results in addition of 3,000 miles of transmission at a cost of $14B.	• Many studies[14, 16] assume that costs due to cycling can be represented in terms of added equivalent hot starts, although the research[16] clearly indicates there is a delayed, cumulative component to damage effects. • Another important cost impact of cycling is reduced operational time, which limits the opportunity for added costs due to cycling to be recovered[14]. • Increased costs due to increased levels of unit ramping are non-linear as more ramping is required[16]. • Cold starts and low turndown operations are the principle drivers of added cost due to cycling[16]. • Much of what is known about cycling costs is based on research by Intertek-APTECH, which is based on historical data accumulated through their services work. Several aspects of this data suggest that future costs due to cycling, when more widespread and affecting much larger portion of the fleet, may not necessarily be consistent with past costs[16], e.g. very little data on supercritical coal unit cycling, limited data on "deep cycling" (load-following from near minimum to near maximum output), much of historical data based on gas-fired steam units. • Data[16] on the distribution of capital & maintenance cycling costs per MW as a function of unit capacity indicate that these costs are relatively insensitive to unit capacity. • Uncertainty in the sustainability of demand response measures translates to the necessity to invest in additional resources to provide alternative ancillary services[23].
Impact of flexible operations on unit dispatch and operations	• In one study[2], aggregate reserve requirements are significantly larger for high levels of wind penetration: – regulating reserve ~40% larger – spinning reserve requirement ~50% larger	• Reliability-focused studies[2, 15, 18] indicate that no real market mechanisms exist which assure high levels of inter-regional coordination and planning necessary to maintain adequate reliability. Several studies also note that absence of market features that adequately value ancillary services and flexible operations[6]. Consequently, evolution of the generation mix to one that may be deficient in terms of operational flexibility is quite possible.

Table 4-1 (continued)
Summary of Literature Review Insights

	Quantitative	Qualitative
	• Another report[12] indicated that for a 30% RPS nationally, the regulation reserves would have to increase from 1,200 MW to 2,700 MW. • Load growth in the Eastern Interconnect likely to average ~1%/year[3]. • In one study[5], very high levels of wind capacity additions necessary to achieve high levels of wind generation: – 225GW to achieve 20% generation share – 330GW to achieve 30% generation share • An NREL paper[9] observed that on average, every 3 MW of additional variable capacity results in reduced output from 1 MW of dispatchable assets and decommitment of 2 MW of dispatchable assets. • A European paper[19] notes that the hourly volatility of the load net of renewables generation is on the order of 25-100%. • An EPRI report[20] notes that for successful post-combustion CO_2 capture (PCC), minimum extraction pressure must be maintained (typically ~60 psia for mono-ethanolamine PCC systems.)	• Significant increases in renewable generation may result in less operation or retirement of conventional resources due to economic reasons, which reduces the population of dispatchable assets capable of supporting flexible operations needs[5, 12, 18]. Similarly, increased uses of demand response can also adversely affect capacity payment revenue for peaking generation resources, potentially resulting in lower investments and reduced availability for such resources[23]. • Large amounts of wind generation can create significant operational issues[6,18]: – Frequency deviations due to fast ramping (by both wind and supporting assets) – Higher ancillary service requirements (spinning, regulating reserves) • Off-normal operations of unit emissions controls in different flexible operations modes results in added cost and reduced emissions control efficiency[10]. In addition, operations of CO_2 systems under flexible operations requires specific design and operational measures[20]. • Several studies[11] note that renewable generation curtailment is necessary to ensure grid stability when renewable generation levels are high. • High renewables penetrations appear to principally drive more low turndown operations and cold starts in dispatchable units[16]. • A design strategy for increasing operational flexibility for solvent-based PCC systems is larger solvent regeneration tanks, creating margin for available solvent under a range of operating conditions[20]. Associated with this approach are important design considerations: – Maintenance of “rich” solvent (i.e. solvent with captured CO_2) at or slightly below absorber bottom outlet temperature to avoid de-gassing and potential tank over-pressurization – Maintenance of an N_2 or CO_2 blanket in solvent regeneration tank to avoid solvent degradation due to reaction with O_2. • Another important consideration for sustained and widespread flexible operations is the impact on plant staffs and the need for communications around new operational missions and for new staff training[21].

Table 4-1 (continued)
Summary of Literature Review Insights

	Quantitative	Qualitative
	• Energy storage represents ~2.3% of total U.S. capacity currently, suggesting that it generally plays a small role in ameliorating challenges due to operational flexibility[22]. • One paper[23] references a FERC study indicating that potentially 19% of all load could involve some level of demand response by 2020.	• Extended coal unit layup periods may result in extended coal storage programs, which increases the risk of bunker/silo fires[21]. • Advances in communications and controls have resulted in increased reliance on demand response, potentially contributing to added variability to load served by dispatchable resources[22]. • Inherent uncertainty in the sustainability of demand response as a resource and the resulting difficulty of incorporating demand response into long range planning potentially creates additional future volatility in load served by dispatchable resources[22].
Key insights relative to analysis/ modeling		• A potentially important factor in fleet transition analysis is the effect of bilateral purchase agreements (which affect energy flows) [4]. • Several studies acknowledged the necessity for unit commitment analysis in order to model unit operational constraints[4, 5, 15, 27]. • The concept of a non-sequential, condensed representation of the load curve used in the US-REGEN dynamic model is validated by independent research[27]. • While studies make generic assumptions about or neglect transmission expansion, this is an important consideration. Several reports either assumed or concluded that substantial transmission expansion is necessary to support high levels of wind and/or solar generation[4, 5, 12]. One study[17] noted that proposed renewable capacity expansion outpaces planned transmission expansion, suggesting significant potential for increased future transmission congestion. This same study also notes that much of the existing transmission infrastructure is aging and will require replacement before 2030. • Although many studies neglect inter-regional energy transfers, this is a key factor[4, 14, 15]. • A number of reports suggest that aggregation of generation blocks to improve computational speed is an acceptable approach[4, 9, 24]. • A key added complexity not typically addressed in modeling is consideration of AC power flows, voltage and reactive power compensation, dynamic and transient stability, and HVDC terminal control[5].

4.2 Modeling Results

As described in the approach outlined in Section 3 above, the modeling consisted of two major elements: use of the dynamic version of US-REGEN to analyze the future generation mix under different scenarios, followed by unit commitment analysis using UC US-REGEN of specific future years to investigate the degree to which flexible operations will be needed in the future. It is clear from the results that substantial levels of flexible operations are very likely necessary to support the future US generation fleet.

4.2.1 Dynamic US-REGEN Modeling Results

Table 4-2 summarizes the 4 scenarios analyzed in the dynamic US-REGEN modeling; Section 3.3.2 describes these scenarios.

Table 4-2
Dynamic US-REGEN Scenarios

Scenario	Description
REF	Reference scenario
LOGAS	Low natural gas price trajectory (from EIA AEO 2014)
HIGAS	High natural gas price trajectory (from EIA AEO 2014)
HIGAS_NOTR	HIGAS scenario + no expansion of existing inter-regional transmission capacity

National Results

An overview of the future generation fleet in terms of generation, capacity, and inter-regional transmission at the national level facilitates interpretation of results for specific regions (i.e. Texas and Northwest Central). As noted in Section 3.1, the US-REGEN model endogenously calculates the deployment of new generation assets, including renewables, as a function of economic and policy conditions, technology cost and performance assumptions, and policy assumptions. Therefore, the capacity and generation shares for renewable energy is an output of the analysis. The figures and discussion below provide this overview. (Note that “environmental retrofit” shown in these figures refers to coal that was retrofitted for compliance with existing regulations assumed as part of the reference scenario.)

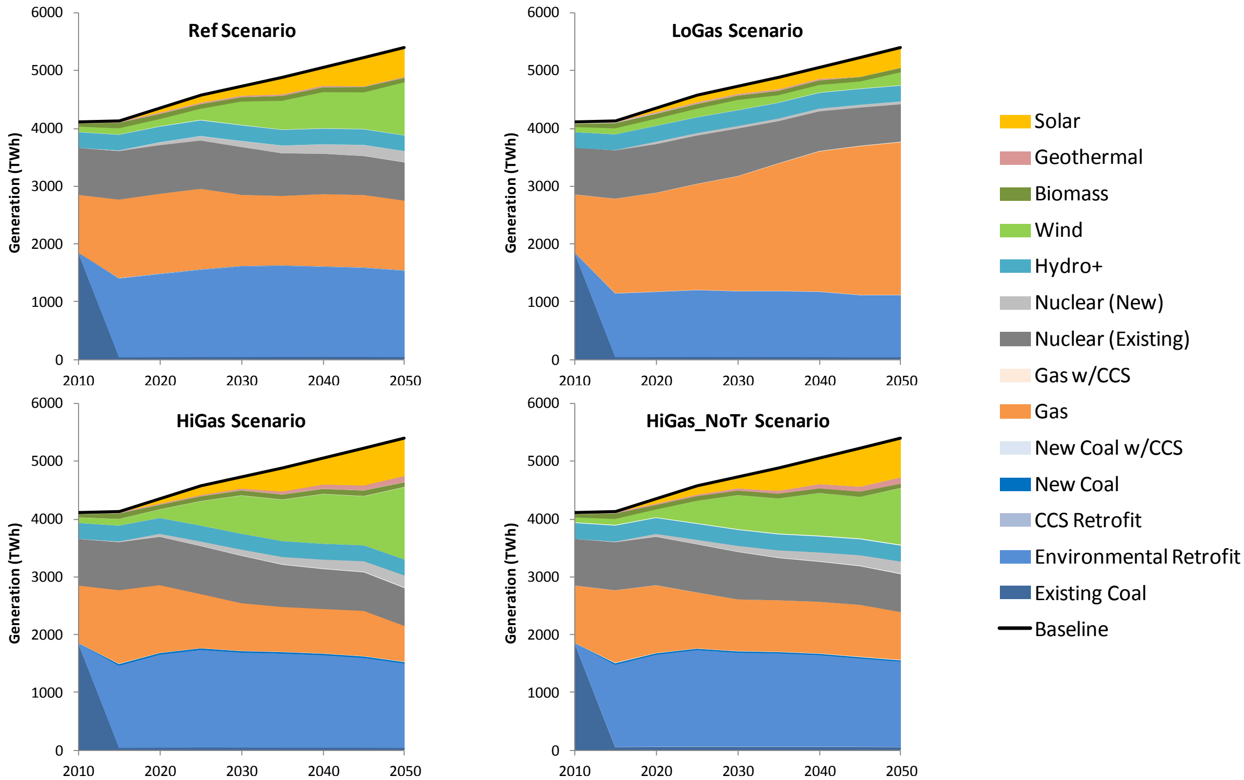


Figure 4-1
National Generation Mix by Technology through 2050 for All Scenarios

For the reference scenario (upper left panel of Figure 4-1), environmental retrofits occur for most existing coal units by 2015, and the remaining capacity largely stays online throughout the scenario. Generation from natural gas stays comparatively flat. Growing demand and capacity retirements are met by new wind, solar, and nuclear depending on which technology is on the margin in different model regions. For the low gas price scenario (upper right), natural gas combined cycle units comprise most of the generation growth. The competitive position of gas forces the endogenous retirement of some coal capacity in the early years of the scenario. Renewable deployment is modest in this scenario and occurs primarily to meet regional renewable portfolio standards. For the high gas price scenario (lower left), more generation comes from wind and solar compared with the other scenarios. Generation from these resources displaces natural gas. For the high gas and no new transmission scenario (lower right), the generation mix is similar to the high gas price scenario. Generation from some wind is displaced by natural gas, since the wind resources cannot be transferred as easily from the resource base to the load centers.

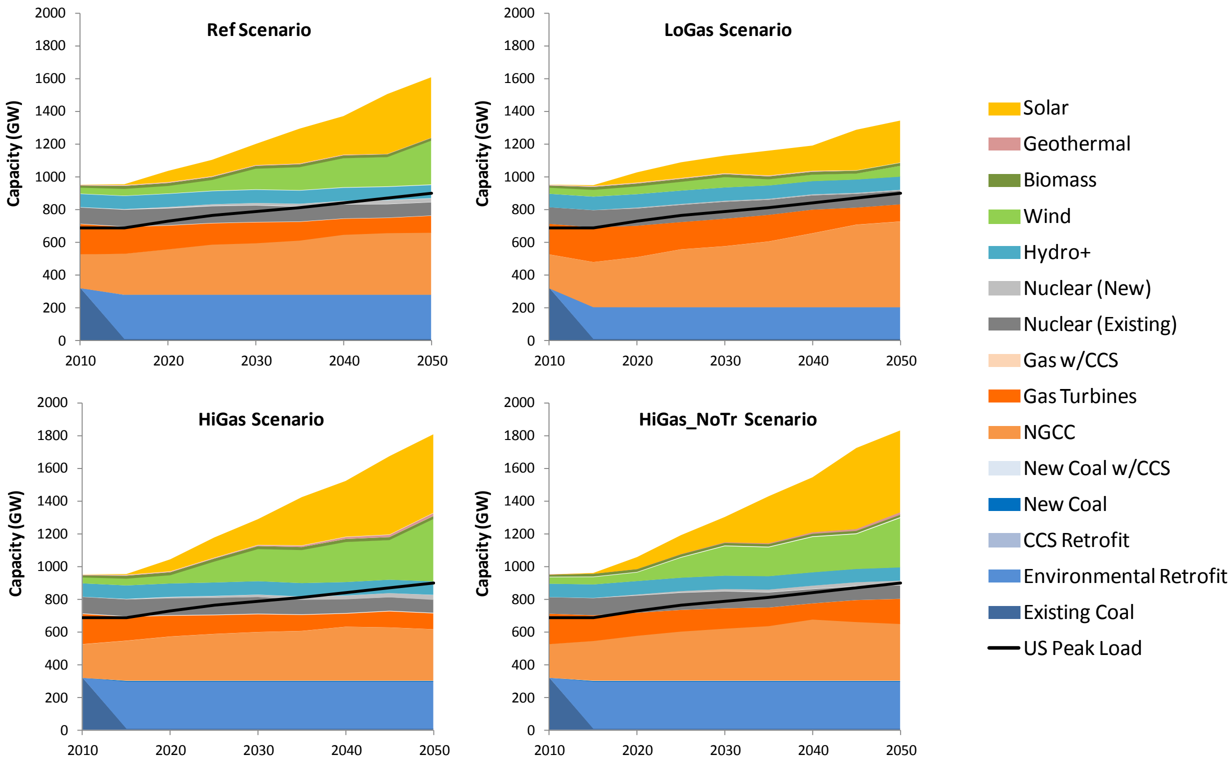


Figure 4-2
National Capacity by Technology through 2050 for All Scenarios

The parallel story about capacity deployment in Figure 4-2 looks qualitatively similar to generation. The black lines on these figures represent national peak load over time. These lines indicate the surplus capacity that may be used to meet peak load and illustrates the degree to which intermittent renewables can contribute to balance-of-systems and resource adequacy. In some cases, installed capacity may be double the peak load due to the intermittency of wind and solar and their low capacity values.

The inter-regional transmission results highlight the significant role that transmission plays in enabling a future generation fleet operating with much higher production from renewable generation assets. Figures 4-3 and 4-4 show 2050 inter-regional energy transfers and transmission capacity additions (if permitted). Table 4-3 shows the magnitude of net inter-regional transfers, and Table 4-4 shows the ratio of inter-regional imports and exports in 2050 to those values for 2010. These tables show the substantial growth in demand for transmission, as well as significant features of where imports and exports are likely to move:

Table 4-3
2050 Inter-Regional Energy Transfers* (TWh)

	Scenario			
Region	**REF**	**LOGAS**	**HIGAS**	**HIGAS_NOTR**
New England	(0.9)	(0.6)	(2.5)	(2.7)
New York	2.3	(0.3)	16	6.0
Mid-Atlantic	(0.4)	(3.8)	13	0.2
South Atlantic	26	(0.1)	9.7	16
Florida	38	166	43	23
Northeast Central	37	9.6	33	(15)
Southeast Central	14	(166)	37	(11)
Northwest Central	(76)	1.9	(114)	(39)
Southwest Central	7.3	(1.8)	28	28
Texas	(70)	(6.1)	(73)	(5.8)
Mountain North	(20)	(3.6)	(44)	(9.4)
Mountain South	(39)	(6.5)	(81)	(46)
Pacific	13	(4.7)	25	7.7
California	69	16	111	47

*Positive value => net import to region; negative value (shown in parentheses) => net export from region

Table 4-4
Ratio of 2050/2010 Regional Imports and Exports

	Scenarios							
	REF		LOGAS		HIGAS		HIGAS_NOTR	
	Export	Import	Export	Import	Export	Import	Export	Import
New England	0.35	*0 to 0.3**	0.36	*0 to 0.6**	1.2	*0 to 1.6**	0.88	*0 to 0.2**
New York	1.0	0.26	1.4	0.14	2.5	1.2	1.5	0.55
Mid-Atlantic	0.99	0.97	0.50	0.31	1.4	2.0	0.94	0.95
South Atlantic	1.3	0.73	0.43	0.12	2.8	0.66	1.3	0.55
Florida	*0 to 8.7**	1.6	0 (no change)	5.8	*0 to 11**	1.9	*0 to 2**	0.87
Northeast Central	0.66	13	0.14	3.1	1.1	18	0.69	5.9
Southeast Central	1.8	2.2	5.3	0.30	2.0	3.1	1.2	0.83
Northwest Central	4.4	5.4	0.37	3.4	6.3	6.3	2.1	1.8
Southwest Central	7.5	3.2	1.5	0.50	8.1	4.3	1.6	1.8
Texas	73	12	12	4.8	78	14	6.3	1.1
Mountain North	3.0	12	0.98	6.1	5.0	11	1.2	3.9
Mountain South	1.3	17	0.31	5.2	2.0	19	0.84	3.0
Pacific	0.80	2.8	0.74	0.75	0.65	3.9	0.70	2.1
California	*0 to 9.4**	0.99	*0 to 6.5**	0.29	*0 to 9.8**	1.5	*0 to 0.2**	0.75

*Entries indicating "0 to value" indicate 2010 value was ~ zero.
** Red values => ratio > 10; orange values => 10>ratio >5 ;yellow values => 5>ratio>2

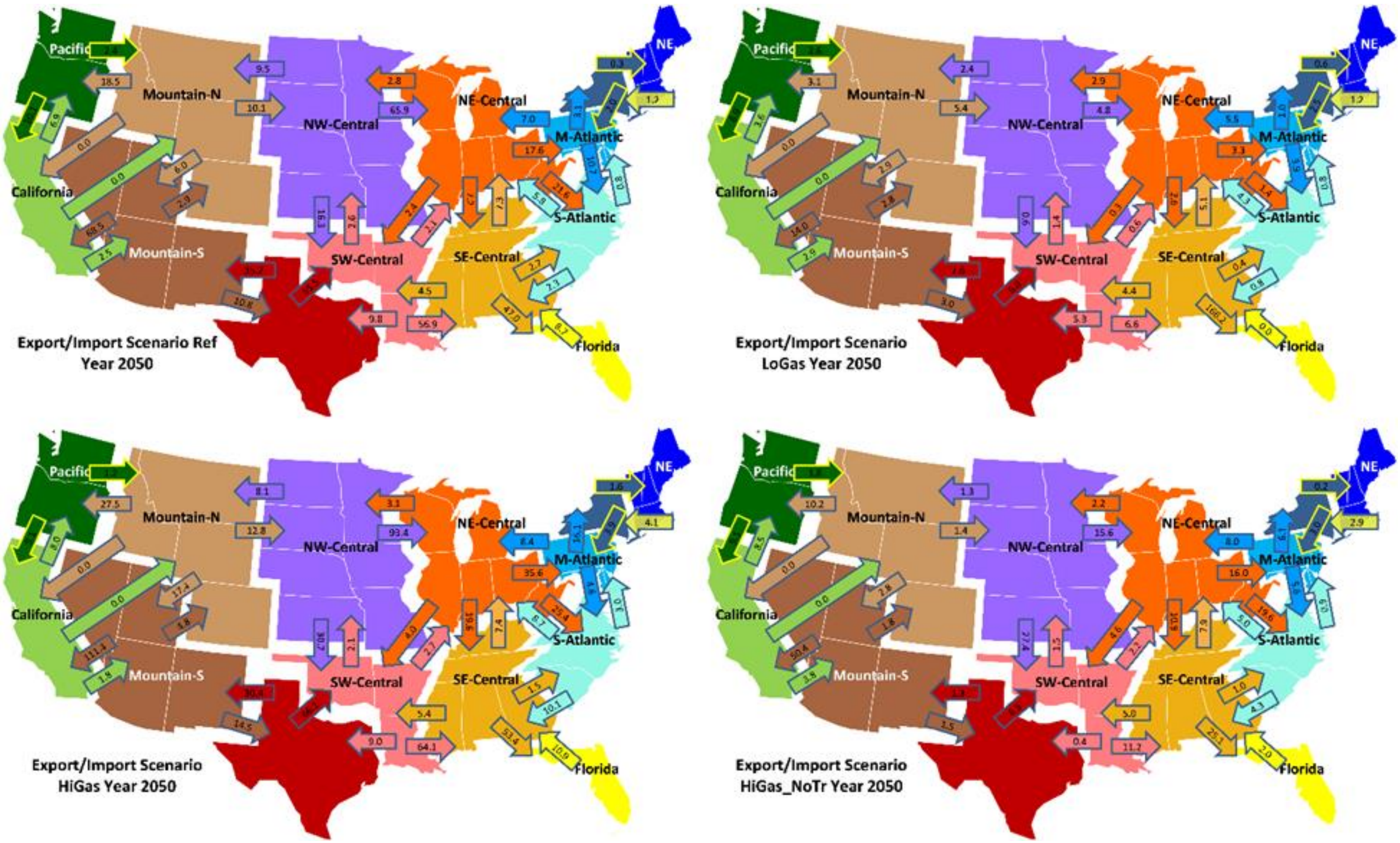


Figure 4-3
2050 Inter-Regional Energy Import/Export (TWh)

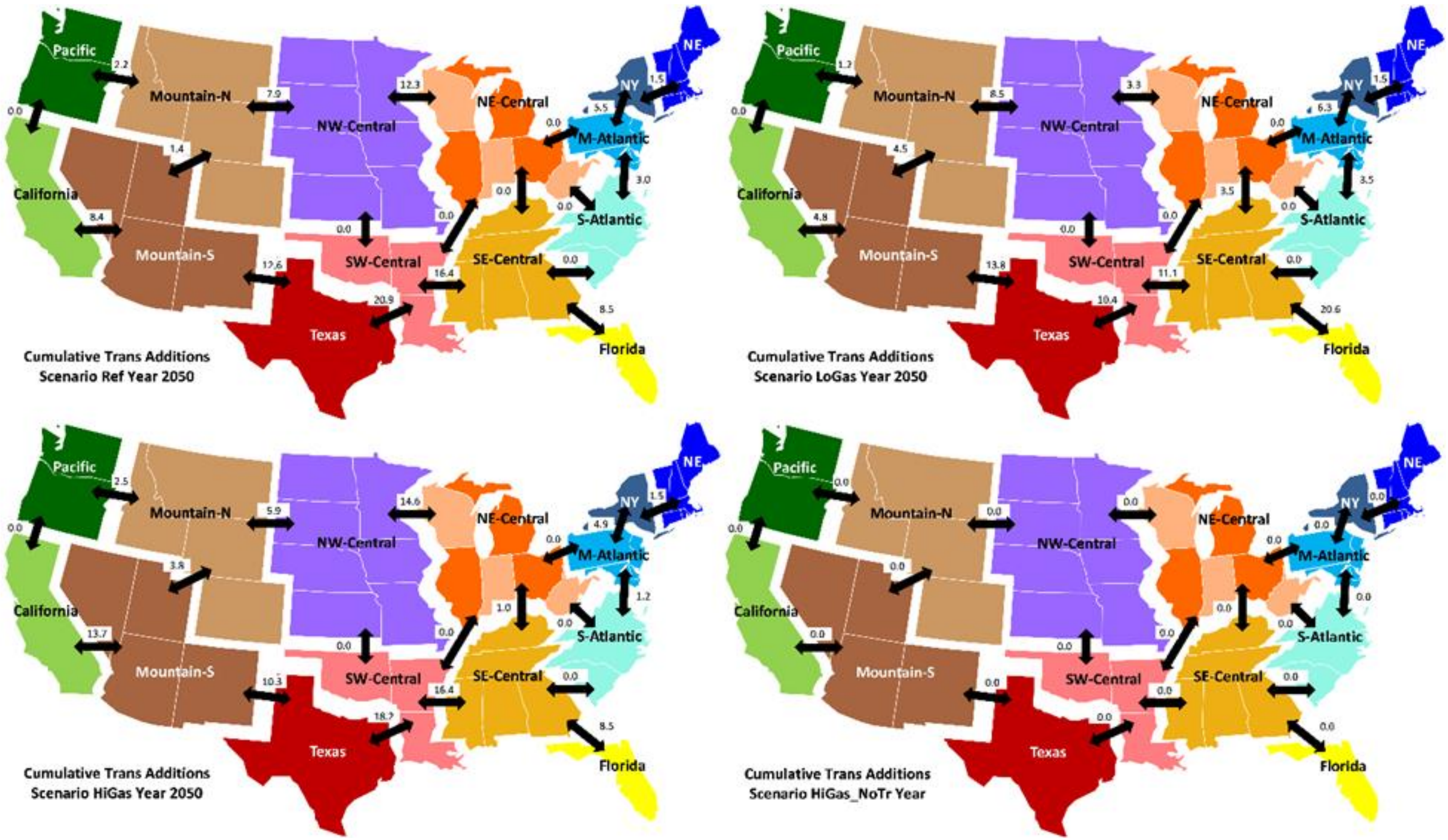


Figure 4-4
New Transmission Capacity Additions by Region by 2050 (GW)

Discussion of Generation, Capacity Mix for "Detail" Regions

As discussed in Chapter 3, the UC US-REGEN analyses generated unit dispatch analyses for selected future years for all scenarios and regions, with detailed unit level analysis for selected regions. To ensure consistency of results, two different "detail" regions were selected (Northwest Central and Texas), and the entire set of UC US-REGEN analyses were repeated for each detail region.

The NW-Central (NWC) states are a region of interest for this analysis due to their large wind resources and expected wind capacity deployment, as seen in the reference scenario (Figure 4-5). Figure 4-6 gives a sense of interconnection issues for NWC and its net trade position (i.e., usually as an exporter) given that load is lower than in-region generation. The low gas price case offers insights about the strong competitiveness of coal in the region, as low gas prices erode wind's generation share but not coal generation. Since we are examining unit commitment analyses for 2025 and 2050, we can see how 2025 is a period on the cusp of transition in many of these cases, since it has a very similar generation profile to 2015. In 2050, however, grid mixes across the board illustrate systems with unique operational challenges, whether it is due to large percentage of renewables or due to exports.

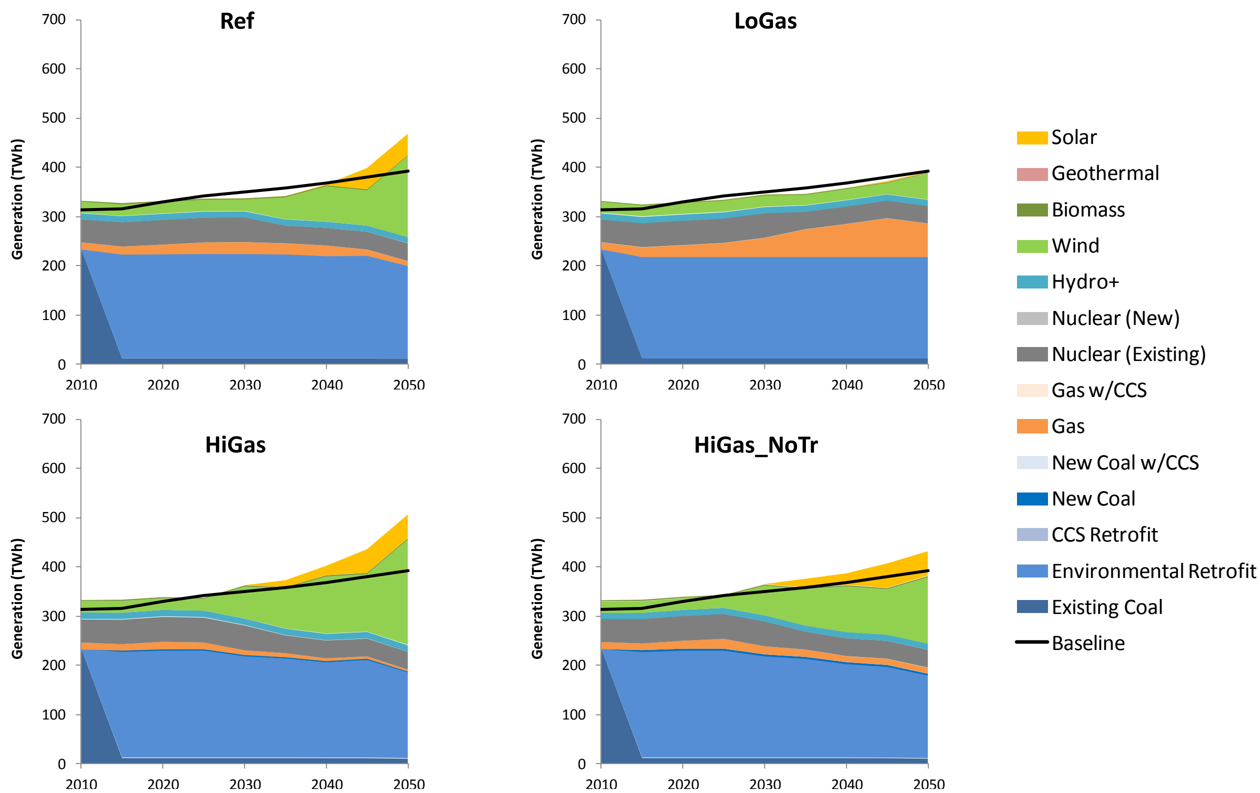


Figure 4-5
Generation Mix for the NW-Central Region by Technology through 2050 for All Scenarios

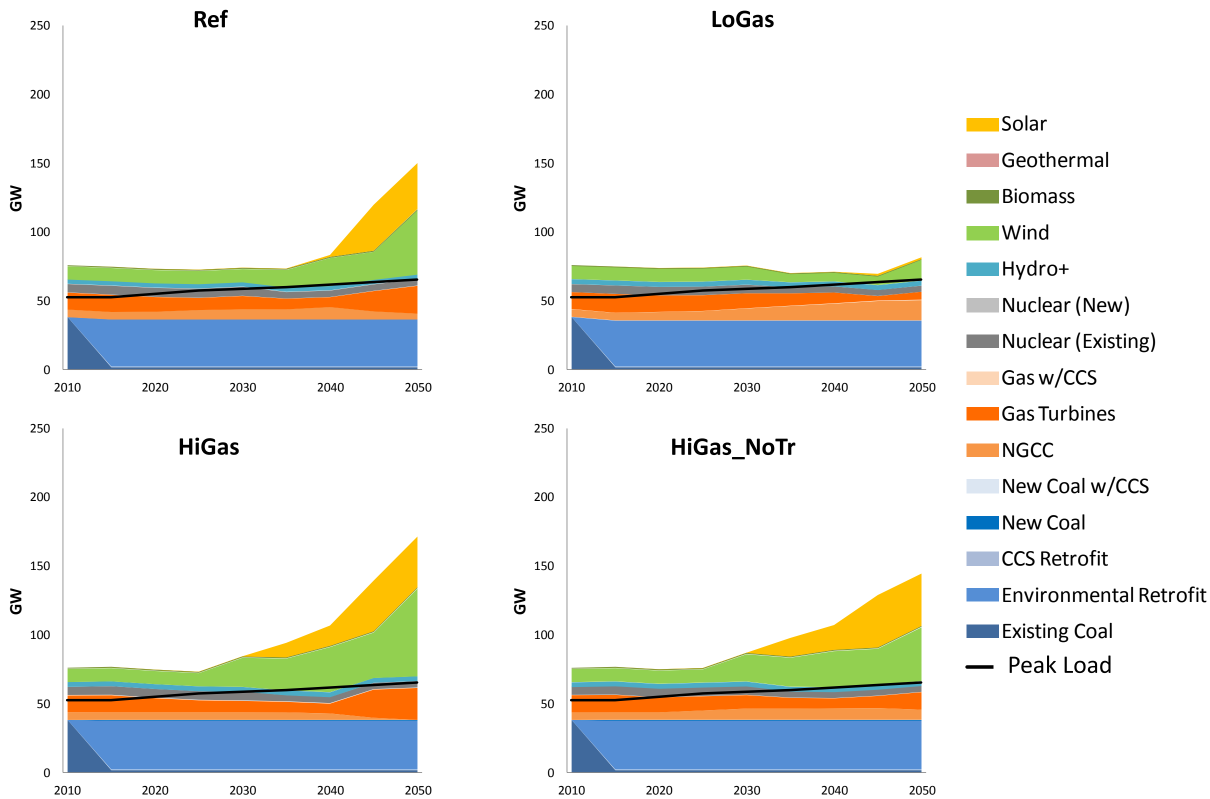


Figure 4-6
Capacity Mix for the NW-Central Region by Technology through 2050 for All Scenarios

Texas is a region of interest for many reasons, as illustrated in Figures 4-7 and 4-8. First, the region is projected in the US-REGEN reference case to have considerable renewable generation (though the extent/timing depends on the scenario assumptions). Unlike the NW-Central renewable mix, which is largely wind, Texas has both wind and solar deployment. Also, the non-renewable components of the generation fleet in Texas are dominated by natural gas and nuclear, as opposed to coal. Second, given the region's relative isolation at present, the alternate transmission scenarios provide insights as to the role and importance of transmission.

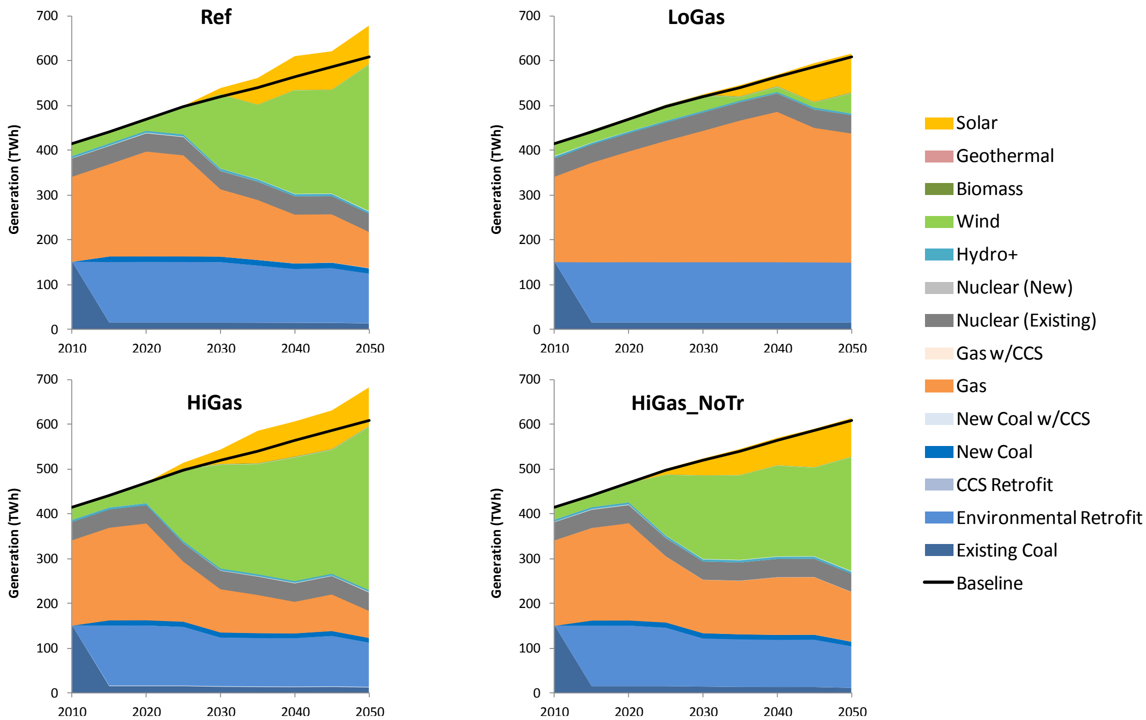


Figure 4-7
Generation Mix for the Texas Region by Technology through 2050 for All Scenarios

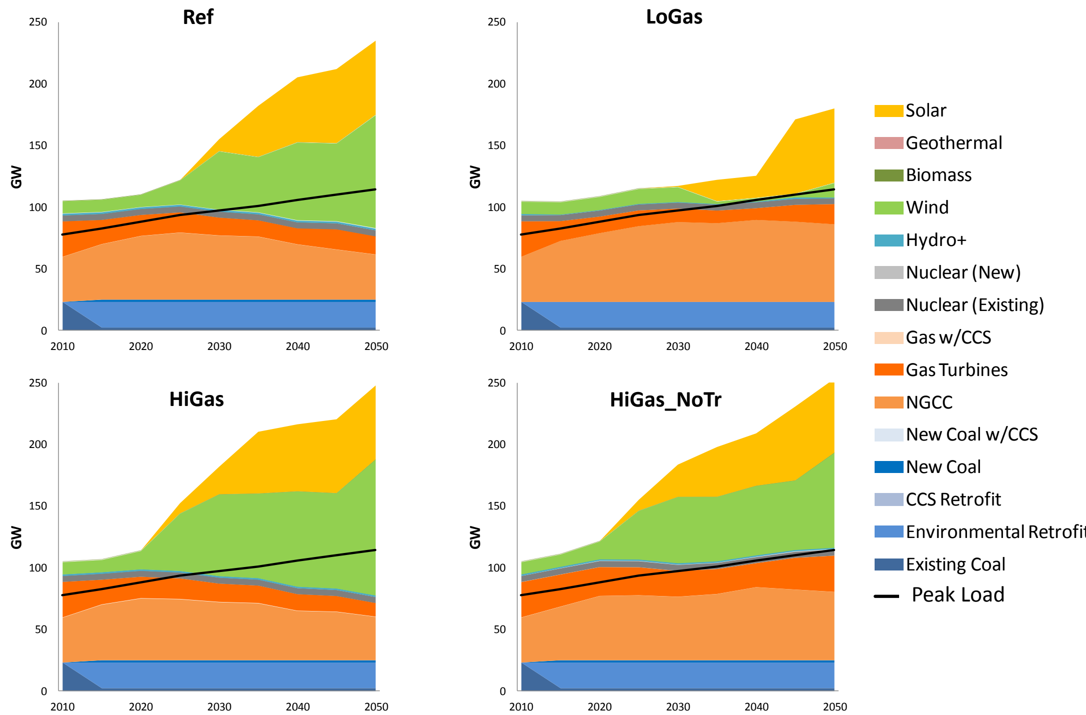


Figure 4-8
Capacity Mix for the Texas Region by Technology through 2050 for All Scenarios

Discussion of Sensitivity to Limited Coal Unit Lifetime

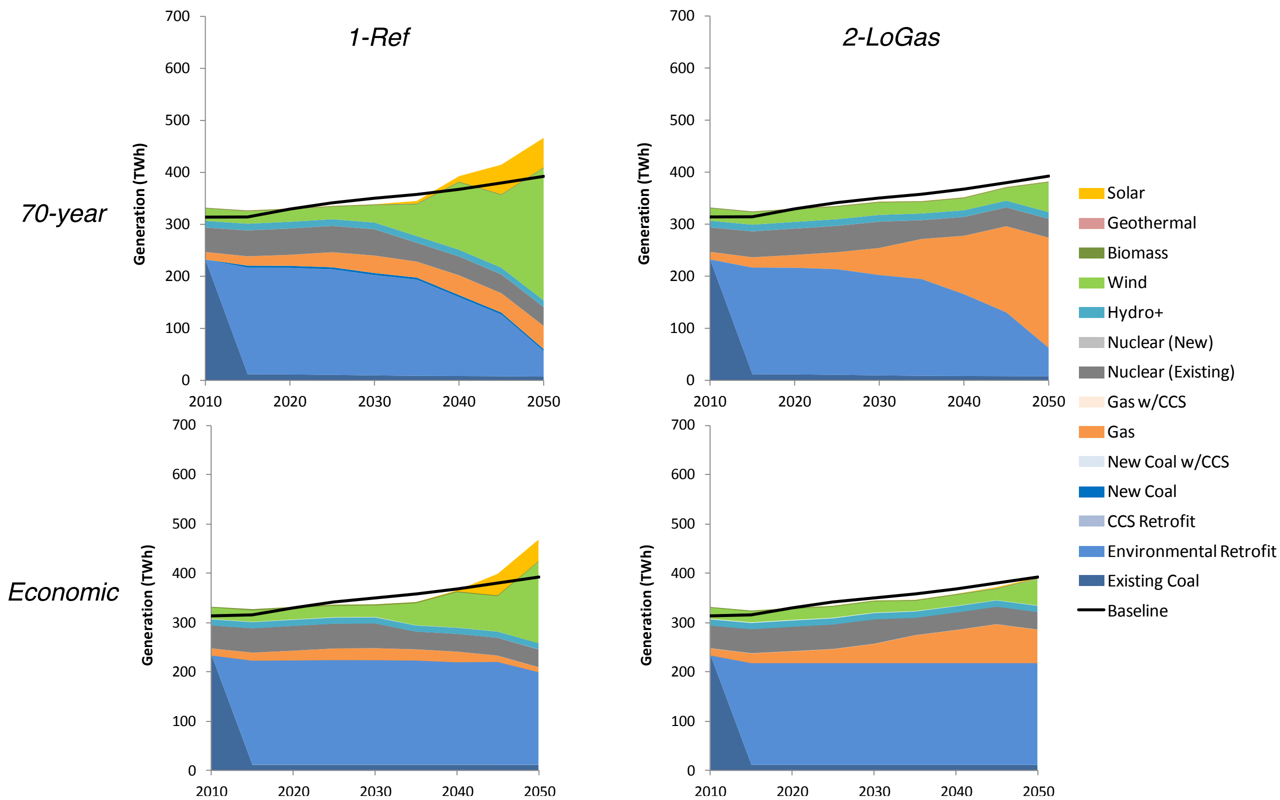


Figure 4-9
Generation Mix for the NW-Central Region with Alternate Assumptions about Coal Lifetimes

Given that the average age of units in the current U.S. coal fleet is roughly 40 years, the likelihood that a sizeable portion of this fleet will continue to operate well into the future is strongly dependent on the willingness of asset owners to invest in these units late in life. This is particularly true given a robust set of existing and emerging environmental regulations. Therefore, a sensitivity study was performed using dynamic US-REGEN to assess how the future generation mix might be different if coal units were limited to a 70 year lifetime, after which retirement is assumed. With this assumption, a large portion of the existing coal fleet would reach retirement between 2040 and 2050. Figures 4-9 and 4-10 show results for NW Central and Texas with the 70 year coal unit lifetime assumption, comparing the reference and low gas price trajectory scenarios. These two scenarios are compared because the sensitivity study suggests that either renewables or combined cycle generation replace that lost by coal, depending on natural gas prices. The effect is more pronounced in regions that are more coal dominated, like NW Central. The conclusion is that significant coal retirements would drive greater renewables generation shares, which would likely increase the need for flexible operations by dispatchable assets even further.

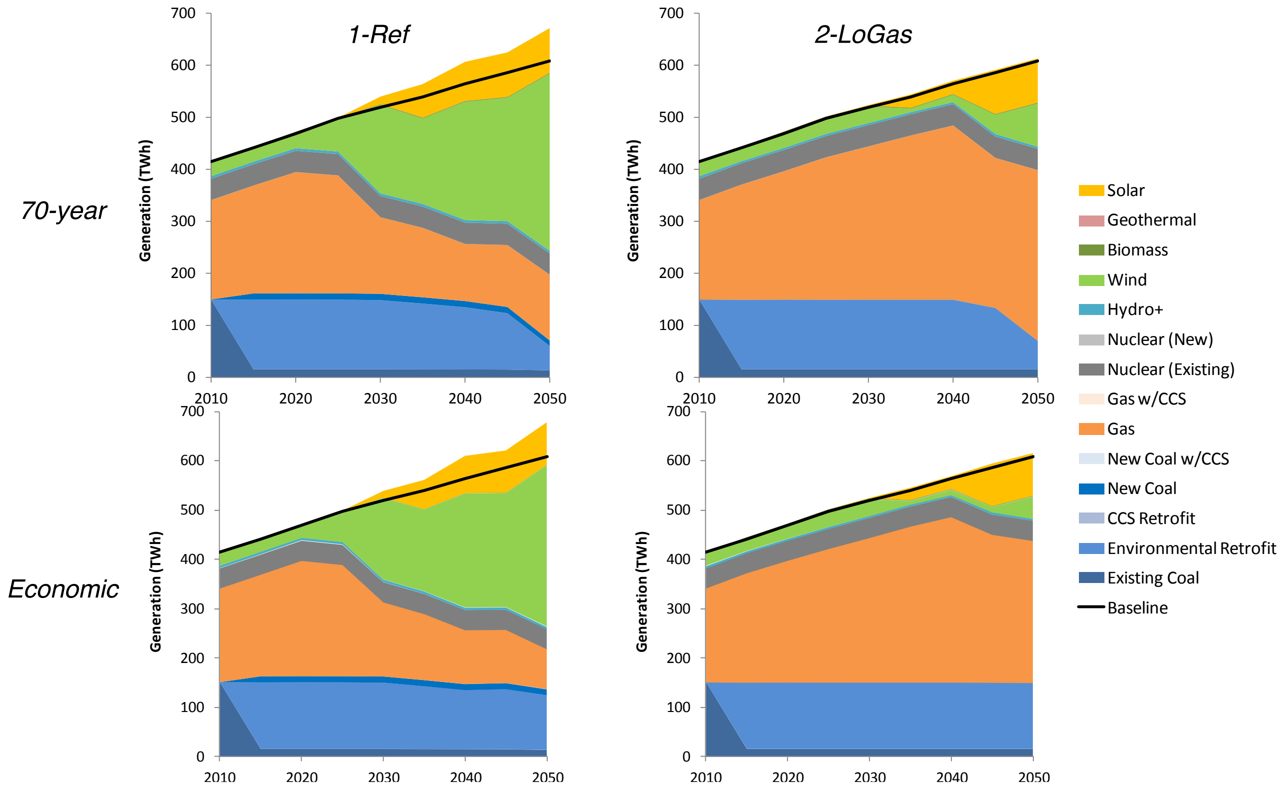


Figure 4-10
Generation Mix for the Texas Region with Alternate Assumptions about Coal Lifetimes

4.2.2 Unit Commitment US-REGEN Modeling Results

Table 4-5 summarizes the detail regions and years analyzed in the UC US-REGEN modeling; Section 3.3.3 describes these scenarios.

Table 4-5
UC US-REGEN Analyses

Dynamic US-REGEN Scenario	UC US-REGEN Detail Region/Year
REF	TX (2015, 2025, 2050); NWC (2015, 2025, 2050)
LOGAS	TX (2015, 2025, 2050); NWC (2015, ,2025, 2050)
HIGAS	TX (2015, 2025, 2050); NWC (2015, 2025, 2050)
HIGAS_NOTR	TX (2015,, 2025, 2050); NWC (2015, 2025, 2050)

The unit commitment model (UC US-REGEN) generates detailed data regarding hourly dispatch of all asset types in each of the 15 regions. As noted in Chapter 3, UC US-REGEN analyzes a selected region at unit-level detail, while analyzing the generation in other regions concurrently in terms of blocks of generation of similar type and vintage. Figures 4-11 through 4-20 provide results for the reference scenario for the two selected "detail" regions (Texas and Northwest Central). The detailed data from the unit commitment analysis provide the basis for calculation of the generation variability metric and capacity factor inputs to the heat maps discussed in Chapter 3. For each region, four different aspects of the unit commitment analysis results are presented:

- Comparison of the hourly generation in the region in 2015, 2025, and 2050 for the high and low demand weeks during the year. This provides a perspective on the trend in generation mix changes and variability in generation from different asset types over time.
- Comparison of hourly ramp duration curves by generation type in 2015 and 2050. This shows the degree to which different asset types spend more time ramping in 2050 vs. 2015.
- Comparison of hourly ramp duration curves for load, variable generation and net load in 2015 and 2050. ("net load" is the residual load remaining after variable generation is subtracted from in-region demand for each hour and designates electricity demand that must be met through dispatchable resources.) This provides another perspective on how ramping needs increase as a result of changing load and increased generation from variable resources, resulting in more ramping for dispatchable resources.
- Comparison of the hourly generation in the region in 2025 across all four scenarios for the high and low demand months during the year. This provides a perspective on the trend in generation mix changes and variability in generation across the four scenarios.

These results are presented to provide insight to the detail underlying the aggregated analysis presented in the form of the heat maps and their subsequent evaluation.

UC US-REGEN Results for Texas

Figure 4-11 shows that for both the low and high demand weeks in a given year, variability significantly increases between 2015 and 2050. By 2050, solar and wind generation shares are so large that their variability profoundly affects the response from other assets. For the low demand week, there is virtually no gas generation and the coal assets have several periods of very low output. For the high demand week, the combined cycle assets absorb the variability in 2050 by essentially turning on/off for narrow intervals during the week. Note also that in the low demand week in 2050, wind generation significantly exceeds demand, thus implying likely exports from the region. For the high demand week, there are large number of hours where demand is greater than generation, implying that the region would need highly flexible imports to support demand. Note also that while curtailment of renewables may occur, the amount of curtailment is not depicted on these charts.

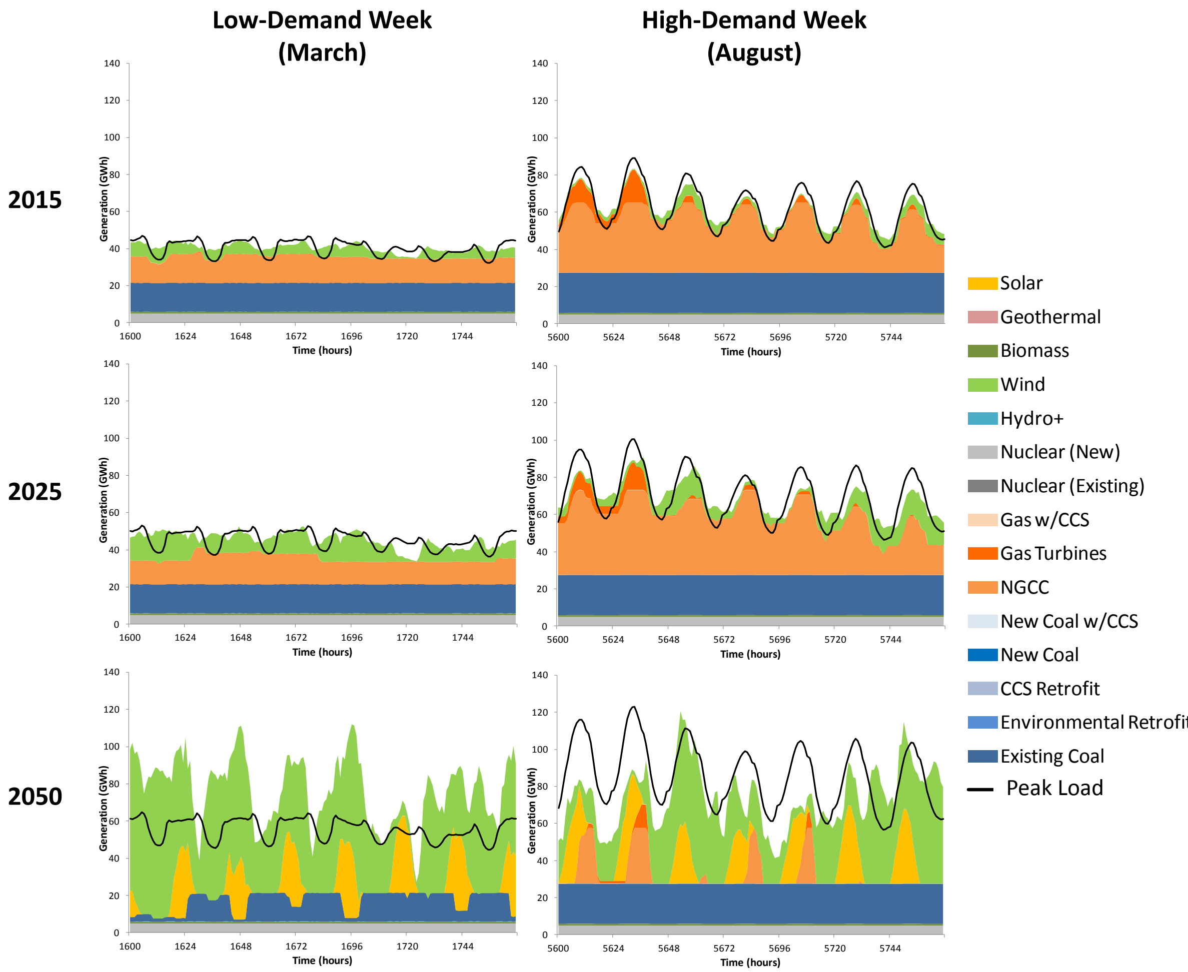


Figure 4-11
Weekly Dispatch-Texas Region by Year for High, Low Demand Weeks for Reference Scenario

Figure 4-12 shows the ramp duration curves over the course of the analysis year for each asset type. Hour-to-hour ramping behavior and volatility can be illustrated through ramp duration curves. The data are ordered such that the curves show the largest up ramps at left progressing the largest down ramps at right. Thus, the degree to which a curve shows greater slope suggests more ramping and greater ramp rates. The vertical axis provides information about the ramping magnitudes, and the horizontal axis provides information on the frequency distribution. Comparison of the 2015 and 2050 charts indicates that by 2050, imports and exports play a very significant role in supporting the region's ramping needs, and the ramping magnitude becomes larger for dispatchable generators even though the overall ramping frequency decreases.

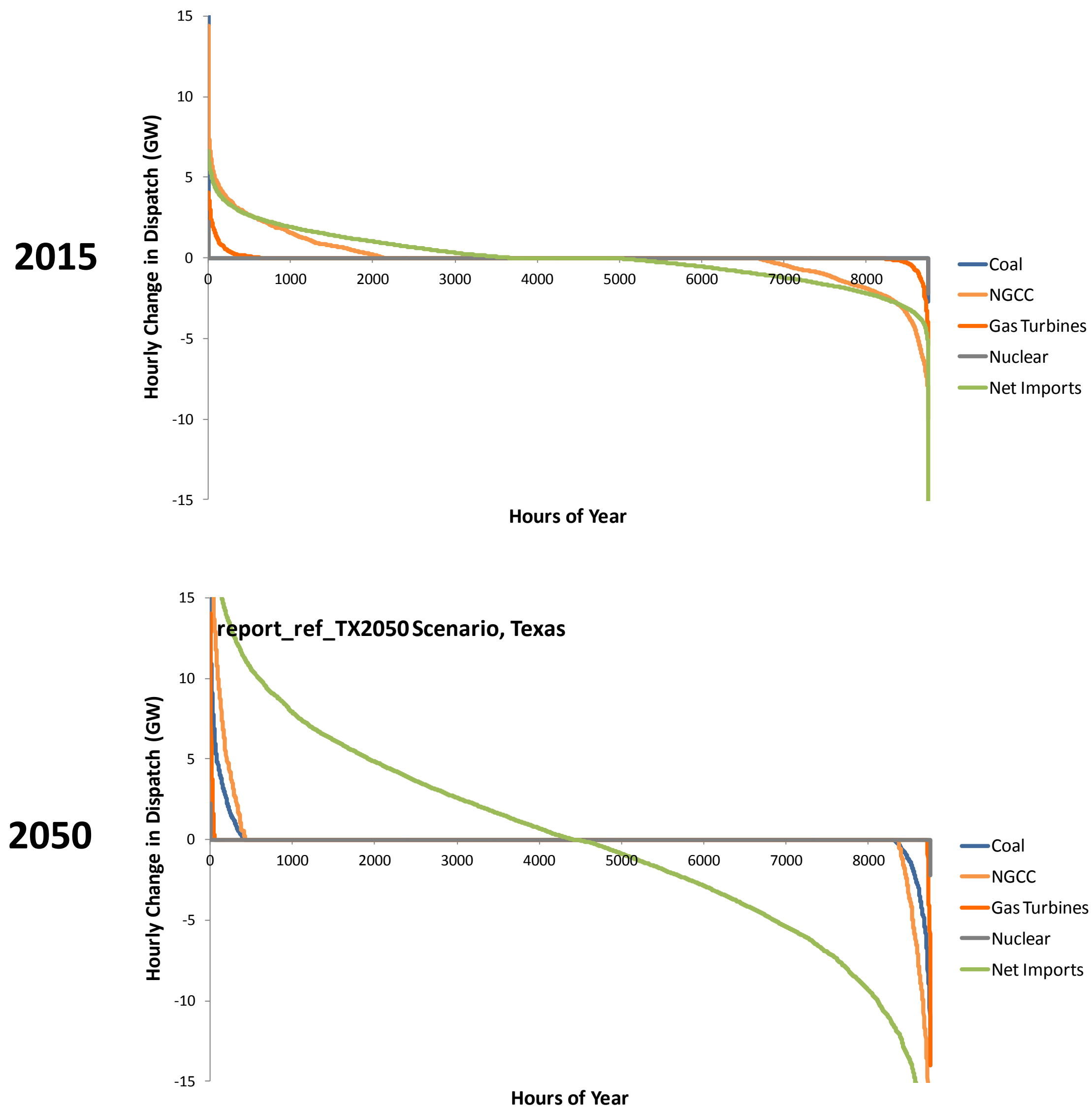


Figure 4-12
Sorted Hourly Ramp Duration Curves by Generation Type for Texas in 2015 and 2050

Figure 4-13 shows the ramp duration curves over the course of the analysis year for demand, variable generation, and net load ("net load" is the residual load remaining after variable generation is subtracted from in-region demand for each hour and designates electricity demand that must be met through dispatchable resources). Comparison of the 2015 and 2050 charts shows that net load matches the ramping associated with variable generation, which has increased substantially by 2050.

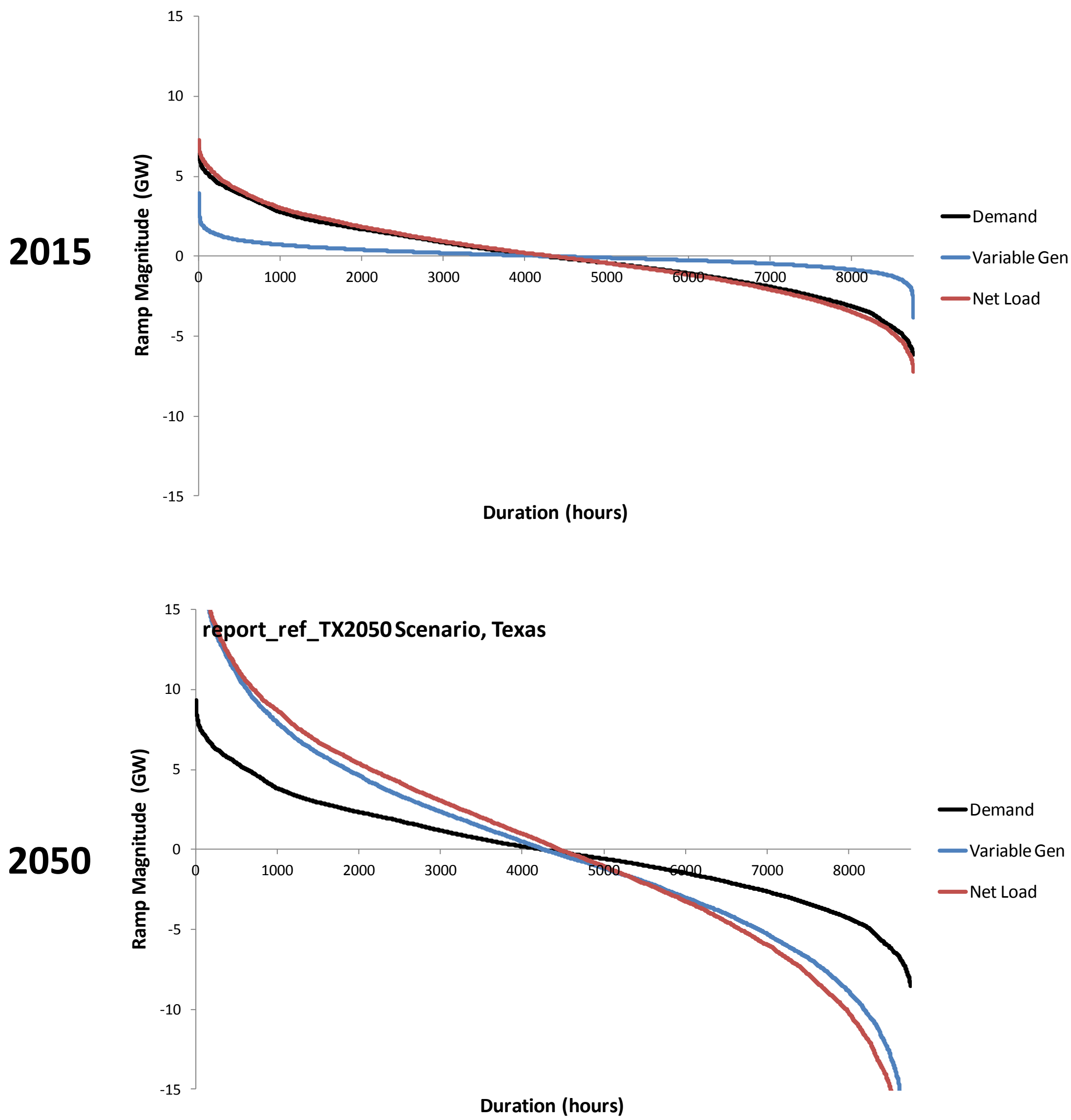


Figure 4-13
Sorted Hourly Ramp Duration Curves (Load, Net Load, Variable Generation): TX, 2015, 2050

Figures 4-14 and 4-15 show the high and low demand months for the region in 2025 for the four scenarios. These charts show that in the high gas price and high gas price/no new transmission scenarios, the increase in variability and the resulting effect on flexible operations for coal and combined cycles is very significant, particularly in the low demand month.

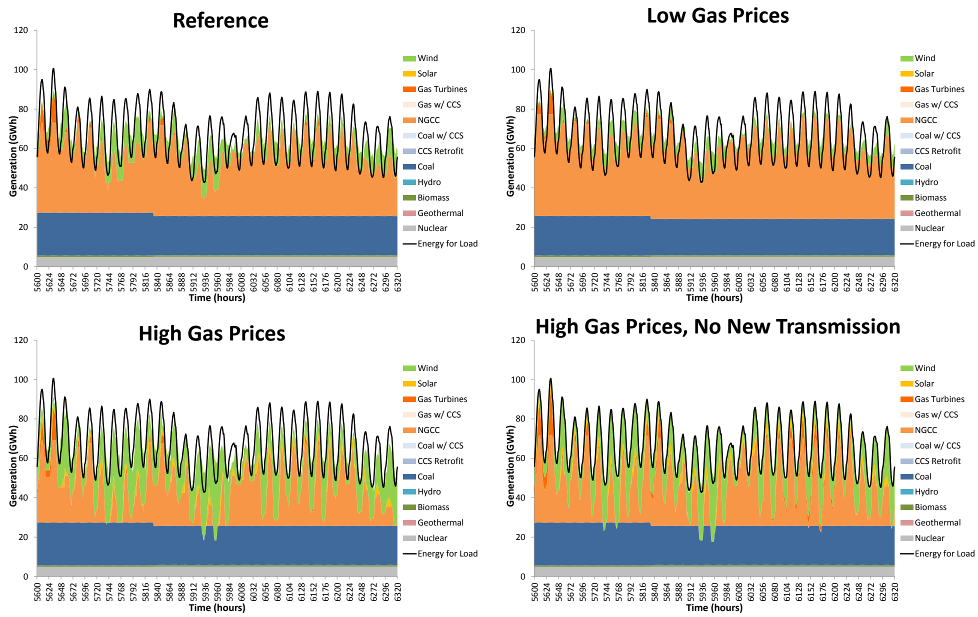


Figure 4-14
Monthly Dispatch (High-Demand Month, August) for Texas in 2025 for All Scenarios

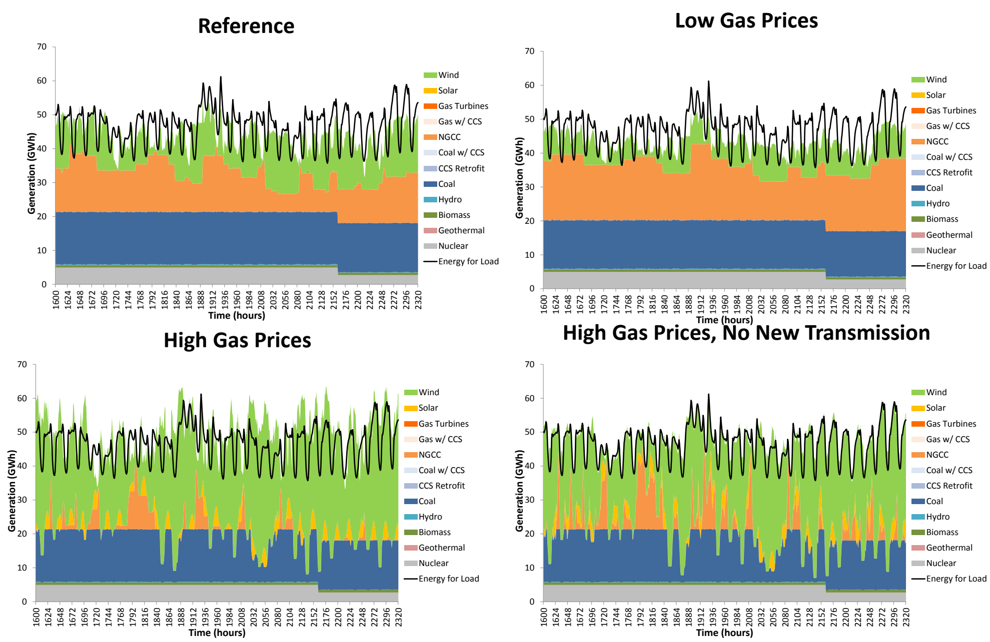


Figure 4-15
Monthly Dispatch (Low-Demand Month, March) for Texas in 2025 for All Scenarios

UC US-REGEN Results for Northwest Central

Figure 4-16 shows that for both the low and high demand weeks in a given year, variability significantly increases between 2015 and 2050. As in the case of the Texas region, by 2050, solar and wind generation shares have grown to a level such that their variability significantly affects the response from coal. For the low demand week, the coal assets have a number of periods of low output over a few hours. For the high demand week, a similar but more pronounced pattern is observed. Note also that in both the low and high demand weeks in 2050, wind generation significantly exceeds demand, thus implying likely exports from the region. Note also that while curtailment of renewables may occur, the amount of curtailment is not depicted on these charts.

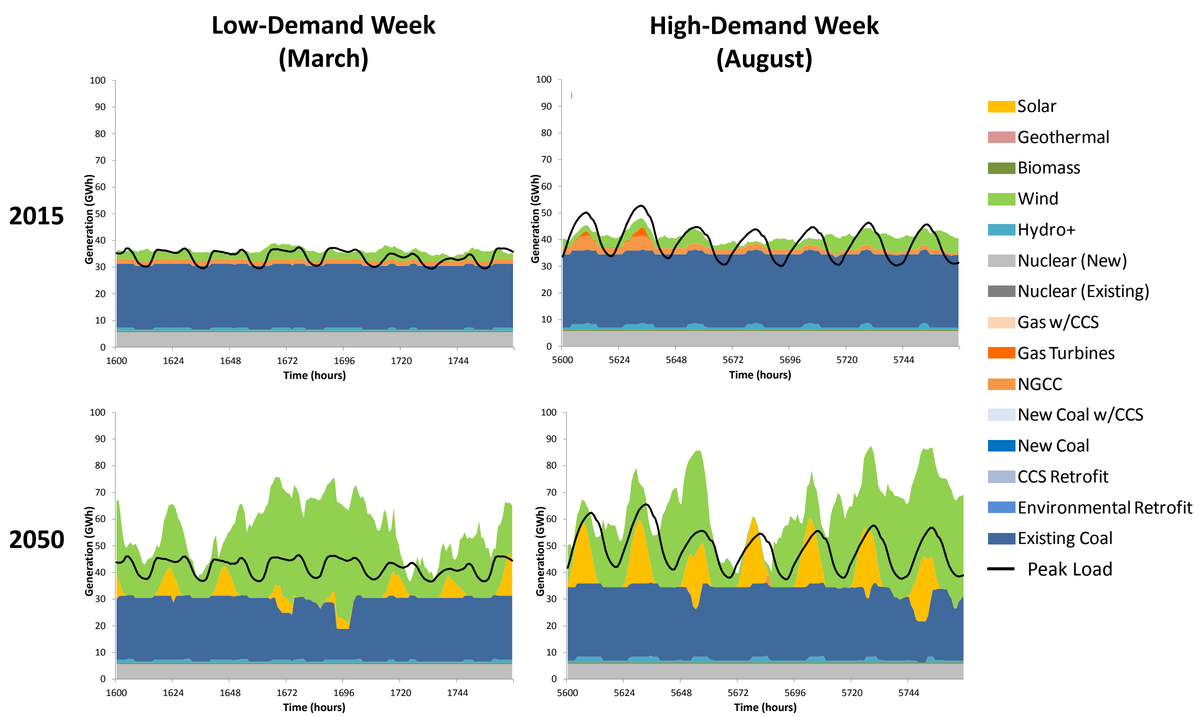


Figure 4-16
Weekly Dispatch-NW-Central Region for the Reference Scenario

Figure 4-17 shows the ramp duration curves over the course of the analysis year for each asset type. Hour-to-hour ramping behavior and volatility can be illustrated through ramp duration curves. The data are ordered such that the curves show the largest up ramps at left progressing the largest down ramps at right. Thus, the degree to which a curve shows greater slope suggests more ramping and greater ramp rates. The vertical axis provides information about the ramping magnitudes, and the horizontal axis provides information on the frequency distribution. Similar to what is observed in the Texas region, comparison of the 2015 and 2050 charts indicates that by 2050, imports and exports play a very significant role in supporting the region's ramping needs, and the ramping magnitude becomes larger for dispatchable generators even though the overall ramping frequency decreases.

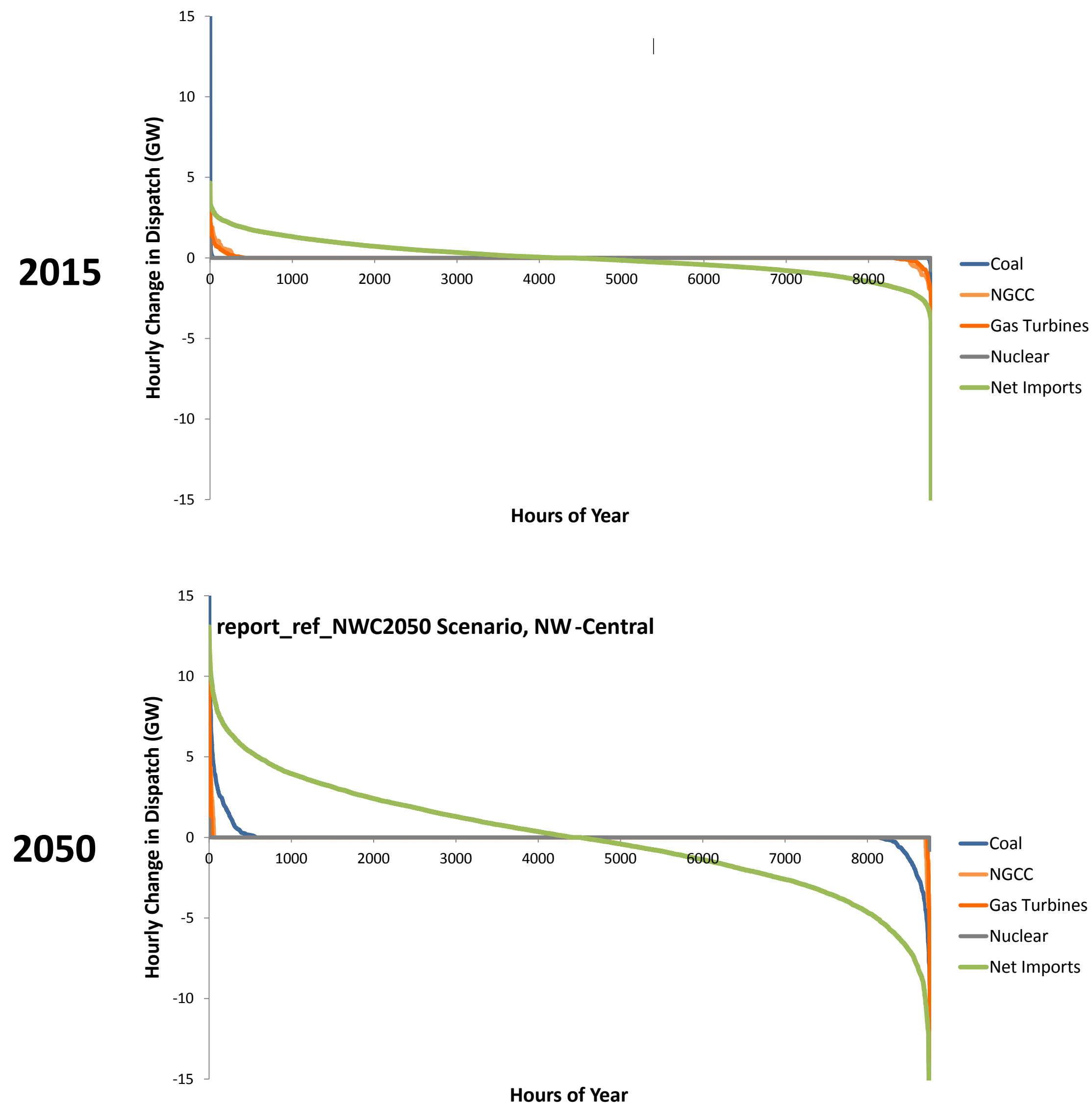
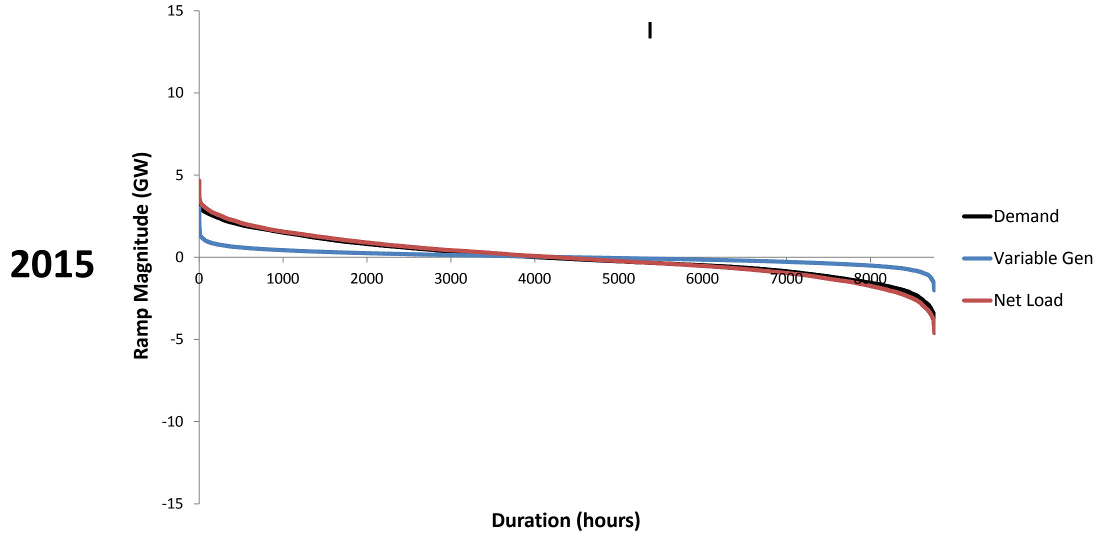


Figure 4-17
Sorted Hourly Ramp Duration Curves by Generation Type for NW Central in 2015 and 2050

Figure 4-18 shows the ramp duration curves over the course of the analysis year for demand, variable generation, and net load ("net load" is the residual load remaining after variable generation is subtracted from in-region demand for each hour and designates electricity demand that must be met through dispatchable resources). Comparison of the 2015 and 2050 charts shows that, although less pronounced than the Texas case, net load matches the ramping associated with variable generation, which has increased substantially by 2050.



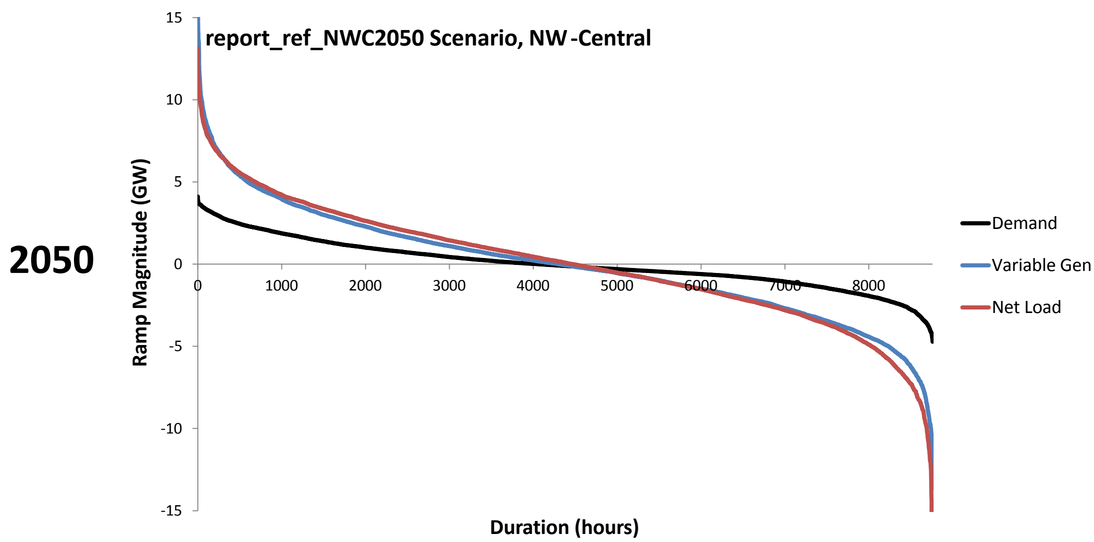


Figure 4-18
Sorted Hourly Ramp Duration Curves (Load, Net Load, Variable Gen): NW Central, 2015, 2050

Figures 4-19 and 4-20 show the high and low demand months for the region in 2025 for the four scenarios. These charts show that in the high gas price and high gas price/no new transmission scenarios, the increase in variability and the resulting effect on flexible operations for coal and combined cycles is very large. Given that coal is the principal dispatchable asset in NW Central, this increased level of flexible operations is particularly challenging (see further discussion later in this chapter).

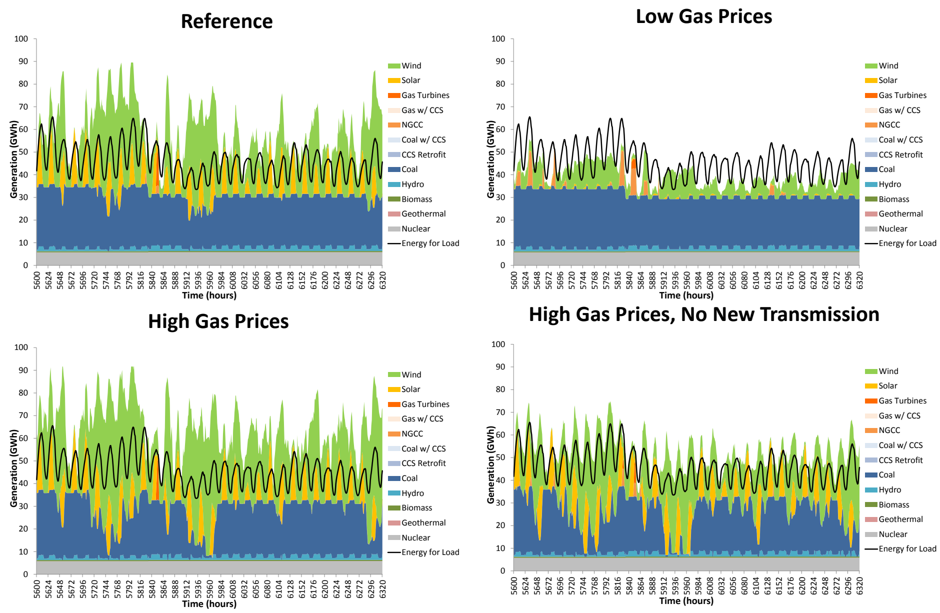


Figure 4-19
Monthly Dispatch (High-Demand Month, August) for NW-Central in 2025

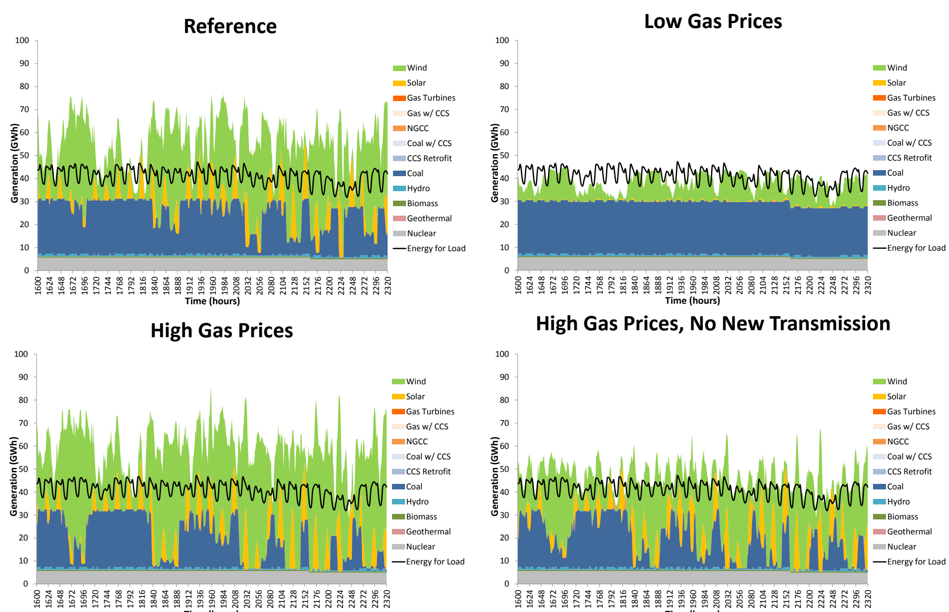


Figure 4-20
Monthly Dispatch (Low-Demand Month, March) for NW-Central in 2025

4.2.3 Engineering Assessment Results

As discussed in Section 3.3.5, the engineering assessment involved aggregating results from the unit commitment analyses by creating “heat maps” which permit a view of variation in hourly generation variability and capacity factor for different generation asset types. The comprehensive set of individual heat maps for generation variability and capacity factor are provided in Appendix C. Figures 4-21 and 4-22 present “mosaics” of the generation variability heat maps for the different scenarios for the natural gas combined cycle and coal generation asset types. These two asset types are presented here since they absorb the majority of flexible operations over time.

Recall that colors progressing toward yellow and red indicate increasing levels of flexible operations as indicated by increasing hour to hour variability in generation output during a given week. Blue indicates particularly high levels of variability. Each column of each individual heat map represents a week of the year, and each row represents one of the 15 regions.

The intent of these figures is to qualitatively show in a visual manner the substantial expansion of flexible operations projected over time and geography indicated by the analysis in this study. Several useful insights are apparent from this high level perspective:

- A majority of the increase in flexible operations occurs between 2025 and 2050. The increase in flexible operations is clearly very significant in 2050 across all scenarios and regions.
- As would be expected, natural gas combined cycle assets generally show more flexible operations in comparison to coal.
- Whether the unit commitment analysis detail region is Texas or Northwest Central, note that results for any given region are generally consistent across all regions and weeks.
- With a more coal-dominated fleet, the NW Central region generally exhibits greater demand for flexible operations across all scenarios.
- Scanning the heat maps horizontally (over time) or vertically (over regions) suggests that certain regions and weeks appear to experience relatively greater levels of flexible operations. This is discussed in further detail below.

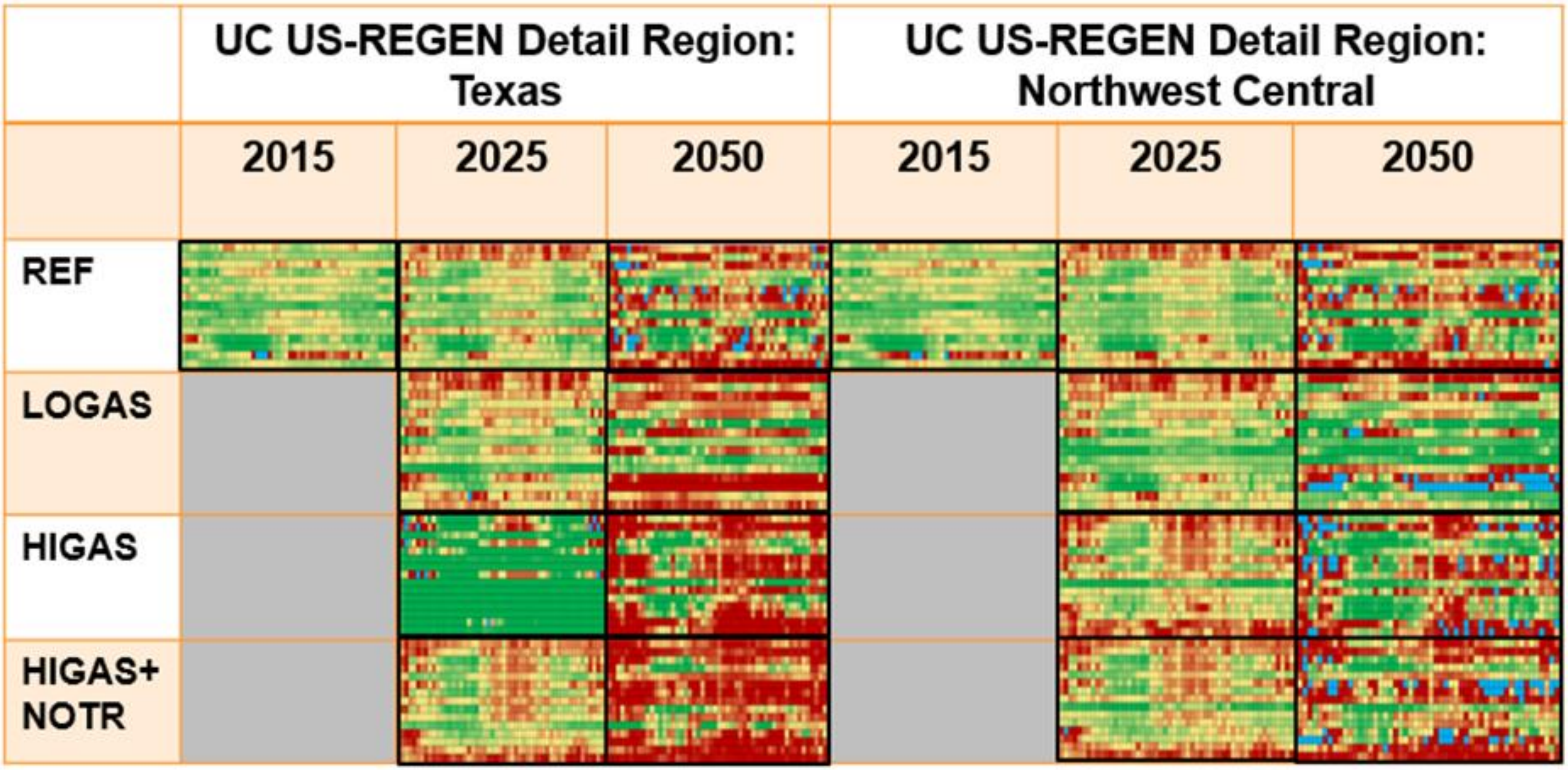


Figure 4-21
Heat Map "Mosaic" – Natural Gas Combined Cycle Assets

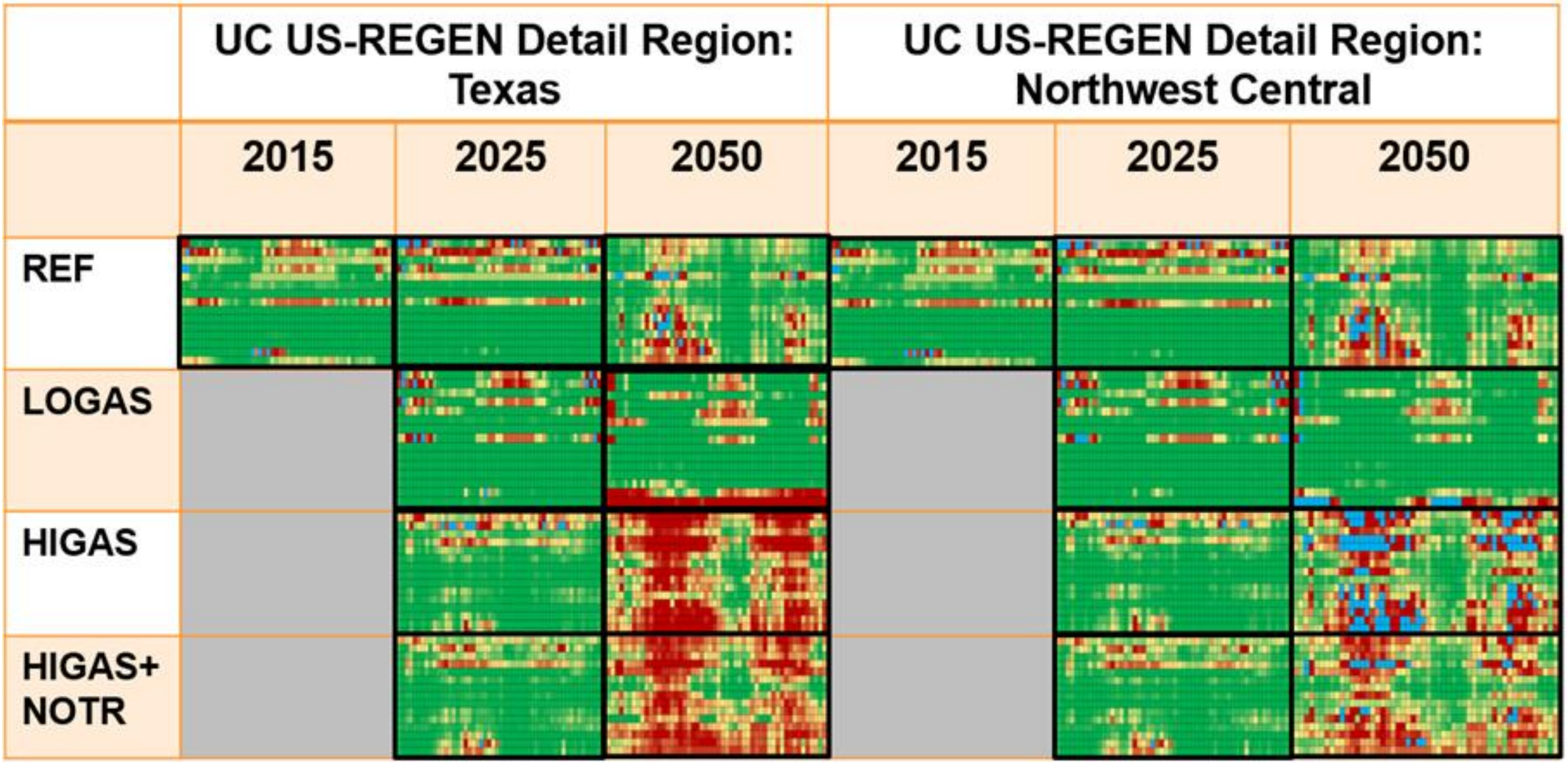


Figure 4-22
Heat Map "Mosaic" – Coal Assets

Table 4-6 presents the integrated assessment of the evaluations of the UC results across the four scenarios as described in Section 3.3.5 in the discussion under the subsection on *Aggregated Results from Engineering Assessment*. The table contrasts results of the assessment for 2050 and 2015, for both generation variability and capacity factor, for coal, NGCC, nuclear, and CTs, as well as for inter-regional imports. The numbers in the cell entries correspond to the colors to improve readability (4=red; 3=brown; 2=yellow; 1=green; 0 => no significant impact). In viewing these results, recall that in the discussion of the generation variability metric (section 3.3.5), even small reductions in the generation variability metric correspond to some significant flexible operations modes. Also note that for low capacity factors (which generally result in higher ratings for severity of flexible operations), several challenges exist: maintaining environmental controls system performance, maintenance of process temperature and pressure conditions while minimizing equipment damage, and reduced unit efficiency. Sustained low capacity factors may also suggest prolonged unit layup.

Considering the above comments, a number of key observations derive from Table 4-6:

- A degree of flexible operations are already present in 2015:
  - For coal (both in terms of generation variability and capacity factor) in the East super-region for all but the summer season.
  - For combustion turbine combine cycle units (CTCCs) in terms of lower capacity factors in the West and West Central super-regions in the spring and summer seasons.
  - For reliance in imports/exports from the West Central super-region in the summer and fall seasons.
- Examination of results for 2050 illustrates the profound growth in flexible operations in response to a generation mix with much higher shares of variable generation from renewables:
  - Coal experiences significant changes in generation variability in all regions other than the East Central super-region and in all but the summer season. Levels of severity are rated medium or high in most cases.
  - CTCC units experience severe levels of flexible operations in the majority of super-regions and seasons. Half of the super-region/season blocks are rated as having high or medium impacts with regard to capacity factor, and 1/3 of the blocks are rated high or medium impact with regard to generation variability. In addition to the technical challenges associated with significant flexible operations, increasing reliance on CTCC units as baseload assets could further limit their operational flexibility.
  - Significantly increased reliance on import/export of flexible generation occurs in 11 of the 16 super-region/season blocks. The summer season in the East super-region stands out.

Table 4-6
Integrated Results of Engineering Assessment

	2015	Coal	Capacity Factor	
	WINTER	SPRING	SUMMER	FALL
East	2	2	0	2
East Central	0	0	0	0
West Central	0	0	0	0
West	0	0	0	0

	2050	Coal	Capacity Factor	
	WINTER	SPRING	SUMMER	FALL
East	0	0	0	0
East Central	0	0	0	0
West Central	0	0	0	0
West	0	0	0	0

	2015	Coal	Gen Variability	
	WINTER	SPRING	SUMMER	FALL
East	1	0	1	0
East Central	0	0	0	0
West Central	0	0	0	0
West	0	0	0	0

	2050	Coal	Gen Variability	
	WINTER	SPRING	SUMMER	FALL
East	0	3	0	2
East Central	0	0	0	0
West Central	0	3	0	0
West	4	0	0	0

	2015	NGCC	Capacity Factor	
	WINTER	SPRING	SUMMER	FALL
East	0	0	0	0
East Central	0	0	0	0
West Central	0	1	0	0
West	0	0	1	0

	2050	NGCC	Capacity Factor	
	WINTER	SPRING	SUMMER	FALL
East	2	4	4	2
East Central	0	4	0	4
West Central	4	4	2	4
West	0	3	1	2

	2015	NGCC	Gen Variability	
	WINTER	SPRING	SUMMER	FALL
East	0	0	0	0
East Central	0	0	0	0
West Central	0	0	0	0
West	0	0	0	0

	2050	NGCC	Gen Variability	
	WINTER	SPRING	SUMMER	FALL
East	4	2	0	0
East Central	4	2	3	4
West Central	0	0	0	0
West	4	0	4	2

	2015	Nuclear	Capacity Factor	
	WINTER	SPRING	SUMMER	FALL
East	0	0	0	0
East Central	0	0	0	0
West Central	0	0	0	0
West	0	0	0	0

	2050	Nuclear	Capacity Factor	
	WINTER	SPRING	SUMMER	FALL
East	0	0	0	0
East Central	0	0	0	0
West Central	0	0	0	0
West	0	0	0	0

	2015	Nuclear	Gen Variability	
	WINTER	SPRING	SUMMER	FALL
East	0	0	0	0
East Central	0	0	0	0
West Central	0	0	0	0
West	0	0	0	0

	2050	Nuclear	Gen Variability	
	WINTER	SPRING	SUMMER	FALL
East	0	0	0	0
East Central	0	0	0	0
West Central	0	1	0	0
West	0	0	0	0

	2015	CT	Capacity Factor	
	WINTER	SPRING	SUMMER	FALL
East	2	2	2	2
East Central	2	2	2	2
West Central	2	2	2	2
West	2	2	2	2

	2050	CT	Capacity Factor	
	WINTER	SPRING	SUMMER	FALL
East	4	4	3	4
East Central	3	4	3	4
West Central	4	4	3	4
West	3	4	3	3

	2015	CT	Gen Variability	
	WINTER	SPRING	SUMMER	FALL
East	0	0	0	0
East Central	0	0	0	0
West Central	0	0	0	0
West	0	0	0	0

	2050	CT	Gen Variability	
	WINTER	SPRING	SUMMER	FALL
East	0	0	0	0
East Central	0	0	0	0
West Central	0	0	0	0
West	0	0	0	0

	2015	Imports	Gen Variability	
	WINTER	SPRING	SUMMER	FALL
East	0	0	0	0
East Central	0	0	0	0
West Central	0	0	2	1
West	0	0	0	0

	2050	Imports	Gen Variability	
	WINTER	SPRING	SUMMER	FALL
East	2	2	3	2
East Central	0	0	0	0
West Central	2	2	2	2
West	0	2	2	2

As part of the evaluation and aggregation of heat map results discussed above, certain regions and time periods exhibited particularly high and sustained levels of flexible operations in 2050. Tables 4-7 and 4-8 summarize those regions and time periods of particular note. The numerical values in these tables indicated the number of high ratings associated with either metric (generation variability or capacity factor) across the entire year for a given region, and across all regions for a given week. Only regions and weeks with significant numbers of high ratings were included; highlighted entries identify the regions and weeks with the highest impacts. Table 4-7 suggests that the Texas, Mountain South, Mountain North, South Atlantic, New England and West North Central regions have particularly high future levels of flexible operations over much of the year. It is interesting to note that different combinations of high ratings for each metric can drive the overall result; some regions are driven by lower capacity factor operations while others are driven by high levels of generation variability. Table 4-8 clearly identifies the spring season as the most stressed in terms of requiring high levels of flexible operations across most regions. This is well-known from experience, which helps to validate this approach.

Beyond demonstrating that future levels of flexible operations are likely to be very significant, with the concurrent technical challenges, there are several other considerations that impact the likelihood of the generation fleet to transform such that flexible operations capabilities will increase and remain:

- While this analysis views the generation fleet in each region holistically and assesses the economically optimum generation mix, the reality is that capacity planning is performed at the power company level and is motivated by business factors unique to each company. Therefore the generation fleet in a given region may inadvertently evolve in a manner that could potentially limit or even reduce operational flexibility.
- Relative to existing assets, changing economic and regulatory conditions lead to an ongoing assessment regarding whether to retire, invest to achieve operations to a specific future retirement date, or to invest to maintain long-term operations. These assessments are typically driven by an evaluation of the individual unit's economic and operational viability. As this study makes clear, flexible operations capabilities for the overall generation fleet are a complex function of the generation mix and ability to transfer energy via the transmission system. Unit-specific investment decisions for existing assets may collectively inadvertently lead to outcomes that adversely affect future fleet flexible operations capabilities.

Generally, the vast majority of the existing fleet was designed for operation at a specific output level. Unit operations across a range of different flexible operations modes places a significant challenge on power station staffs. A well-developed procedural basis and training program addressing the full range of different flexible operations modes generally have yet to be developed at most power companies. Combined with staff turnover and shrinkage at power plants driven by an aging workforce, supporting a much higher level of flexible operations across a large fraction of the dispatchable generation assets will present a significant challenge and may slow down the pace at which flexible operations can be adopted.

Table 4-7
Assessment of Particularly Affected Regions

Region	Weeks with Significant Levels of Generation Variability	Weeks with Significant Levels of Capacity Factor Variability	Total Weeks with High Variability
New England	8	4	12
New York	4	2	6
Mid -Atlantic	2		2
South-Atlantic	4	9	13
Florida	3	5	8
East North Central	6		6
East South Central	1	2	3
West North Central	3	8	11
West South Central	4	4	8
Texas	9	9	18
Mountain North	5	8	13
Mountain South	8	7	15
Pacific	6		6
California	5	1	6

Table 4-8
Assessment of Particularly Affected Weeks

Week(s)		*Gen Variability*	*Capacity Factor*	*aggregate score*
12	*Spring*	0	10	10
13		3	11	14
14		3	12	15
15		3	12	15
16		3	11	14
17		2	12	14
18		3	9	12
19		4	8	12
20		4	2	6
30	*Summer*	3	2	5
31		3	2	5
32		3	2	5
33		3	2	5
43	*Fall*	0	4	4
44		2	4	6
45		2	5	7
46		1	5	6
47		1	5	6
48		0	4	4

Review of Results by EPRI Subject Matter Experts

As noted above, a review of the project and its results was conducted with a group of EPRI subject matter experts (SMEs) with expertise in both coal and gas units relative to several key technical areas affected by flexible operations (e.g. process chemistry, turbo-machinery, gas turbines, boilers, heat recovery steam generators, power plant operations, maintenance, instrumentation & controls). The SME review focused on the following aspects of the project approach and results:

- Modeling assumptions
- Model results interpretation
- O&M impact of projected future operation
- Plant equipment impacts
- Critical design attributes of future plant equipment

In essence, the SME's concurred with the overall conclusions of the engineering assessment, but several more detailed observations were made regarding technical challenges and future research needs. These observations were organized into comments relating to the following aspects of the study:

- Assumptions and methodology
- Future analysis
- Interpreting results
- O&M impacts
- Equipment impacts
- Future plant design

Collectively, the SME comments suggest additional concerns regarding the feasibility of very high levels of operational flexibility (barring new technology capabilities). Some particularly key points:

- CTCC unit lifetimes are uncertain given relatively limited current experience with HRSGs and the impact of sustained operations at higher capacity factors.
- Water availability and gas pipeline access may prove to be additional externalities that limit new asset deployment and/or reduce operational flexibility.
- The ranges of CTCC ramp rates in practice today are more limited than assumed in this study.
- Availability of units to operate at low capacity factors or to operate between periods of prolonged layup may in reality be more limited if asset owners opt to retire rather than operate.
- The assumption of existing coal assets being available through 2050 may be questionable from perspective of the feasibility of late-life capital investments that will be necessary to maintain availability and efficiency under increased flexible operations.

Table 4-9 summarizes more detailed feedback from the SME review:

Table 4-9
SME Review Comments

Topic	Feedback
Assumptions and Methodology	• Nuclear plants could potentially flex, but ramp should be limited (i.e. <30% of max output/hr). • 100%/hr. is too high ramp rate for CTCC (from offline to online). • More limited lifetimes for CTCCs should be considered based on fact that HRSGs typically designed for 20-25 years.
Future Analysis	• Should treat cold, warm, hot starts differently re: ramp rates, shut down/start up times • Consider including tilted, bi-axial tracking solar technology in future analyses. • Consider modeling energy storage in future analyses. • Should include must-run units regionally. • Consider including intra-region transmission expansion constraints? • Include modeling of mid/late life one-time capital investments necessary to address aging issues, including accelerated aging due to cycling • Model determination of unit economic viability should include fixed & variable O&M cost increases resulting from cycling. • Should investigate scenarios where insufficient capacity is available. • Should future modeling include an "integrated" advanced, flexible CTCC where the BOP is able to match the flexibility of the advanced gas turbine? • Is there a benefit to modeling increased hydro flexibility? • Should overlay/compare other key resource maps to regionalization used in US-REGEN: – Water availability – Population growth – CO_2 storage availability – Gas pipeline infrastructure • Consider using cumulative number of on/off cycles by unit to estimate life-consumption. • Consider evaluating examination of heat maps and super-region results to see how flexibility challenge manifests in relation to unregulated markets. • Should ideally extract total fired hours from model, compare to recommended code limits, determine unit retirement based on this comparison. • Need to assess/define flexibility needs at system level, not just unit by unit.

Table 4-9 (continued)
SME Review Comments

Topic	Feedback
Interpreting Results	• If gas prices remain low, there could be a potential shift of cycling burden on to coal units. • Low capacity factors, in practice, may not be realized because in reality, asset owners will simply choose not to operate or to retire. • Recognize that effective "capacity market" modeled in US-REGEN is a simplification of the real markets, so availability of necessary capacity to support grid security isn't guaranteed. Recognize that mechanisms to incent new resources vary significantly across different markets. • Assumption of existing coal plant operations through 2050 is questionable, considering necessary capital investments to sustain high capacity factors, safety concerns, shortened lifetime due to prolonged cycling operations. • Economic basis of assumed 80 year nuclear lifetime for 80% of fleet is uncertain. From technical perspective, potential limiting factors to 80 yr. life may be BOP, e.g. cable replacement • Recognize that, if allowed, nuclear flexibility would likely not be frequent and dynamic load changes, but rather reducing output to a defined level to "make room" for other assets under certain conditions where that is economically or operationally desirable for the grid. • At some point, long-term layup may practically mean permanent retirement (considering damage and capital necessary to return to service, unavailability of staffing, etc.) • Increased risk of "self-retirement", i.e. failure of a sufficiently major component that retirement rather than repair/replacement is best option
O&M Impacts	• Need new O&M strategies associated with low capacity factor (CF) operations for multiple train systems. • Safety concerns introduced by infrequent/first of a kind evolutions driven by low CF operations – related issue is meeting this challenge with inexperienced staff. • Operational/training not "tuned" for flexible operations. • I&C also not "tuned/optimized" for flexible operations. • Flexible operations potentially creates process chemistry imbalances/effects. • Staff availability/staffing strategies, availability of necessary experienced workers. • Increased seasonal variability in plant staffing requirements will change old paradigm of dedicated plant staff.
Equipment Impacts	• Thermal fatigue of major components is the key driver of damage due to ramping and frequent starts • Creep-fatigue interaction will become an increasingly important damage mechanism when aging units are forced to operate flexibly. • Flexible operations can create potential for short term overheating; not a long-term effect, but potentially affects availability because of associated increase in thermal fatigue damage.

Table 4-9 (continued)
SME Review Comments

Topic	Feedback
Future Plant Design	• Optimizing I&C for flexible operations. – Sensors and controls to support real time information, i.e. monitoring more and different parameters, associated diagnostics – Note that measurands may now include "indirect" data, e.g. a measurand + a model = virtual data – Automation to compensate for smaller, less experienced staff and reduce human error – Prognostics capabilities & models informing/giving time to failure for components; implication is ability to better anticipate, modify operations to mitigate • Optimizing maintenance for flexible operations. – need to design units to facilitate measurement, monitoring, accessibility of systems & components that will require different/additional maintenance and inspection as a result of flexible operations. • Need alternative NO_x control technologies (to SCR) which are more flexible and viable for both coal and gas. • Build in characteristics that enable “buffering” between plant and flexible demand, e.g. energy storage systems of various sorts capturing portion of plant output. – Greater use of steam bypass (i.e. trading efficiency, equipment damage for flexibility) – Place bypass downstream of HRSG to permit maintenance of HRSG process conditions to minimize damage, yet enable flexible operations – Explore flexible uses for heat in combined heat and power (CHP) applications • Need to develop/deploy advanced materials (e.g. AUSC materials) to have components with smaller thermal gradients (i.e. smaller component/piping wall thickness) and therefore lower stress cycles • Standardization would significantly mitigate issues related to limited and less available staffing, associated issues associated w/training, procedures. – Also positively affects instrumentation, control design • Need to design units to cost-effectively plan/enable prolonged layup and associated necessary protective measures. • Increasing limitations on water availability, if they result in more assets that are air or hybrid cooled, could have multiple consequences: – Less operational flexibility in summer => may require more design capability/margin to achieve – Increased needs for layup protection measures for dry/hybrid cooling systems • Need to address heat rate improvement at lower loads, e.g. adding variable frequency drives, etc. • Automated control of ramp rates could help ensure acceptable ramp rate practices.

Engineering Conclusions

The engineering assessment of the model results shows that the scope of increased, severe flexible operations is very likely to be extensive by 2050, affecting a large fraction of the dispatchable assets in most regions throughout most of the year, across a range of different scenarios. Much of the increased flexible operations occurs after 2025 as the generation share of renewables significantly increases. Coal and CTCC units take on the majority of the flexible operations burden, particularly CTCC units, but there is also a strong reliance on significant inter-regional energy transfers if the transmission system can expand substantially. Note that the remaining coal in the fleet is almost entirely existing units with environmental controls retrofits that will be quite old by 2050 (i.e. on average>75 years old.) As has been noted in several other studies, transmission capacity is a critical resource in systems with large renewable generation shares.

Several technical concerns arise regarding the feasibility of supporting such widespread and severe flexible operations; most of these concerns relate to whether enough assets will be available in the future for the expected level of flexible operations:

- Asset availability for low load and cycling operations is not assured when considering how capacity planning and individual unit investment decisions are made. The potential for absence of strong markets incenting investment and development of flexibly operating assets casts further doubt on achieving the necessary level of flexible operations across a large fraction of the fleet.
- Asset operational lifetimes are uncertain when considering equipment damage effects, adverse impacts on environmental controls performance and unit heat rates, and emerging challenges around assuring adequately trained staff in the future to operate units in flexible modes.
- External factors such as water availability for thermal plants and gas pipeline access for CTCCs may limit flexible operations and delay development of new assets.

It will therefore be likely that significantly improved technology capabilities and operations practices will be needed to enable the future generation fleet to provide the levels of flexible operations indicated in this study.

4.3 Overall Conclusions

This study focused on evaluating the long-term implications of significantly increased levels of variable generation and uncertain natural gas prices on the composition and operability of the future generation fleet in the United States. This goal was achieved by focusing on the degree to which flexible operations are required as the share in renewable energy generation increases. The study adopted a different perspective than typically seen in past studies, i.e. a detailed examination of the engineering feasibility of the level of flexible operations in future generation fleets.

The study approach also integrated two key elements of analysis rarely brought together in a single analysis: long-term capacity planning, which enables modeling of unit retirements and new asset investments, and unit commitment analysis, which permits examination of hourly unit dispatch while considering operational limitations relevant to flexible operations capabilities.

EPRI's energy-economics analysis platform, US-REGEN, was used, allowing treatment of the US electric sector in terms of 15 different regions and their interconnection via the transmission network. Four scenarios were evaluated: a reference scenario and three scenarios based on low or high natural gas price trajectories and the potential for future transmission expansion. Based on these scenarios, unit commitment analysis for two future years, 2025 and 2050, of the future generation fleet allowed an evaluation of which assets are experiencing significant flexible operations on a regional and temporal basis. Detailed examination of these results in terms of observed hourly variability in generation and unit capacity factors permitted a detailed assessment of future levels of flexible operations on a regional basis.

Review of nearly 50 studies and papers confirmed that flexible operations are the principal challenge arising from increased variable generation, and that key challenges are operations at minimum loads and significant amounts of ramping at high rates. Many of these studies also confirmed the importance of increasing levels of transmission capacity to enabling fleet-wide flexible operations. However, very few prior studies have focused in depth on the long-term engineering and operational challenges associated with high, sustained levels of flexible operations.

Driven by existing regulatory policies (including renewable portfolio standards) and fuel prices, significant levels of renewable (excluding hydro) electricity generation (i.e. 11-41% of total generation) emerge by 2050. Despite variations in the generation technology mix in different regions, widespread high levels of flexible operations are observed across most regions for much of the year by 2050. Frequent, large changes in average hourly generation are observed for combustion turbine combined cycle and coal assets, as well as significant periods of low load operations. The extent and severity of expected levels of flexible operations in terms of average hourly generation variability for natural gas combined cycle and coal is likely to be very, very challenging (see Figures 4-21 and 4-22). For nearly all scenarios, 2050 shows particularly significant levels of flexible operations in several specific regions and during the spring season generally.

Achieving these levels of flexible operations on such a widespread basis will present several significant technical challenges and is also subject to important external factors that could impede development of fleet flexible operations capabilities. This analysis was based on technical assumptions about operational lifetimes for different asset types and assumes strategic fleet management leading to an economically optimum generation mix. In reality, unit lifetimes for coal and CTCC assets could be significantly shorter based on cumulative damage effects due to sustained flexible operations combined with reluctance by asset owners to invest in units if they are not seen as individually economically viable. External factors such as natural gas prices, potential future limitations on water availability and access to natural gas pipelines could limit how new assets are added to the fleet such that flexible operations capabilities are increased.

In summary, the feasibility of achieving the very high levels of operational flexibility across a majority of the generation fleet as shown in this study is highly uncertain without additional technical capabilities enabling increased flexible operations, expanded inter-regional transmission capacity, and economic drivers causing asset owners to invest in creating increased unit flexibility.

5
NEXT STEPS FOR RESEARCH

The complexity of flexible operations, how they impact unit reliability and availability and thus long-term fleet capabilities, and modeling capabilities combine to create many technical questions requiring additional research. The research performed in this project led to the identification of several key opportunities to significantly improve understanding of how the generation fleet may need to respond to increased sources of variability, e.g. renewable energy generation, demand response, distributed resources, and consumer management of loads.

Specific additional research opportunities are organized below in terms of additional engineering analysis and improvements to modeling. Most of these recommendations could be implemented within the framework of the approach taken in this study, using the US-REGEN analysis platform. Much more research is needed to adequately understand flexible operations at the asset level and how to provide those capabilities on an economically sustainable, long-term basis for the entire generating fleet.

Next Steps: Engineering Analysis

- Perform parametric analyses for engineering parameters identified by the SMEs (e.g., ramp rates, turndown limits, NGCC lifetime).
- Perform sensitivity studies to quantify the value of new technical capabilities (postulated based on ongoing research) to improve operational flexibility capabilities (e.g., more rapid cycling of existing coal and gas assets, lower turndown limits)
- Analyze impact of late-life singular capital investments to maintain/extend unit life in response to cumulative cycling damage.
- Investigate whether strategies to mitigate the reduction in economic value of renewables at higher penetration levels (e.g., real-time pricing, energy storage, increased spatial diversity of renewables) may also mitigate problems associated with operational constraints of conventional generators
- Extend analysis and examination of heat maps and super-region results to see how flexibility challenge manifests in relation to unregulated markets.
- Need to assess/define flexibility needs at system level, not just unit by unit.
- Develop/apply criteria for judging future economic viability via review of US-REGEN results of low capacity factor units in situations where the capacity market is not fully developed.

Next Steps: Modeling

- Improved modeling
    - Fully integrate the capacity planning and unit commitment problems (i.e., endogenous treatment of both dispatch and investment including wear-and-tear costs).
    - Modify the unit commitment model (UC US-REGEN) to allow unit-level analysis in multiple regions simultaneously, thus allowing modeling of full effects of potential limitations in inter-regional energy import/export through consideration of operational flexibility limitations for all units in all regions simultaneously
    - Capture uncertainty in the unit commitment model (i.e. model uncertainty in the quality of renewable resources.)
    - Examine sub-hourly impacts in the unit commitment model.
    - Incorporate price-responsive demand into the unit commitment model to understand its potential role in improving system operation and cost outcomes.
    - Include option to limit intra-region transmission expansion.
    - Include (i.e. make endogenous) fixed & variable O&M cost increases resulting from cycling in model determination of unit economic viability.
    - Model external constraints for new asset development related to geographical limitations in water availability, CO2 storage site access, and gas pipeline access.
    - Model asset life as a function of cumulative on/off cycles, total fired hours, based on ASME code recommendations.
    - Develop modeling approach to analysis of potential limitations on gas asset investment/deployment due to limitations on gas pipeline availability/cost.

- Including additional technology characteristics, capabilities in modeling
    - Model energy storage in the unit commitment model.
    - Model the value of demand response as a substitute for fast-ramping capacity in the unit commitment model.
    - Model cold, warm, hot starts differently re: ramp rates, shut down/start up times
    - Consider including new generation technology options (e.g. integrated, advanced, flexible CTCC units, bi-axial solar tracking technology)
    - Model must-run units by region.
    - Model potential hydro flexible operations.

- Additional Scenarios
    - Conduct a comparison of results for a defined set of scenarios with different models to investigate sensitivity of conclusions to modeling approach.
    - Model a scenario in which 50% CCS is available immediately or in 2020 with 90% CCS available in 2025.

A
CORE DATA FOR THE US-REGEN ELECTRIC SECTOR MODEL

This appendix lists general data and policy assumptions for the dynamic US-REGEN model. All costs are listed in constant 2009 dollars. Refer to the complete US-REGEN documentation (EPRI 2014) for additional detail about model assumptions and structure.

Table A-1
Time Varying Technology Parameters for New Generation Capacity

Technology	Installation Year	Capital Cost (2009$/kW)	Heat Rate (MMBtu/MWh)
Supercritical Pulverized Coal (with full environmental controls and without CCS)	2015	2590	8.749
	2030	2590	7.935
	2050+	2590	7.582
Integrated Gasification Combined Cycle Coal (with full environmental controls and without CCS)	2015	3490	8.932
	2030	3050	7.582
	2050+	2870	6.963
IGCC Coal (with CCS) *(Not available until 2025)*	2020	4380	10.006
	2030	4040	8.726
	2050+	3800	7.667
IGCC Coal (with partial CCS) *(Not available until 2025)*	2020	4100	9.749
	2030	3780	8.492
	2050+	3560	7.520
Natural Gas Combined Cycle (without CCS)	2015	1160	6.893
	2030	1160	6.319
	2050+	1160	6.319
Natural Gas Combined Cycle (with CCS) *(Not available until 2025)*	2020	2280	7.403
	2030	2180	7.01
	2050+	2050	6.89
Natural Gas Turbine (without CCS)	2015	820	11.01
	2030	820	10.19
	2050+	820	9.75
Dedicated Biomass (based on a 50 MW direct fire plant)	2015	4610	12.875
	2030	4410	11.371
	2050+	4150	10.662

Table A-1 (continued)
Time Varying Technology Parameters for New Generation Capacity

Technology	Installation Year	Capital Cost (2009$/kW)	Heat Rate (MMBtu/MWh)
Nuclear	2015 2030 2050+	5620 5360 5050	10 10 10
Hydroelectric	2015 2030 2050+	2000 2000 2000	N/A
Geothermal	2015 2030 2050+	5560 5310 5000	N/A
Wind Power Onshore, *More Optimistic*	2015 2030 2050+	2090 1510 1510	N/A
Wind Power Onshore, *Reference*	2015 2030 2050+	2270 1770 1770	N/A
Wind Power Onshore, *Less Optimistic*	2015 2030 2050+	2440 2030 2030	N/A
Wind Power Offshore, *More Optimistic*	2015 2030 2050+	3140 2270 2010	N/A
Wind Power Offshore, *Reference*	2015 2030 2050+	3140 2460 2180	N/A
Wind Power Offshore, *Less Optimistic*	2015 2030 2050+	3140 2610 2310	N/A
Solar Photovoltaic (Central Station) *More Optimistic*	2015 2030 2050+	1830 1160 1010	N/A
Solar Photovoltaic (Rooftop) *Reference*	2015 2030 2050+	3350 2290 2050	N/A
Solar Photovoltaic (Rooftop), *Less Optimistic*	2015 2030 2050+	3950 2840 2590	N/A

Table A-1 (continued)
Time Varying Technology Parameters for New Generation Capacity

Technology	Installation Year	Capital Cost (2009$/kW)	Heat Rate (MMBtu/MWh)
Concentrating Solar Power, *More Optimistic*	2015 2030 2050+	6480 4550 3340	N/A
Concentrating Solar Power, *Reference*	2015 2030 2050+	6480 5440 4660	N/A
Concentrating Solar Power, *Less Optimistic*	2015 2030 2050+	6480 5840 5340	N/A

Table A-2
Time-Independent Technology Parameters for New Generation Capacity

Technology	Fixed O&M Costs (2009$/kW-yr.)	Variable O&M Costs (2009$/MWh)	Plant Lifetime (years)
Supercritical Pulverized Coal (with full environmental controls and without CCS)	58	2.5	100
Integrated Gasification Combined Cycle Coal (with full environmental controls and without CCS)	105	2	60
IGCC Coal (with CCS)	134	3.4	60
IGCC Coal (with partial CCS)	119	3.1	60
Natural Gas Combined Cycle (without CCS)	14	2.4	100
Natural Gas Combined Cycle (with CCS)	26	5	60
Natural Gas Turbine (without CCS)	14	4.5	100
Dedicated Biomass (based on a 50 MW direct fire plant)	62	5	60
Nuclear	105	1.7	80
Hydroelectric	67	0	100
Geothermal	67	9.6	30
Wind Power Onshore	37	0	25
Wind Power Offshore	98	0	25
Solar Photovoltaic (Central Station)	21	0	30
Solar Photovoltaic (Rooftop)	21	0	30
CSP (Solar Thermal)	72	0	60

Table A-3
Cost and Performance Assumptions for Coal Retrofits

	Capital Cost (2009$/kW)	Change Relative to Base Coal Plant			
		Capacity Penalty	Heat rate	Non-CO2 emissions rates (SO_x/NO_x)	Variable O&M
Enable 10% Biomass Co-Fire	$20 (i.e. $200/kW of biomass capacity)	1.2	1.2	0.0/0.8	1.0
Convert to Gas	$150	1.0	0.96	0.0/0.05	0.5
Convert to 100% Biomass	$1,000	1.44	1.2	0.0/0.05	0.9
Convert to CCS (90% capture)	$1,500 for Non-Compliant classes; $750 or more for Compliant classes / Environmental Retrofit*	1.5	1.5	0.15/0.05	2.0
Environmental Retrofit	Varies by class up to $6,000	1.05	1.05	0.15/0.05	$4/MWh

* "Second-stage" CCS retrofit (i.e., for capacity that has already undertaken an environmental retrofit) is adjusted in some cases to ensure that the total cost of both retrofits is greater than $1,500, the cost of a "single-stage" CCS retrofit. Additionally, the cost of the single-stage retrofit declines slightly over time.

Table A-4
Policy and Other Generic Assumptions

Area	Assumption
Baseline Reference	• EIA Annual Energy Outlook (AEO) 2014 – Projected level of energy demand – Reference energy prices
Electric sector policies	• Renewables – Existing state RPS requirements – Production tax credit through 2020 • Environmental – Environmental controls required on existing coal units (MATS, cooling water, coal ash) – CAA Sec 111(b): No new coal units without CCS – No representation of CAA 111(d)
Nuclear	• New nuclear allowed • 80% of existing nuclear extended to 80 years • 6 GW constructed before 2020; maximum build rate = 7 GW/decade thereafter
Renewable Energy	• Cost reductions occur over time (due to assumed technology improvements)
Coal	• CCS (50% or 90%) retrofit available as of 2025 • CCS (50% or 90%) available for new units as of 2025
Transmission	• Historical growth rates

B
LITERATURE REVIEW RESULTS

Part of this project was to review relevant existing studies and reports which would inform the modeling and analysis efforts. The literature review was envisioned to provide insights regarding technical assumptions and inputs to the modeling effort. The scope of the literature review was structured to consist of two tasks:

- A review of interconnect and reliability studies, such as relevant NERC studies and regional interconnect studies. An expected outcome of these reviews was a better understanding of operational flexibility requirements that would inform modeling assumptions made later.
- A review of studies focused on existing experience with transformation in the generation fleet, such as impacts of increased flexible operations on costs and unit availability. An expected outcome of these reviews was a better understanding of operational impacts and O&M cost impacts resulting from flexible operations that would inform modeling assumptions made later.

Interconnect and Reliability Studies

The scope of the Task 3 literature review is summarized in Table B-1 below:

Table B-1
Interconnect and Reliability Study Literature Review Scope

1.	***Analysis of Cycling Impacts on Combined Cycle***, Lefton, S, et al, ASME Power Proceedings 2008
2.	***DOE: Integrating Southwest Power Pool Wind Energy into Southeast Electricity Markets***, October 2011, EPRI, DE-EE0001377
3.	***Eastern Interconnect Planning Collaborative (EIPC), Steady State Modeling and Load Flow Working Group, Report for 2018 and 2023 Roll-Up Integration Cases, Stakeholder Draft 1***, December 2013
4.	***Eastern Renewable Generation Integration Study***, November 2013, NREL Technical Review Committee, Bloom, Townsend, et al
5.	***Eastern Wind Integration and Transmission Study***, 2011 EnerNex, NREL/SR-5500-47078
6.	***ERCOT Presentation, EPRI Fossil Generation Assets and Power System Flexibility Workshop***, 2013, Surendran, Resmi
7.	***Flexible Coal: Evolution from Baseload to Peaking Plant***, December 2013, NREL/BR-6A20-60575
8.	***Hawaii Solar Integration Study***, NREL/TP-5500-57215, June 2013
9.	***Impacts of Wind and Solar on Fossil-Fueled Generators***, Lew, D., et al, IEEE Power and Energy Society General Meeting, NREL/CP-5500-53504, July 2012
10.	***Integrating Intermittent Renewable Energy Technologies with Coal-Fired Power Plant***, 2011, IEA Clean Coal Centre CCC/189
11.	***Investigating a Higher Renewables Portfolio Standard in California***, Executive Summary, Energy & Environmental Economics, Inc., January 2014
12.	***PJM Renewable Integration Study***, GE Energy Consulting, February 2014
13.	***Power System Flexibility Metrics: Framework, Software Tool and Case Study for Considering Power System Flexibility in Planning***, December 2013, EPRI 3002000331
14.	***Power System Operational and Planning Impacts of Generator Cycling due to Increased Penetration of Variable Generation***, December 2013, EPRI 3002000332
15.	***Resource Adequacy and Economic Impacts of Integrating Intermittent Resources***, November 2013, Astrapé Consulting
16.	***The Western Wind and Solar Integration Study Phase 2***, September 2013

1. ***Analysis of Cycling Impacts on Combined Cycle***; Lefton, et al; ASME Power Proceedings 2008

   Synopsis

   This paper, republished in the April 2009 issue of Energy-Tech Magazine, outlines APTECH's approach to developing cycling cost impacts for a given unit. The APTECH approach is a combination of a generic statistically-based top-down cost model, subsequently adjusted/augmented by unit-specific data analysis.

   Relevance to This Project

   APTECH is a key engineering consultant in this field and a key contributor to the WSIS Phase 2 study (reviewed separately in this report) as well as other NREL studies. To date, their approach has been a principal source of approaches to estimating increased O&M costs associated with cycling.

   Summary of Key Insights and/or Data

   - The report provided added detail and background on APTECH's methodology, thus helping with the review of the WSIS Phase 2 analysis results.

2. ***DOE: Integrating Southwest Power Pool Wind Energy into Southeast Electricity Markets***, October 2011, EPRI, DE-EE0001377

   Synopsis

   The goal of this project was to evaluate the benefits of coordinating scheduling and balancing for Southwest Power Pool (SPP) wind transfers to Southeastern Electric Reliability Council (SERC) balancing authorities. The project focused on benefits of different balancing approaches based on increasing levels of inter-regional cooperation. The study specifically looks at challenges associated with delivery of sufficient wind generation to meet a 20% RPS across the SPP, Southern Company, and Tennessee Valley Authority balancing areas for the year 2022.

   Relevance to This Project

   The report was of particular interest due to its focus on inter-regional cooperation, which is important in light of US-REGEN results which suggest significant inter-regional energy transfers in most scenarios.

   Summary of Key Insights and/or Data

   - The report looked at the impact of variability and uncertainty of wind generation for each scenario on reserve requirements (regulation, spinning reserve, and supplemental).
   - Although hurdle rates for transfers of energy between regions were considered, no constraints on transmission were applied. Based on analysis in the DOE FT project, transmission constraints are very important.
   - The aggregate regulating reserve requirement (based on transferring 48 GW of wind generation) is on the order of 40% larger than the baseline case (14 GW of wind).

- The aggregate spinning reserve requirement for the same two cases increases on the order of 50%.
- The report calculates a reduction in electricity production costs of roughly $4/MWh based on avoided fuel costs associated with a 34 GW increase in wind generation, but notes that certain related costs were not addressed: purchase cost of wind energy, capital or O&M costs associated with new wind capacity.
- Other key assumptions cited in the report:
  - Unconstrained transmission: thermal constraints were removed and losses ignored.
  - Although the analysis suggested a high sensitivity to gas price, only one set of future gas and carbon prices were used.
  - The analysis did not account for potential retirements of conventional generation concurrent with increasing wind generation, thus resulting in larger reserve margin than is likely in reality.
- The primary conclusion of the report is that there is significant benefit to inter-regional cooperation and coordination.

3. ***Eastern Interconnect Planning Collaborative (EIPC), Steady State Modeling and Load Flow Working Group, Report for 2018 and 2023 Roll-Up Integration Cases***, Stakeholder Draft 1, December 2013

   Synopsis

   This report describes the efforts of the EIPC Steady State Modeling and Load Flow Working Group (SSMLFWG) to produce roll-up integration cases for the Eastern Interconnection for 2018 and 2023. The intended purpose of these integration cases is to act as baselines for further scenario analysis. The report is based on power flow analysis.

   Relevance to This Project

   This report provided some valuable insights regarding expectations for load growth in different areas as provided by project participants, many of whom were power companies.

   Summary of Key Insights and/or Data

   - Considering the different service territories represented by the different power companies participating in the project, expectations for load growth can be characterized as averaging on the order of 1%/year. Over a long period of time (e.g. 35 years), this can compound a significant amount of additional demand that will require significant development of generation and transmission assets. This potential future demand represents an added uncertainty facing the evolving generation fleet.

4. ***Eastern Renewable Generation Integration Study***, November 2013, NREL Technical Review Committee, Bloom, Townsend, et al

   Synopsis

   This lengthy presentation captures a discussion of potential system operations issues associated with high penetrations of solar and wind generation in the Eastern interconnection.

A study was performed to examine renewable generation at a sub-hourly time resolution. Generation expansion was modeled using the NREL ReEDS model.

Relevance to This Project

This report was useful in that it independently identifies and confirms several key modeling challenges and solution strategies identified in the DOE FT study, thus helping to provide a basis for the approach taken using US-REGEN and unit commitment analysis.

Summary of Key Insights and/or Data

- The study noted the importance of bilateral power purchase agreements that affect energy flows. This is also a limitation of the analysis in the DOE FT study.
- The study noted that detailed operational constraints and unit-specific data are needed for analysis of generation; US-REGEN and the unit commitment model used in the DOE FT study were able to address these issues to some extent.
- The study noted key uncertainties related to transmission system additions, generation additions and retirements, and gas and coal prices. The DOE FT study addressed the first and third concerns through parametric analysis, and use of US-REGEN allowed a full modeling of long-term fleet transition via retirements and investment.
- Most of the scenarios contained significant amounts of coal and gas generation in future years.
- The report noted that interactions with ERCOT or WECC were neglected; US-REGEN entails simultaneous modeling of all regions for generation expansion.
- Similar to US-REGEN, a simplified inter-regional transmission network was used. The report also noted that some regional transfer capacity was unconstrained.
- As with US-REGEN, aggregated representation of some generation was done to speed up computation times.
- The report noted that no minimum turndown limits or minimum startup or shutdown times were imposed for IC, CT or PS units; these assumptions were made to speed up computation times.
- Two hour time resolution on unit dispatch was used.

5. ***Eastern Wind Integration and Transmission Study***, 2011 EnerNex, NREL/SR-5500-47078

Synopsis

This report studied future high wind penetration scenarios. The report framed the following key questions:

- Can the electric power grid accommodate very high amounts of wind generation without unacceptable impacts on grid security or reliability?
- Are significantly larger amounts of wind generation possible given limits posed by the transmission system?

This study is essentially the eastern counterpart to the later WSIS study. This study focused on levels of 20-30% generation share for wind. Four different scenarios representing different levels of wind penetration and different combinations of on and off-shore wind were analyzed.

Relevance to This Project

Similar to the reasoning for including the WSIS Phase 2 study, this report was reviewed for insights regarding assumptions and methodology, as well as for comparison to results obtained in the DOE FT study.

Summary of Key Insights and/or Data

- In essence, the study concludes that enabling high levels of wind generation share in 2024 would require substantial additional transmission expansion. Given that US-REGEN results suggest even higher levels of renewable generation (given RPS standards and other drivers), challenges seen in this report are likely to be even more significant for the longer-term future assessed in the DOE FT study.
- The report concludes that for wind to supply 20% of electric generation in the eastern interconnect, approximately 225 GW of wind capacity would have to be added. The corresponding result for 30% wind penetration is 330 GW.
- The report notes the criticality of transmission expansion, observing that building new transmission capacity has a longer lead time than building new wind capacity. The report notes that without substantial transmission expansion, significant amounts of curtailment of wind generation occur in all of the 20% wind penetration scenarios. The report acknowledges that the feasibility of such large transmission expansion is uncertain.
- The report also notes that grid integration costs for substantially more wind would be manageable if significant changes were to occur to market and tariff structure, as well as in how generation operations are managed. Such assumptions carry significant uncertainty.
- The report acknowledges that frequent unit dispatch occurs driven by grid security requirements, implying that significantly more operational flexibility demand develops, as observed in the DOE FT study results.
- The report provides a clear definition of the different types of reserve requirements: contingency, operating, regulating, and spinning. The report concludes in most scenarios that large increases in regulating reserves would be required.
- The report notes that significant increases in wind generation will likely result in less operation or retirement of conventional resources (e.g. coal). While there could be a cost impact due to this effect, another important concern is a reduced population of dispatchable assets available to provide operational flexibility in support of significantly great renewable generation.
- In evaluating wind integration and delivery costs, the report notes that the analysis neglected any additional regulating reserve requirements associated with wind variability/uncertainty, and that the wind resource one hour ahead is known with perfect certainty.

- The report makes an excellent observation that an added level of complexity requiring further research is operational challenges associated with AC power flows: voltage and reactive power compensation, dynamic and transient stability, and HVDC terminal control. It is very likely that analysis of such issues may lead to additional capacity requirements.
- The report notes that fuel price sensitivity studies were not included.
- The report suggests further analysis of unit commitment outputs to assess the impacts of variable generation on other assets – precisely a major goal of the DOE FT study.

6. ***ERCOT Presentation, EPRI Fossil Generation Assets and Power System Flexibility Workshop***, 2013, Surendran, Resmi

Synopsis

This presentation examined wind generation in the ERCOT region. It characterizes the extent of wind generation, as well as the grid and market conditions in which this wind operates.

Relevance to This Project

This reference was of particular interest because the detailed examination of the ERCOT area with its extensive wind generation informed the decision on the DOE FT project to concentrate on Texas as one of the detailed regions for which unit commitment analysis was performed.

Summary of Key Insights and/or Data

- The presentation shows a projection of capacity demand and reserve, indicating that the forecast reserve margin in ERCOT will be on the order of 14% by 2022.
- The presentation notes that ERCOT experienced 28% wind generation in May 2013, thus suggesting that this is a region which is likely to require significant operational flexibility from firm resources in support of high levels of renewable generation.
- The presentation notes that in ERCOT in early August, wind peaks in the early morning hours, whereas load peaks in the evening hours. It notes that in early February in ERCOT, wind tends to have a much more steady output throughout the day.
- The presentation identifies several key operational issues with the large amounts of wind generation possible in ERCOT:
  - Significant frequency deviations
    - High frequency due to fast ramp ups associated with wind (which could lead to demand for ramping to low turndown in non-wind assets)
    - Low frequency due to fast ramp downs associated with wind curtailments
  - Inadequate transmission for projected wind capacity growth
  - Higher ancillary service requirements
    - Non-spinning reserves increase by roughly 20%
    - Regulating reserves increase by roughly 10%

- Ramp duration curves shown in the presentation suggest significant amounts of positive and negative ramps for much of the year.
- Presentation notes that ERCOT is developing a reliability assessment tool (which implies that reliability impacts associated with high wind penetrations area concern)
- The presentation notes that an added market approach to addressing wind impacts is establishment of a minimum price for ancillary services, e.g. non-spinning reserves.
- The presentation concludes that with much higher wind & solar penetration into generation, flexible resources supporting steep changes in “net load” (term for non-renewable generation to meet load) may be needed.
- The presentation also concludes that new ancillary service products are valuable as they incent development of flexible resources.

7. ***Flexible Coal: Evolution from Baseload to Peaking Plant***, December 2013, NREL/BR-6A20-60575

   Synopsis

   Based on an assessment of an unidentified North American coal plant, this white paper provides an overview of types of cycling, impacts of cycling. The target audience is policymakers. The white paper recognizes that cycling impacts often have latency (i.e. delay before full scope of impacts are apparent). Principally attributes cycling damage to thermal transients. The report discusses both damages and operational responses for the units at the specific plant that was evaluated. The white paper provides a nice summary of key cycling impacts as a reference.

   Relevance to This Project

   This report is of particular interest as it looks at the impacts on a coal plant, and it provides a good high level summary of damage impacts and timing due to cycling. EPRI research confirms most of the cycling impacts cited in this paper.

   Summary of Key Insights and/or Data

   The paper helps confirm EPRI research regarding definitions of different types of cycling and their impacts, but provides little information that directly affects assumptions or the approach to the modeling done in this project.

8. ***Hawaii Solar Integration Study***, NREL/TP-5500-57215, June 2013

   Synopsis

   This study was a detailed examination of the effects of high penetrations of solar and wind on the electric grids in the Hawaiian Islands. The study included detailed computer modeling and simulations of the generation and transmission systems on each island to assess how future high wind/solar penetrations will affect generation.

Relevance to This Project

This report was of interest because review of an analysis of an isolated system permitted a better understanding (via comparison w/US-REGEN results) of the effects of inter-regional interactions.

Summary of Key Insights and/or Data

The study yielded several interesting insights:

- Less variability results from distributed PV systems vs. central station PV, principally due to the fact that weather related impacts on output are less likely to simultaneously adversely affect all resources in the distributed case.
- Variability is generally less for a combination of wind and solar as opposed to all solar, primarily due to the fact that wind and solar output don't follow the same patterns.
- The study notes that smart grid capabilities are an important need in parallel with increased distributed PV, otherwise power companies may not be able to curtail production for non-renewable assets, thus resulting in less optionality for grid operators.
- The study notes that central station solar presents some desirable characteristics: centralized control, potential curtailment, and grid support.
- In essence, the study notes the same issues with the variability of renewable resources and their impact on ramping for firm resources as in other reports reviewed here.

9. ***Impacts of Wind and Solar on Fossil-Fueled Generators***, Lew, D., et al, IEEE Power and Energy Society General Meeting, NREL/CP-5500-53504, July 2012

Synopsis

This paper was essentially a preview of the WSIS Phase 2 report reviewed elsewhere in this report. The paper addressed the potential emissions and cost impacts of added non-renewable asset cycling driven by higher levels of renewable generation.

Relevance to This Project

This paper was reviewed for any potential additional insights from NREL's analysis in WSIS Phase 2.

Summary of Key Insights and/or Data

- An interesting observation in the paper is that, depending on coal and gas fuel prices, on average each 3 MW of variable generation results in the necessity to reduce output from 1 MW of dispatchable generation and to decommit 2 MW of dispatchable generation. This observation underscores the depth of added flexibility needed to support increased levels of variable generation.
- The paper describes the aggregations of generation types used in the WSIS Phase 2 study; while not the same as those used in the US-REGEN analysis for the DOE FT study, they are similar and validate this aggregation approach.
- Comparison of lower bound cost data from APTECH for hot, warm and cold starts implies that a warm start is roughly 2x more expensive than a hot start, and a cold start is

roughly 3x more expensive than a hot start. This observation suggests that frequent starts and stops, or prolonged periods of unit shutdown are likely to create significantly more cost that hot starts.

10. ***Integrating Intermittent Renewable Energy Technologies with Coal-Fired Power Plant***, 2011, IEA Clean Coal Centre CCC/189

Synopsis

This report, by the International Energy Agency's Clean Coal Center, discusses the potential impact on coal-fired power plants resulting from growing levels of variable generation from renewable energy resources.

Relevance to This Project

This report presents an international perspective on the interaction between increasing variable generation and fossil generation assets.

Summary of Key Insights and/or Data

- The report notes that many existing coal units are now required to operate in other modes than baseload, e.g. two-shifting.
- The report defines flexible operations as peaking, load-following, two-shifting, on-load cycling, and weekend shutdown. Excellent definitions are provided for these modes.
- The report describes the difference between hot, warm, and cold starts, and describes conditions when these occur.
- The report notes that the "hotel load" (i.e. energy consumed by the coal unit itself) can increase from less than 0.5% of total output to over 5% depending on the flexible operations mode. Essentially, the hotel load doesn't decrease proportional to overall output level, thus representing something of an energy penalty for flexible operations, in addition to adverse heat rate effects.
- The report notes that the adverse operational effects of flexible operations could be mitigated if a unit were designed with flexible operations in mind. An example of such a unit is cited (although this is unusual.) Discussion of this example, the Castle Peak B unit in Hong Kong, notes that part of the mitigation is achieved through careful management of unit ramping and a deep understanding by plant staff of the impacts of flexible operations.
- The report provides a good summary of principal impacts on a unit due to cycling (Table 11.) It also provides a good summary of sources of additional O&M costs associated with cycling (Table 12.)
- The report provides a useful section discussing operational strategies to mitigate impacts of cycling. It is clear that these strategies are somewhat sophisticated and require a procedural and training basis for successful implementation.
- The report provides an interesting summary of the level of equipment monitoring for a particular plant.

- In discussing another study of emissions impacts of cycling, the report makes the important observation that emissions impacts are not only due to less efficient plant operations, but also due to off-normal conditions for environmental controls equipment, resulting in less inherent efficiency for these systems under cycling conditions.
- The report discusses some of the design advantages/disadvantages of steam boilers in supercritical coal plants relative to cycling operations.

11. ***Investigating a Higher Renewables Portfolio Standard in California***, Executive Summary, Energy & Environmental Economics, Inc., January 2014

    Synopsis

    The report presents a study of the impacts of a 50% renewable portfolio standard (RPS) for California, implemented by 2030. The study was funded by several power companies: Los Angeles Department of Water and Power (LADWP), Pacific Gas & Electric (PG&E), Sacramento Municipal Utilities District (SMUD), San Diego Gas & Electric (SDG&E), and Southern California Edison Company (SCE). The goal of the study was to evaluate operational challenges and potential consequences associated with a higher RPS requirement. A companion study was also conducted to examine smart grid technologies that potentially could facilitate adoption of a higher RPS. The geographic scope of the study was a combination of the California ISO, LADWP, and Northern California balancing areas. Several scenarios were evaluated, some reaching up to 15 % of electricity load served by wind and 28% of load served by solar, which exceeds peak levels of generation share observed in high renewables grids like Germany and Spain.

    Relevance to This Project

    This study is of interest because it looks at a very aggressive level of renewable generation share, similar to levels reached in 2050 in the US-REGEN modeling done as part of the DOE FT study. It is also of interest as it is one of the few studies commissioned by power companies.

    Summary of Key Insights and/or Data

    - The consultant performing the study used an in-house model called REFLEX to assess renewable impacts, availability of resources vs. changing load conditions, etc. The study focused on exploring potential consequences through evaluation of a range of scenarios representing different generation mixes, as opposed to seeking an "optimum" generation mix.
    - A key conclusion is that at renewable generation levels above 33%, the model is only able to ensure grid stability by requiring a considerable amount of generation in excess of that required by load plus any exports. This conclusion holds even when it assumed that thermal generation output is reduced to minimum levels. The increase in over-generation appears to be non-linear as well: at 40% RPS, over-generation is calculated to be 5 GW, while at 50% RPS, over-generation is calculated to be over 20 GW.
    - In order to avoid stressing the transmission network, given the over-generation described above, the model assumes that renewable generation can be curtailed to the degree

necessary. The report notes that this approach also has the side effect of allowing the model to avoid much of the ramping that would otherwise be required.

- Generally, the report estimates that retail electricity rates would increase as much as 9-23% for a 50% RPS, relative to a 33% RPS. In scenarios assuming higher future natural gas prices, retail electricity prices are estimated as high as $0.27/kWh.
- The report concludes that, despite assumption of comparable levelized costs of electricity production, renewable generation greater than 33% provides little resource adequacy benefits.
- The report estimates that concurrent transmission investments to enable a 50% RPS range from $9-15B depending upon the specific scenario.

12. ***PJM Renewable Integration Study***, GE Energy Consulting, February 2014

Synopsis

This report focused on assessing the impact of increased penetrations of wind and solar generation resources on grid operations in the PJM system. The report sought to assess operational, planning, and energy market effects as well as potential mitigation/facilitation measures. The study focused assessment on the year 2026. The study considered ten different scenarios based on different assumptions for on-shore and off-shore wind, solar, and either 20% or 30% total renewable generation share.

Relevance to This Project

This report was reviewed due to its recent publication and its focus on an area with significant coal and gas assets.

Summary of Key Insights and/or Data

- As with many other studies evaluated in this literature review, this study looked an existing fleet and did not consider fleet asset investment decisions over time.
- The study also did not consider economically driven early retirements of non-renewable assets (which may potentially affect the future fleet's capability to provide capacity and provide flexible operations in support of increasing variable generation.)
- The study concludes that the impact on PJM operationally could be minimal if transmission expansion occurs and if regulation is increased to assure target levels of transmission congestion. It is also not clear if the study considered all additional costs associated with transmission expansion.
- It is not clear if the report systematically included near or long-term costs created by unit cycling.
- The study acknowledged that the levels of renewable generation assessed would produce significant cycling for non-renewable assets.
- As with the WSIS Phase 2 study, this study essentially concludes that adverse emissions impacts due to cycling are effectively canceled out by avoided emissions associated with reduced fossil generation share.

- The report finds that the grid operator would need to add roughly 3,000 miles of transmission (~$14B cost) and would need to increase the regulation requirement from 1,200 MW to 2,700 MW for the 30% renewable generation share scenario. These are very substantial requirements.
- The report recognizes that fossil generators would likely see reduced gross revenues. This underscores the concern regarding potential accelerated fossil unit retirements and adverse effects on fleet flexible operations capabilities.
- The report concludes that NGCC units provide the majority of cycling for the fleet, while coal units tend to be load following. The report notes that potential reliability impacts associated with increased flexible operations were not quantified.
- Overall, this study echoes many of the same points presented in the WSIS Phase 2 report, and also supports the need for the integration of analysis of longer-term investments in generation assets with operational impacts via unit commitment analysis.

13. ***Power System Flexibility Metrics: Framework, Software Tool and Case Study for Considering Power System Flexibility in Planning***, December 2013, EPRI 3002000331

Synopsis

This report discusses the development and application of flexibility metrics for a generation fleet through use of an analysis tool (entitled "inFlexion") applied to unit commitment analysis results. The report includes a case study of application of the tool. This tool analyzes the flexibility characteristics of a given fleet from a number of perspectives: flexibility requirements arising from the market conditions and load, statistical analysis of the flexibility characteristics of the generation assets in the fleet being analyzed (e.g. ramping capabilities), analysis of the flexibility available from the assets based on how they are dispatched in the unit commitment analysis, and analysis of transmission system constraints on utilization of generation asset flexibility capabilities. The focus of the tool and the report is understanding at a fleet level of the flexibility required and how that flexibility will be used.

Relevance to This Project

This report, based on research performed by EPRI's Power Delivery & Utilization sector, provides a thorough examination of ramping requirements and how to characterize flexibility in terms of metrics. Understanding the thinking and approach underlying the inFlexion analysis tool was a valuable reference as modeling approaches for the DOE FT project were developed.

Summary of Key Insights and/or Data

- The inFlexion tool focuses principally on ramping requirements implied by a unit commitment analysis of a given generation fleet. It thus presents a perspective on how a given system will meet its flexibility needs given a certain asset mix. It does not directly address questions regarding the engineering feasibility of different assets' ability to provide the needed ramping performance.
- However, consideration of the flexibility metrics defined and calculated by the inFlexion tool helped inform the engineering assessment of the US-REGEN results in terms of evaluating hourly generation variability and hour changes in unit capacity factors.

14. ***Power System Operational and Planning Impacts of Generator Cycling due to Increased Penetration of Variable Generation***, December 2013, EPRI 3002000332

Synopsis

This report examines the possibility of new operational modes and assesses methods to reduce the overall cycling duty on system generation assets through appropriate cost recovery mechanisms. The intent of the report is to give power system operators and planners an insight into the degree which a wide range of factors affect the allocation of cycling operations to generators. The report summarizes and evaluates the outcomes of the second phase of the Western Wind and Solar Integration Study (separately reviewed elsewhere in this report for the DOE FT project). The report presents an overview of operational measures to enhance and retain flexibility from generators, including algorithms for hot-standby and dynamic costs of cycling. The report includes a case study of two systems utilizing the operational measures cited above.

Relevance to This Project

This report focuses on market products which allow more valuation and access to flexible operations products (e.g. ramping products offered in the California ISO). It cites data from other EPRI reports on the impacts of cycling on unit availability, some of which are separately included in this literature review. The report presents a grid operational perspective on the impacts of flexible operations.

Summary of Key Insights and/or Data

- The overall approach is based on equivalent starts/stops as a metric for cycling. Underlying this assumption is the question of the validity of the accuracy/feasibility of equating all cycling related damage effects to equivalent starts. It's not clear that cycling impacts can be fully characterized solely in terms of measuring increased start/stop frequency and cost/stop, cost/start. EPRI research indicates a substantial "latency" in appearance of damage effects, e.g. increased HRSG tube failure in CTCCs becoming apparent over 3-5 years. A concern with analyses like the Phase 2 WWSIS work is thus that the cycling impact and costs could potentially be underestimated.
- The approach also assumes an islanded system and thus didn't address inter-regional energy transfers.
- Another important aspect of increased flexible operations is that impacts may not be limited to simply worsening existing damage mechanisms already addressed by existing maintenance activities. It's possible that new maintenance activities or strategies will be needed in addition to modifying existing maintenance frequencies, practices. This is an area of active research.
- The report makes several salient observations related to prior studies:
  - The Phase 2 Western Wind Integration Study (WSIS 2) gives consideration to cycling costs, but that the opportunity costs associated with increased hours which supporting generation assets spend on forced and planned outages due to added flexible operations were not addressed.

  - As the frequency of starts increases, the period over which the operational and maintenance costs are recovered becomes smaller, which negatively affects the net present value of the maintenance actions required to restore the generator to service.
  - Increased flexibility requirements will result in a greater number of starts and load following that conventional plants will experience.
  - Integration of solar PV, in particular, will give rise to increased double two shifting cycling of CCGT plant in many systems.
  - The impact of starts on generation reliability is real and significant. Increased starts may result in higher number of forced outage and planned outage periods.
  - Decreased fleet reliability will result in greater scarcity prices for energy and ancillary services in power systems.
  - The costs associated with incremental starts are not constant and are dependent on a number of factors including plant age, cumulative starts to date and cycling frequency.
  - Avoiding generation starts (warm and cold starts in particular) where possible is one means to improve overall system reliability and reduce costs.
- Awareness of the incremental costs associated with generator cycling within the decision making process would assist in the management of the overall reliability of a system, while reducing the total time spent offline for planned or forced outages.

15. ***Resource Adequacy and Economic Impacts of Integrating Intermittent Resources***, November 2013, Astrapé Consulting

    Synopsis

    The scope of this report is an analysis of renewable resource integration using an hourly unit commitment analysis, focusing on the California Independent System Operator (CAISO) system in 2020, with the assumption of 30% generation from renewable energy resources. The analysis tool used was SERVM (Strategic Energy & Risk Valuation Model; SERVM is a reliability and hourly production cost simulation tool.) The authors of the report, Astrapé Consulting, have worked with EPRI on a number of renewable integration research projects. The report presents results of SERVM simulations, which take into account a wide range of weather, economic, and unit performance scenarios, with goal of providing a comprehensive perspective of the potential costs and risks of integrating small or large portfolios of intermittent resources.

    Relevance to This Project

    This report is of interest in that it uses a unit commitment modeling approach to look at the impact of high levels of renewable energy generation. The report authors have worked extensively with EPRI's Power Delivery & Utilization (PDU) sector and are thus very familiar with related research performed by PDU. The multiple scenario-based approach also provides some useful perspectives that informed evaluation of the US-REGEN modeling results for the DOE FT project.

Summary of Key Insights and/or Data

The report focused on forecast uncertainties for load, solar, and wind resources on day-ahead, multi-hour ahead, and intra-hour bases. Case studies were performed for the state of California to understand both system cost and reliability impacts of renewable resource integration. A number of interesting technical conclusions were presented:

- The simulation of forecast uncertainty demonstrates that there is reliability benefit to increasing reserve targets when integrating renewable resources (although the economy of doing so may or may not be justified.)
- The impacts of integrating renewable energy resources as modeled in this study suggest that more refined modeling of unit flexibility should be performed (e.g. updated ramp rates, startup times, fuel prices, heat rates, fuel price forecasts, and emissions requirements). The integration of the effects of variations in these variables is precisely the objective of using US-REGEN, unit commitment analysis, and engineering expert judgment as described in the DOE project for which this literature review is being performed.
- The assessment of the sensitivity of load forecast error to the time resolution of load forecasts (e.g. hourly vs. longer time periods) suggests that the hourly resolution used in US-REGEN and the unit commitment analysis for our DOE project is reasonable.
- The report identifies economic uncertainty as largest contributor to historic load-shed events. This supports the use of US-REGEN, which models the impact of overall economic conditions.
- The report introduces a parameter called ELCC (effective load carrying capability) that is essentially a “dispatchable equivalent” for non-dispatchable generation. Typical ELCC values cited for wind are below 20% and for solar below 60% (effectively dispatched as a function of nameplate rating).
- The report also suggests that forecasting uncertainty is a big factor in forcing cycling of conventional assets.
- The report includes charts showing the relation between operating reserves in a high-renewable mix versus system reliability, indicating that this relationship is quite nonlinear.
- The most important conclusion stated in the report reinforces the need for the DOE Fleet Transition study: “The simulation of forecast uncertainty demonstrates that there is reliability benefit to increasing reserve targets when integrating renewable resources. However, the cost increase of such a procedural change may be larger than a strict economic decision would justify.” This statement implies that economic forces alone may not ensure preservation/construction of sufficient resources necessary for flexible operations support in a high-renewable mix. This concern is at the heart of the DOE Fleet Transition study.
- The applicability of the report's conclusions are limited by the use of California for the case study (there are significant differences across different regions of the U.S.) and by the assumption of unlimited transmission capacity (the US-REGEN results from the DOE

FT study suggest that transmission capacity is a key sensitivity factor.) In addition, this study analyzed California as an island, whereas in reality inter-regional energy transfers are a very important factor in analysis of the impacts of increasing flexible operations driven by increased deployment of renewable energy resources. All of these observations suggest that the approach taken in our DOE project is an important advance in this type of analysis.

16. ***The Western Wind and Solar Integration Study Phase 2***, September 2013

Synopsis

Phase 2 of the Western Wind and Solar Integration study (WSIS) was completed to evaluate the impacts of increased cycling of fossil fuel assets resulting from higher levels of generation from renewable energy resources. The study evaluated the costs and emissions impacts associated with this increased cycling. A simulation of the western grid is used with different scenarios representing different levels of renewable energy penetration. The study focused only on simulating the grid in the Western U.S. Key features of the study included the assumption of a natural gas price of $4.60/mmBtu, substantial cooperation between balancing authorities within the modeled region, and least-cost generation and transmission dispatch without modeling of any bilateral transactions, and modeling of grid operations on a sub-hourly basis. The study focused on simulation of an existing generation fleet and associated transmission system, i.e. modeling of asset retirements and new investments over time was not part of the scope of the study. The study is principally based upon supporting studies by GE Energy and Intertek-APTECH. A separate Technical Review Committee was also convened and met on a frequent basis to review project approach and results. In essence, the study concluded that while cycling incrementally increases costs and emissions, the avoided fuel costs and emissions associated with fossil generation displaced by increased renewable resources dwarfs any of these incremental increases.

Relevance to This Project

This study is a key reference in that it really integrates results from three important reports, i.e. not only the parent report but also supporting reports prepared under contract to NREL by GE Energy and APTECH. APTECH in particular is an important organization in the field of assessing impacts of unit cycling, having done extensive consulting in this area. Since the WSIS Phase 2 specifically was focused on cost impacts of cycling, the report is of particular relevance.

Summary of Key Insights and/or Data

The WSIS Phase 2 is by far one of the most comprehensive assessments of cycling impacts associated with significantly increased renewable energy generation. It provides highly valuable insights. However, there are several aspects of this study which highlight the need for additional research which looks both at long-term transition of the generation fleet and an associated engineering assessment of the levels of increased operational flexibility needed. Several characteristics and assumptions of the WSIS Phase 2 support this need:

- The applicability of this study to other regions in the U.S. may be limited given significant differences in the regional generation mix. The Western region has relatively less coal and nuclear than eastern regions, which affects the generation mix's ability to absorb and provide flexible operations in response to increasing variable generation.

  – The trend in increasing costs due to cycling summarized in the study would presumably depend on the generation mix; in particular, if another region with a higher share of coal and/or nuclear experienced similar levels of renewable energy penetration, cost impacts might be higher.
  – Using a normalized metric like $/MWh-renewables may not be a good metric in that for regions with less renewables, this ratio could be significantly higher.
  – APTECH notes in its supporting study that damage as a function of higher ramp rates is a non-linear relationship. For a generation mix with a higher level of coal, cost of ramping could potentially be higher.

- A fundamental assumption underlying the cost impact assessment is that long-term effects of cycling which otherwise may not be immediately apparent can be almost entirely offset if reasonable near-term capital and maintenance investments are made. In practice, EPRI research suggests that significant long-term consequences of cycling are experienced and affect capital investment decisions regarding both existing and new assets. Thus modeling generation asset investments and retirements is a valuable feature of any research on the impacts of flexible operations.
- A number of aspects of potential cost impacts were acknowledged, but not explicitly modeled:
  – APTECH noted that CTCCs have higher ramp rate costs due to operational constraints on the HRSG and steam turbine, but that these costs weren't quantified.
  – APTECH recommended further sensitivity analysis related to assumed fuel costs, generation mix, retirement costs, and costs of adding additional flexible resources. These questions can be addressed through an approach which includes asset investments, as EPRI is doing in this study.
  – While the supporting studies acknowledge that low turndown operations are another potential source of cost impacts, it is not clear whether low turndown was modeled as part of the simulation approach in WSIS Phase 2.

The WSIS-2 study also captures several valuable observations and conclusions regarding the nature of flexible operations, many of which are confirmed by EPRI research. Key observations include the following:

- Cycling damage
  – As also noted in EPRI research, creep-fatigue interaction is the principal damage mechanism driven by cycling.
  – The APTECH supporting study also notes the latency of damage effects (multiple years.)
  – Probability distributions of full forced outage duration indicate that while boilers have the highest probabilities, generators experience particularly long outages when they occur.

- APTECH generally defines cycles spanning >15-20% of gross capacity as significant.
- Relatively limited data exists in the APTECH database associated with faster ramp rates.
- Heat rate degradation has been observed over long periods (i.e. 10 years) on the order of 10%, of which 1-5% is believed attributable to cycling.

- Cycling costs
  - The basic starting point for APTECH is a generic "loads model" which infers cycling behavior from an analysis of hourly generation data. This is then followed by application of a generic damage model (developed and tested based on a large number of prior cycling studies) that calculates creep/fatigue effects based on the cycling analysis. Damage accumulation rates are baselined to fatigue damage associated with an idealized gentle load transient known as an equivalent hot start (EHS).
  - There is substantial uncertainty in cycling cost data as reported by APTECH.
  - Cold starts and low turndown are main cycling cost drivers per APTECH's supporting study.
  - In terms of numbers, the majority of "cycling" events in high renewables penetration cases appear to be low turndown events, closely followed by cold starts. Comparatively, much fewer warm or hot starts.
  - Interesting that although fewer in numbers, in terms of cost, warm starts are about as significant as cold starts.
  - Median cold start costs for each generation type ~1.5-3x higher than corresponding hot start cost. Holds up to the 75th percentile for the distributions of cold and hot start costs.
  - Aeroderivative units have almost equal cold, warm, hot start costs due to inherent flexible design.
  - Low range cycling costs seem to increase relatively gradually (aggregate WECC costs from ~$120M to ~$170M) from no wind case through 30% renewables case.
  - High range cycling costs seem to increase relatively gradually (aggregate WECC costs from ~$400M to ~$600M) from no wind case through 30% renewables case.
  - Cycling costs (for upper bound values) are 40-50% of total non-fuel operating costs.
  - Data on the distribution of capital & maintenance cycling costs per MW as a function of unit capacity indicate that these costs are relatively insensitive to unit capacity.

- Distribution of Cycling across assets
  - GE analysis concludes that most of cycling seen on CTCCs, CTs (not coal). Low turndown mostly occurs in CTCCs, cold starts mostly occur in aeroderivative CTs.
  - High number of warm starts observed from APTECH data for small units (~50 MW) and then another concentration at larger unit sizes (~575MW).

- APTECH/GE caveats on their data, analyses:
  - APTECH acknowledges that their data set contains little cycling data for large supercritical units, so costs associated with cycling such units (as might occur in other regions) would not likely be represented => applicability of these results to other regions thus questionable.
  - APTECH's modeling and analytical methods have been built upon a historical data containing a large quantity of gas-fired steam unit data; however, gas-fired steam units do not represent a majority of the current fossil capacity, and will not likely be representative of the future generation mix.
  - GE acknowledged that increased forced outage frequency due to cycling wasn't included in their analysis of impact on generator revenue – the argument is that the changes in forced outage frequencies are so low that this is a negligible effect.
  - Data is lacking cases of "deep" cycling, i.e. load-following from near-minimum to near maximum output conditions.
  - The APTECH top-down methodology limits the portion of cycling costs that is independent of unit loading variations to 50-75%.
  - The APTECH methodology includes inclusion of loss functions representing soft constraints, to allow small violations of above limit to smooth the data and improve the linear regression fit; and to increase losses if near-term anticipated capital spending is high (based on premise that these expenditures are driven by cycling.)
  - The figure of merit in cost calculations is equivalent hours of operation.
  - APTECH's bottom-up unit-specific analysis methodology includes review of >=95% of all work orders over past 7 years at the unit in question.
  - APTECH asserts that accurate estimates of total unit cycling costs can be derived based on regression analysis of historical unit damage.

Generation Fleet Transformation Studies

The scope of the Generation Fleet Transformation Study literature review is summarized in Table B-2 below:

Table B-2
Generation Fleet Transformation Study Literature Review Scope

17. ***2012 National Electric Transmission Congestion Study Preliminary Findings - Stakeholder Consultation Webinars***, August 2012, David Meyer, Office of Electricity Delivery and Energy Reliability U.S. Department of Energy
18. ***2013 Special Reliability Assessment: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach***, November 2013, NERC/California Independent System Operator
19. ***Flexibility in Europe's power sector - an additional requirement or an automatic complement?***, Bertsch, et al; EWI Working Paper No 13/10, June 2013
20. ***Flexible Operation of Current and Next-Generation Coal Plants, With and Without Carbon Capture***, EPRI, Palo Alto, CA: 2013. 3002001561.
21. ***Future Perspectives in Operations: Managing Through a Changing Operating Regime***, 2013, EPRI 3002001129
22. ***Grid Energy Storage***, 2013, DOE, http://energy.gov/oe/downloads/grid-energy-storage-december-2013
23. ***Grid Reliability Consideration for High Levels of Demand Response***, 2013, EPRI 3002002330
24. ***Heterogeneous Unit Clustering for Efficient Operational Flexibility Modeling for Strategic Models***, Bryan S. Palmintier and Mort D. Webster, MIT, ESD-WP-2013-04, January 2013
25. ***Impact of Cycling on the Operation and Maintenance Cost of Conventional and Combined Cycle Power Plants***, 2013, EPRI 3002000817
26. ***Impact of Minimum Load Operation on Steam Turbines***, EPRI, Palo Alto, CA: 2013,3002001263
27. ***Impact of Unit Commitment Constraints on Generation Expansion Planning with Renewables***, Palmintier, Bryan, and Mort Webster. IEEE, 2011. 1–7. Web.
28. ***Increasing the flexibility of coal-fired power plants***, Henderson; IEA Clean Coal Centre, CCC/242, March 2014
29. ***Modeling and Evaluation of Iowa Hill Pumped-Hydro Storage Plant: Value in MSUD and in Larger Region***, Brownell, G. (SMUD), et al; Tuohy, A. (EPRI), et al, December 2013
30. ***Primer on Flexible Operations in Power Plants***, 2013, EPRI 3002000045
31. ***Reducing power plant derates, emissions, profit loss, and equipment damage from cycling and load-following***, Richards, G., NETL, 2012
32. ***The Power of Transformation: Wind, Sun and the Economics of Flexible Power Systems,*** International Energy Agency, 2014
33. ***The Spanish Experience in Electric Generation Capacity Turnover***, December 2009, EPRI 1020592
34. ***Unit Operational Flexibility: Low-Load Turndown of a Large Supercritical Boiler***, EPRI, Palo Alto, CA: 2013, 3002002087

17. ***2012 National Electric Transmission Congestion Study Preliminary Findings - Stakeholder Consultation Webinars***, August 2012, David Meyer, Office of Electricity Delivery and Energy Reliability U.S. Department of Energy

Synopsis

This presentation summarizes work by the DOE to assess congestion in several regions in response to a statutory requirement to perform such analysis. The DOE research presented results for four "mega-regions": West, Midwest, Northeast, Southeast. The analysis relied on public data and analyses, i.e. DOE did not do any of its own modeling. The research summarized in the presentation focused on technical solutions to potential congestion, and did not consider potential economic feasibility of any options.

Relevance to This Project

Given the criticality of transmission resources and potential expansion to any analysis assessing fleet operations, this report was chosen for review to gain any insights that would inform transmission assumptions used in the DOE FT project.

Summary of Key Insights and/or Data

- The presentation identifies some empirical indicators of transmission congestion: frequent use by grid operators of transmission load relief (TLR) procedure, frequent or recurrent disparities in wholesale electricity prices across regional markets.
- The presentation observes (as of the 2012 publication date) that the total of proposed renewable electricity generation projects exceeds available or projected transmission capacity in several regions, suggesting likely future transmission constraints.
- The presentation notes that the combined effects of environmental compliance, plant availability, and changing fuel prices on transmission congestion are unclear and may not be known for several years. (This suggests an added level of potential sensitivity of the future generation fleet's ability to absorb significant variable generation to transmission assumptions.)
- The presentation observes that much of the existing transmission infrastructure is aging and will require replacement before 2030.

18. ***2013 Special Reliability Assessment: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources – CAISO Approach***, November 2013, NERC/California Independent System Operator

Synopsis

This report focuses on considerations that all system planners and operators must address to reliably integrate significant quantities of variable generation resources into the bulk power system. This report highlights the California Independent System Operator Corporation's (CAISO) current efforts to address these challenges. The report recognizes that, operationally, an increase in wind and solar resources continues to challenge operators with the inherent swings, or ramps, in power output. This leads to increasing the amount of available regulating reserves and potentially carrying additional operating reserves. This report identifies the key system enhancements in planning and operations that are needed to promote reliable operations and maintain essential reliability services.

Relevance to This Project

This report of particular interest because it is one of relatively few reports focusing on reliability impacts associated with high penetrations of renewable generation.

Summary of Key Insights and/or Data

The report concludes that increasing variable generation deployment will strain grid reliability services, particularly driving more operations at low output levels (i.e. "low turndown") and the associated increase in ramping for dispatchable generation resources. Key generation resources may be economically driven out of the generation mix, even though they represent important resources of ancillary services. The report appears to view 20-30% generation from variable resources as a critical level of penetration.

The report provides specific recommendations (based on assessment of the CA ISO):

- Applying a uniform reactive power standard would help eliminate situations in which projects interconnecting later in time may need to wait for additional reactive power resources to compensate for unstable voltage conditions on the grid. Additionally, uniform requirements promote enhanced grid reliability and ensure all generation supports the interconnection's reliability needs.
- Variable generation resources should have the capability to receive and respond to automated dispatch instructions as well as maintain an ability to limit active power output, should there be a reliability need.
- Variable generation plants should be designed with consideration of more flexible ramp rate limit requirements, e.g. more flexible limits on power decreases due to declines in wind speed or solar irradiation (i.e., down-ramp rate limits), as well as the capability to ramp up in controlled increments.
- All generation resources should have the capability at the plant or interconnection level to contribute to the inertial and frequency response needs of the system, and all resources should have the ability to automatically reduce energy output in response to high system frequency. Variable generation plants should be encouraged to provide overfrequency droop response of similar character to that of other synchronous machine governors.
- Standard, valid, generic, nonconfidential, and public power-flow (steady-state) and stability (dynamic) models for VERs are needed and must be developed to enable accurate system representation.
- The report notes that while technical solutions may exist to mitigate reliability challenges arising from increasing deployment of variable generation resources, there is no market model that provides compensation for investments in these solutions or that determines what entities would share the costs.

19. ***Flexibility in Europe's power sector - an additional requirement or an automatic complement?***, Bertsch, et al; EWI Working Paper No 13/10, June 2013

Synopsis

This report, authored by the Institute of Energy Economics in Cologne, Germany, analyzes whether there is a need for additional incentives to assure adequate operational flexibility in electricity markets with high levels of renewable generation. The analysis simulated European electricity markets through 2050 using a linear investment and dispatch optimization model.

Relevance to This Project

This report was selected for review for several reasons: the European focus (where significant renewable generation already exists), the long-term time horizon of the analysis, and the consideration of both investment and unit dispatch (rare amongst research studies prior to the DOE FT study.)

Summary of Key Insights and/or Data

- Overall, the report concludes that a market design which incents least total system cost generation investment does not require any additional incentives to assure adequate fleet operational flexibility, i.e. a least-cost market model will provide flexibility as an automatic complement. In this respect, the DOE FT study differs significantly from this conclusion.
- The report results are based on two critical assumptions: gas prices will be such that gas-fired power plants and flexible CCS plants will be economically most attractive for investment, and that long-term cycling cost impacts are minimal. The first assumption is uncertain, and EPRI research would suggest that the second is not likely to be valid.
- The report notes, in contrast to its conclusion, that other studies and actual experience suggest that added incentives are needed to ensure flexibility.
- The simulation assumed that renewable investments will be made such that 80% generation from renewable is achieved by 2050.
- The simulation also assumed ramping and start-up constraints for non-renewable assets.
- The simulation performed hourly unit commitment analysis for four different time periods: 2020, 2030, 2040, and 2050.
- The simulation assumes that a balancing reserve equal to 10% of renewable generation is available each hour.
- The simulation assumes that CCS units can be shut down or started up in one hour (very aggressive.)
- The simulation assumes that additional electrical power can be obtained by shutting down the steam cycle of CCS units; this is an assumption of a capability that may not be widely available.
- The report notes that several periods exist during which significant additional firm generation capacity must be available to support variable generation.

- The report analyzes hourly volatility of "residual load" (equivalent to generation required net of renewable generation), and finds that this volatility is very significant, e.g. hourly fluctuations 25-100%.
- The report shows that the significant interconnected nature of the European grid and the substantial level of hydro-electric generation plays a significant role in the conclusion that flexibility needs can be met.
- The net effect of assumptions regarding flexibility is that overall, the simulation has access to excess capacity able to ramp up to necessary levels within 15 minutes. This is effectively an assumption of very high levels of operational flexibility (which is not supported by actual coal and gas unit experience.)

20. ***Flexible Operation of Current and Next-Generation Coal Plants, With and Without Carbon Capture***, EPRI, Palo Alto, CA: 2013. 3002001561

Synopsis

This EPRI report focused better understanding implications for existing pulverized coal plants when they are required to operate under changing load conditions. This report had several objectives similar to those of the DOE FT project:

- Assess flexible operations capabilities of the current coal fleet and implications of long-term flexible operations for units generally not designed for significant levels of cycling and ramping
- Assess available improvements for enhanced flexible operations that should be considered for new ultrasupercritical (USC) plants.
- Assess potential limitations in terms of flexibility when current CO_2 capture technology is retro-fitted to existing PC plants, as well as near-term opportunities for new build USC plants (oxy-fuel and solvent-based post-combustion capture) to enhance flexible operations
- Summarize long-term opportunities for new build CO_2 capture plants to enhance their flexible operations

The report was intended for existing coal asset users to assist in asset investment decisions relative in light of emerging CO_2 emissions regulations. The report also examined options to provide energy for solvent regeneration for post-combustion capture applications: NGCC, geothermal, and solar. Finally, the report considers anticipated flexibility of non-solvent CO_2 capture technologies.

Relevance to This Project

This report was selected for review in that in some respects it is a precursor to the current DOE FT project. Additionally, consideration of potential limitations imposed by CO_2 capture is highly relevant in light of recent proposed regulations for fossil plants limiting CO_2 emissions intensities to significantly lower levels.

Summary of Key Insights and/or Data

- Overall, the report emphasizes the importance of incorporating flexible operations into unit design, and discusses various options to achieve this. While valuable for new asset investment decisions, the report also highlights the challenges with achieving operational flexibility for existing units needing to meet CO_2 emissions limits.
- The report underscores the significant uncertainties associated with performance, economical operations, and environmental compliance under conditions where significant flexible operations are required.
- The report provides a good summary of damage impacts due to cycling on existing coal assets (based on other EPRI research).
- The report notes that for solvent-based post-combustion capture (PCC), there are PCC operating limits that effectively limit the minimum level of overall unit turndown:
  – Maintaining minimum PCC extraction pressure for solvent regeneration (typically around 60 psia for mono-ethanolamine (MEA) systems)
  – Maintaining steam flow through the LP turbines for stable turbine operations (should not be less than the design steam flow for the turbines prior to addition of PCC.)
- The report considers steam turbine functional requirements in light of both PCC and flexible operations:
  – Ability to shift steam output used for solvent regeneration to power production
  – Ability to maintain PCC operations under low turndown conditions
- The report summarizes several details relative to expected ramp rate and turndown limitations, as well as efficiency losses, for PCC and oxyfuel (air-firing and oxy-firing).
- The report notes that one strategy for increasing operational flexibility for solvent-based PCC is larger size solvent regeneration tanks, thus essentially increasing margin for available solvent under a range of operating conditions. Relative to this concept, the report notes some important design considerations which could have operational implications for flexible operations:
  – Maintenance of the "rich" solvent (i.e. solvent with CO_2) at or slightly below absorber bottom outlet temperature to avoid degassing and potential tank over-pressurization
  – Nitrogen or CO_2 blanketing of rich solvent to avoid solvent degradation due to reaction with O_2.
- The report provides summary tables of key operating parameters and costs associated with the three options described above for providing power for solvent regeneration from alternative sources.
- The report discusses flexible operations for chemical looping, an advanced technology concept for CO_2 capture. The over-arching comment was that due to the multiple sub-systems requiring carefully coordinated control strategies, developing chemical looping

capable of part-load operations would require a complex and advanced integrated control strategy. (This would certainly require additional research, testing, and demonstration.)

- The report notes the possibility that closed Brayton cycles may offer good flexibility capabilities due to smaller weight and volume of physical systems, lower thermal mass, and less power block complexity. However, this would require additional research, testing, and demonstration.

21. ***Future Perspectives in Operations: Managing Through a Changing Operating Regime, 2013,*** EPRI 3002001129

Synopsis

This EPRI report focused on how operating and management strategies have changed in response to changing operating regimes for generation assets. The principal objectives of the report were to:

- Evaluate the impact of changing operational requirements on day-to-day plant operations
- Address the implications of a coal unit transitioning from baseload to cycling/peaking modes of operation
- Address the implications of a gas unit transitioning from cycling/peaking modes of operation to baseload

Relevance to This Project

This report provides useful insights to the engineering assessment of the modeling results in the DOE FT study. Assessment of the potential implications of hourly generation and capacity variations in the DOE FT study is informed by insights from this report.

Summary of Key Insights and/or Data

- The report makes several important points relative to management of the plant staff in light of changing operational modes, e.g. management communications, clear understanding of new operational missions, and appropriate training of staff. The report particularly notes that if frequent unit start/stops are expected, this is an area for additional training.
- The report notes that extended coal storage times (e.g. that may occur for cases of prolonged unit layup between operational periods) create an added potential for coal bunker/silo fires. This is an important safety concern.
- The report notes that the schedule and scope for operator rounds must be revisited in light of a different operational mission.
- The report points out that it is very important to identify a priori key systems requiring special layup provisions for extended unit layup periods.
- The report re-emphasizes the importance of preventive maintenance (this implies that in light of changing operational mission, changes and/or augmentation of preventive maintenance programs may be needed.)

22. ***Grid Energy Storage***, 2013, DOE, http://energy.gov/oe/downloads/grid-energy-storage-december-2013

    Synopsis

    This report is an assessment of current power system grid resources in the U.S., as well as a discussion of key challenges associated with increasing the amount of grid storage available. The report focuses on four challenges related to the widespread deployment of energy storage: cost competitive energy storage technologies (including manufacturing and grid integration), validated reliability & safety, equitable regulatory environment, and industry acceptance. The report defines key goals associated with overcoming these challenges: cost competitive energy storage technology, validated reliability and safety, an equitable regulatory environment, and industry acceptance. The report notes key state regulatory developments that are driving increasing interest in energy storage. The report also summarizes existing storage technologies and their state of development, as well as the different types of services that storage enables/supports. This report does not address new policy actions, nor does it specify budgets and resources for future activities.

    Relevance to This Project

    This report was included in the literature review to assess any potential insights to the impacts of energy storage on a future fleet experiencing much higher levels of variable electricity generation. However, in practice, storage is such a small component of the overall resource base that it plays a minor role at this point in power sector modeling.

    Summary of Key Insights and/or Data

    - The report notes that currently, grid level energy storage is equivalent to roughly 2.3% of total U.S. capacity. At this level, storage plays a small role on a national scale in shaping how generation assets are operated and dispatched. The report provides some limited data on prospective costs for different storage technologies, but little information on how storage on a larger scale would be implemented or deployed in the future. Principally, the report provides a research agenda for grid level energy storage.

23. ***Grid Reliability Consideration for High Levels of Demand Response***, 2013, EPRI 3002002330

    Synopsis

    This EPRI white paper (authored by the Power Delivery & Utilization sector) focuses on (a) unique characteristics of demand response relative to bulk electricity system reliability needs and present contributions to system reliability, (b) identification of potential bulk system reliability impacts of high levels of demand response, and (c) identification of research needs necessary to address these impacts such that potential benefits of demand response as a system resource can be realized.

    Relevance to This Project

    This paper was chosen for review because it evaluates another potential source of variability from the perspective of the grid-connected central power station, i.e. increased variation in demand due to demand response (DR).

Summary of Key Insights and/or Data

- The report notes that due to advances in communications and control technologies, demand response is becoming more widely used across the industrial, commercial, and residential consumption sectors as both a capacity resource as well as an ancillary service resource. DR has increasingly been utilized to provide ancillary services in the form of spinning reserve and to cover short-term deficiencies in transmission or generation until longer time-frame solutions can be identified.
- The paper cites analysis from the 2012 North American Electric Reliability Corporation (NERC) Long-Term Reliability Assessment indicating that demand response is projected to rise to about 2.4% of internal load by 2022, i.e. a scale comparable to current energy storage across the U.S. grid.
- The paper notes that increasing use of DR as a power system resource has the consequence of potentially adversely affecting capacity payment revenue streams for peaking generation resources, which could result in lower investments in peaking generation assets, resulting in an adverse reliability impact. The "displaced" assets may provide important ancillary services.
- The paper also notes that the inherent uncertainty and lower predictability associated with how much DR is available and when effectively translates to a greater need for more flexible operations for existing firm generation assets (e.g. low turndown, cycling.) The paper notes that one source of uncertainty is changing customer perceptions of the adverse impacts of DR vs. incentives, which could change available levels of DR.
- The paper cites another consequence associated with DR uncertainty and predictability, i.e. difficulty in incorporating DR into long-term planning (which affects planning for firm assets and for transmission.) The NERC Integrating Variable Generation Task Force report on Bulk System Reliability Impacts of Distributed Resources reinforces this point relative to transmission.
- The paper also points out that the sustainability of planned DR is harder to determine considering the uncertainty and predictability issues cited above. Effectively, this results in the necessity to provide "backup" ancillary services resources, similar to what is necessary to insulate the grid from variability in renewables generation.
- The paper cites a FERC study indicating that potentially 19% of all load could involve some level of DR by 2020 (about 2.5x larger than current levels of DR participation.) This suggests an added driver of operational flexibility in the generation fleet in the future, beyond increased generation from renewables.

24. ***Heterogeneous Unit Clustering for Efficient Operational Flexibility Modeling for Strategic Models***, Bryan S. Palmintier and Mort D. Webster, MIT, ESD-WP-2013-04, January 2013

Synopsis

This paper addresses modeling approaches necessary for integrating analysis of future generation fleet composition with unit commitment analysis. In particular, the paper shows that aggregated representation of different sub-groups of generation resources brings tremendous benefits in terms of computation time while sacrificing little in terms of numerical accuracy of modeling metrics.

Relevance to This Project

This paper was included for review because it directly validates a modeling strategy utilized in the US-REGEN analyses performed for the DOE FT project.

Summary of Key Insights and/or Data

- The paper shows that aggregation (referred to in the paper as "heterogeneous unit clustering", abbreviated here as HUC) improves runtimes with acceptable trade-offs for accuracy in various metrics, even in light of the necessity of assigning the same operation conditions and assumptions to all units in a given cluster.
- The benefit HUC is that it greatly reduces the dimensionality of the unit commitment analysis (as opposed to treatment of each individual generation asset with its own unique state and operational limitations.)
- The paper also discusses the underlying mathematics related to an efficient approach to accomplishing HUC.
- The paper tests several variations of HUC on a test system containing 205 generation units (a simplified version of the ERCOT system) for a sample week. Results indicated reduced analysis times by roughly 400x, while limiting error in metrics for CO_2 emissions, energy mix, and dispatch schedule to a range of 0.05-0.2%.

25. ***Impact of Cycling on the Operation and Maintenance Cost of Conventional and Combined Cycle Power Plants***, 2013, EPRI 3002000817

Synopsis

This report was produced in collaboration with ETD in the UK. The report provides information that informs assumptions about O&M cost assumptions relating to future flexible operations. The contractor, ETD, provides a completely different source of data than APTECH, who was involved in most of the previous NREL studies. Both ETD and APTECH use a "top-down" statistical approach to analyzing reliability, availability, and non-fuel costs associated with cycling (starts) for coal and gas CC assets.

Relevance to This Project

This report was of particular interest in that it represented work by an independent, international organization.

Summary of Key Insights and/or Data

- The report provides curve-fits and various correction factors that can be used to estimate availability and reliability over unit life for cycling vs baseload duty.
  - The data suggest significant drops in availability due to cycling, which increase with unit age (for both coal and combustion turbine combined cycle units).
  - This information was useful in information REGEN assumptions regarding reduced availability due to flexible operations.

- In addition, there are separate curve-fits on non-fuel O&M costs (which by their definition includes capital costs).
  - The data present costs as a function of equivalent hot starts (EHS)
  - The data suggest that as EHS exceed 400, the added O&M costs increase at a significantly higher rate.
- Lastly, the report includes start-up energy consumption models.

26. ***Impact of Minimum Load Operation on Steam Turbines***, EPRI, Palo Alto, CA: 2013, 3002001263

Synopsis

This report examines impacts of low turndown operations on steam turbines (which represents the entire existing coal fleet as well as the steam cycle in combustion turbine combined cycle units to some extent.) The report also looks at mitigation techniques to reduce negative impacts of low turndown on asset availability. In particular, the report focuses on avoiding steam turbine damage due to on/off operations (frequently referred to as "two shifting".)

Relevance to This Project

This report was chosen for review because insights to damage mechanisms and operational challenges inform the engineering assessment of generation and capacity factor variability results from the US-REGEN and unit commitment modeling in the DOE FT project.

Summary of Key Insights and/or Data

- The report notes that damages due to cycling are generally more severe than those associated with low turndown.
- The report summarizes experience for the existing fossil fleet relative to number of cycles and minimum loads; there is a very wide range of levels, suggesting that significant flexible operations are already occurring.
- The report discusses the impacts of the two main methods for achieving low turndown:
  - Fixed pressure, which entails maintaining boiler output and using valves to throttle steam to the turbine, or
  - Sliding pressure, which entails varying boiler operations to produce steam conditions associated with the desired level of output.
  - The fixed pressure approach enable more rapid ramping, but negatively impacts unit efficiency, while the sliding pressure approach has a less negative impact on efficiency, but ramp rates are more limited due to reliance on boiler operations.
- The report summarizes several design options that would enable more flexible operations. (Many of these options would require additional investment in existing units.)
- The report notes that there are potential water chemistry implications of flexible operations, e.g. changes in waterborne concentrations of different compounds via temperature-driven changes in the solubility of some compounds.

- The report notes that another potential challenge with sliding pressure operations is that if reheat temperature is not maintained, the phase transition zone in the turbine moves further upstream, potentially causing erosion in turbine stages not normally designed to operate w/wet steam.

27. ***Impact of Unit Commitment Constraints on Generation Expansion Planning with Renewables***, Palmintier, Bryan, and Mort Webster. IEEE, 2011. 1–7. Web.

Synopsis

This paper focuses on showing the inclusion of key details related to unit operations (e.g. ramping, low turndown) in generation expansion planning modeling substantially changes the resulting projected energy production and technology mix. The paper discusses a method for combining unit commitment and expansion planning analysis.

Relevance to This Project

As with the later 2013 paper by Palmintier, et al, this paper was chosen for review as it provides validation of the integrated approach taken in the DOE FT project by using US-REGEN and unit commitment modeling. This paper also addresses the value and necessity of such an integrated approach.

Summary of Key Insights and/or Data

- The paper shows that ignoring unit operational constraints in expansion planning models can result in a sub-optimal generation technology mix with significantly higher operation costs (~17%) and higher carbon emissions (~39%) with the potential of not meeting emissions targets.
- The methodology discussed in paper includes a major simplifying assumption, also used in US-REGEN, that a non-sequential, simplified load curve representation is permissible. The paper shows that this is an acceptable approach (which further validates the approach taken in US-REGEN.)
- The paper does an excellent job of explaining the necessity for key simplifying assumptions such as non-sequential, simplified load curve representation and aggregated generator representation, based the need to make modeling computationally tractable.
- This paper essentially presents preliminary work that subsequently led to the 2013 paper (separately reviewed in this literature review.)
- The paper shows that consideration of unit operational dynamics are even more important if higher levels of renewable generation and CO_2 emissions limits are present.
- The suggested methodology is tested via analysis of a simplified version of the ERCOT region.
- The paper recommends further research on the sensitivity of the integrated expansion planning/unit commitment analysis approach to presence of differing levels of hydro, RPS requirements, demand response and storage.

28. ***<u>Increasing the flexibility of coal-fired power plants</u>***, Henderson; IEA Clean Coal Centre, CCC/242, March 2014

<u>Synopsis</u>

This report concentrates on flexible operations challenges for coal-fired power plants. The report discusses detrimental consequences of flexible operations for boilers and steam turbines, and then potential options for increasing flexibility of these major systems. The report also looks at emissions control systems, auxiliary systems, control systems more briefly. This report is based on a survey and analysis of published literature.

<u>Relevance to This Project</u>

This report was chosen for review because it discusses potential approaches to enhance flexibility, which provides insights on assessing the existing and future fleet's capability to respond to increasing demand for flexible operations. The report considers insights from both the U.S. and internationally.

<u>Summary of Key Insights and/or Data</u>

- The report confirms issues and challenges related to flexible operations identified in other reports included in this literature review.
- The report discusses specific technical approaches to enabling flexible operations, although some may require significant capital investment.
- Relative to boiler operations, the report cited a number of design and/or operational concepts to enhance flexibility:
  - Extension of the acceptable fuel range. The report that this entails enabling biomass coal firing and fuel drying capabilities.
  - Potential used of indirect firing, describe in the report as additional of a pulverized coal hopper that allow fuel flow to the burner to be controlled independently of mill output.
  - Improved coordination of coal mill and burner system control. The report discusses several details of mill sizing and controls that could be optimized to support lower partial load and great load range.
  - Reduction of combustion chamber volume and height to facilitate faster load changes and higher efficiencies at partial loads.
  - Extending the primary and secondary control ranges over (over which design superheated and reheated steam parameters are maintained) such that lower minimum loads are possible. The report observes that achieving this involves matching steam and turbine metal temperatures (more easily done under sliding pressure operation.), and careful assessment of the design basis of key process conditions to determine if there is available design margin that would allow lower minimum load.
- The report also notes that future technological capabilities like advanced materials enabling smaller wall thicknesses for pressure parts will enable higher thermal transients to be sustained (this has also been noted in research that EPRI is conducting as part of a

separate major DOE project on materials for advanced ultrasupercritical (AUSC) coal units.

- The report also discusses potential design features of new coal plants that would significantly help flexible operations.
- As part of supporting background research, the report notes that a meta-analysis of published literature suggests the following minimum start up times for coal units: 12 hours (cold start); 4 hours (warm start); 1 hour (hot start), albeit with significant variance.
- The report discusses several features of turbine design and operations essential to enabling flexible operations:
  - Maintenance of clearances between stationary and moving components to small tolerances throughout flexible operations, resulting in a need for potentially improved design, advanced sealing, and measures for ensuring uniform thermal loading, particularly during cold starts.
  - Turbine bypass systems, enabling management of turbine steam temperature during boiler startup and shutdown.
  - Potential use of steam cooling of the outer casing to maintain its temperature lower than that of the inner casing during load changes, which potentially could avoid outer casing temperature extremes, thus permitting reduced thickness in design and reduction of cold start up time.
- The report discusses sliding pressure operations, as is done in other reports included in this literature review.
- The report notes that thermal storage systems for low or high pressure feedwater systems could enhance ramp rates, lower minimum load, and capability for frequency control via more rapid response.
- The report cites several papers and existing units where some of the above strategies and design features have been used.
- It is not clear, however, whether data presented in the report related to startup times, minimum load, etc. considered added limitations resulting from environmental controls. The report does present some discussion of the sensitivity of these systems to operational transients, but this discussion is separated from that focusing on enhancing flexible operations.

29. ***Modeling and Evaluation of Iowa Hill Pumped-Hydro Storage Plant: Value in MSUD and in Larger Region***, Brownell, G. (SMUD), et al; Tuohy, A. (EPRI), et al, December 2013

Synopsis

This report was prepared to examine the benefits of a particular proposed pumped storage facility in California referred to as the Iowa Hill Pumped Hydro Storage Plant in light of increasing generation from renewables. The report involved modeling several different scenarios different levels of renewable generation for the Sacramento Municipal Utility District (SMUD) balancing area and for the entire Western Interconnection. The report relied on unit commitment analysis to assess the value of pumped hydro in the context of the above scenarios. An EPRI energy storage evaluation tool was used to analyze results of the unit commitment analysis to yield an assessment of pumped hydro value for various applications, e.g. resource adequacy, transmission deferral, etc. The report also looked at benefit of the proposed pumped hydro facility to management of the Upper American River watershed (e.g. reservoir management, spillage reduction, etc.)

Relevance to This Project

This report was included in the scope of the review because it is one of view that looks at energy storage, particularly pumped hydro.

Summary of Key Insights and/or Data

- The report shows a range of values for the financial benefits of pumped hydro under different scenarios, but overall concludes that increasing renewable generation increases the value of pumped hydro (as represented by this specific proposed facility.)
- The report concludes that if the pumped hydro facility were variable speed, its projected value would be at least 1/3 larger, and possibly 2x larger.
- The report concluded that cycling of firm assets resulting from increasing renewable generation was decreased significantly if the pumped hydro asset were available.
- Emissions impacts were more variable, depending upon the scenario.
- Finally, the report concluded that reciprocating engines as an alternative to pumped hydro were likely to be significantly less valued.
- This report suggests that future inclusion of pumped hydro as a technology option in expansion planning modeling would be valuable.

30. ***Primer on Flexible Operations in Power Plants***, 2013, EPRI 3002000045

Synopsis

This EPRI white paper provides an overview of flexible operations mode and impacts. It includes a historical review of duty cycles of fossil assets.

Relevance to This Project

This white paper was reviewed as it serves as a useful summation of historical trends in fossil unit operational modes.

Summary of Key Insights and/or Data

- The white paper describes flexible operations in terms of 7 different modes:
  - Two-shifting (daily startup/shutdown)
  - Double two-shifting (2x/day startup/shutdown)
  - Minimum load operations
  - Weekend shutdown

- Load following
- On-load cycling (daily baseload + nightly minimum load)
- Sporadic operations (prolonged periods of shutdown between operational periods)

- The white paper shows charts summarizing data from EPRI, APTECH, and ETD (European organization) showing increased equipment damage as a function of increasing number of cold starts.
- The white paper provides a summary of cycling damage mechanisms identified in prior EPRI research.
- The white paper shows that scope and frequency of cycling has increased through trends in estimated forced outage rates between 1984 and 2003.
- The white paper also summarizes other effects of increased cycling (e.g. increased heat rate, etc.) as well as potential mitigation strategies, many of which require moderate to significant investment in existing or new equipment.

31. ***Reducing power plant derates, emissions, profit loss, and equipment damage from cycling and load-following***, Richards, G., NETL, 2012

Synopsis

This paper, by NETL, was a proposal to utilize a simulation approach to identifying cycling damage and mitigation strategies through use of a prototype natural gas combined cycle simulator. The proposed approach was to use simulation to adjust design and operational approaches in response to known issues associated with cycling, e.g. poorly controlled attemperator sprays, which exacerbate thermal cycling.

Relevance to This Project

Although a proposal rather than completed research, this paper was reviewed from the perspective of potentially informing future research needs that will be discussed in the DOE FT project final report.

Summary of Key Insights and/or Data

- The NETL simulator (as of the date of this paper) was configured to model a 574 MW 2 on 1 natural gas combined cycle. The paper also noted that at that time, NETL had signed a cooperative research and development agreement with Invensys Operations Management to develop, test and deploy a dynamic simulator and operator training system for a generic once-through pulverized coal plant.
- The potential value of simulation would the ability to explore the impact of mitigation strategies on flexible operations impacts, results of which could guide further research.
- The paper also suggests that a further enhancement to simulation would be integration with economic evaluation, e.g. the Intertek-APTECH real-time cost tool for analysis of cost of anticipated ramp rates.

32. ***The Power of Transformation: Wind, Sun and the Economics of Flexible Power Systems***, International Energy Agency, 2014

Synopsis

This International Energy Agency report focuses on the questions of whether an electric system with high levels of renewable generation can simultaneously provide a secure grid and a low-carbon energy system, and at what cost. The report is based on analysis of 7 case studies comprising 15 countries.

Relevance to This Project

This report was included for review as it is a major international study of several countries under different scenarios. Although assumption on which the report is based differ substantially from those used in the DOE FT project, the report highlights many of the same issues that must be addressed in the DOE FT project.

Summary of Key Insights and/or Data

- The report provides relatively general conclusions that are conditional on a significant number of important assumptions.
- The modeling basis contains many key assumptions which may not be broadly valid
  - Island grid, no inter-regional energy exchanges
  - Assumed availability of storage
  - Short assumed nuclear, coal and gas asset lifetimes (40, 30, and 20 years, respectively)
  - Unit commitment analysis limited to a selected 4 week interval
  - Apparent assumptions of a generation fleet whose total capacity remains fixed, yet adequate reserve margin is available at all times.
- Report recommendations seem to implicitly assume centralized grid and generation fleet planning (clearly not the case in many regions in the world, particularly the U.S.)
- The report does not seem to significantly address additional challenges associated with flexible operations with a wide array of emissions controls (including CO_2 capture.)
- The report provides the following conclusions
  - A power system with renewable generation share of 45% could come at little additional cost over a system with no renewables at all.
  - Variable resource integration is not a large challenge if key caveats are met: no locally high concentrations of variable resources, ensuring that variable resources can contribute to grid stabilization when needed, and coordination of variable generation resource forecasts with operation of other generation assets and power flows on the grid. These caveats are substantial assumptions that well may not be met in many cases.
  - The effects of variable generation become apparent at penetrations above 2-3%.

- – The additional costs of more flexible operations of existing power plants are not an important element in increased costs.
- – Long-term planning and deployment of variable resources must be integrated into overall resource planning, otherwise these resources may be deployed faster than necessary transmission and generation infrastructure needed to support them. The report cites the example of competitive renewable energy zones (CREZ) in Texas (but note that Texas is not typical of most other U.S. regions in terms of grid characteristics.)
- – System service markets need to price operational flexibility at its value to ensure that planning and asset management reflect operational flexibility needs and priorities.
- – As with many other reports, the report concludes that increasing variable generation corresponds to increasing demand for flexible operations for other generation assets.
- – The report notes the importance of considering variable resources within the overall context of an entire system over time, accounting for capacity, generation, and transmission needs. The approach taken in the DOE FT projects addresses this issue.
- – The report recommends that transmission system development be facilitated in general terms.

33. ***The Spanish Experience in Electric Generation Capacity Turnover***, December 2009, EPRI 1020592

Synopsis

This report summarized developments in generation, natural gas infrastructure, wind power and responses to swings in renewable generation, and provision of operating reserves in Spain. It included projections of added generation out to 2020 with particular attention to impacts on capacity utilization for coal and natural gas combined cycle units.

Relevance to This Project

This report was included in the scope of the literature review because it represents an international, as opposed to U.S.-centric, analysis.

Summary of Key Insights and/or Data

- The report provides several projections related to generation and grid infrastructure, but given that it was written just after the beginning of the great global recession in the late 2000s, many of these conclusions would likely change.
- Generally, the report projected significant growth in wind and solar generation, with relatively constant future generation shares for natural gas combine cycle (NGCC), coal, hydro, and nuclear. The report projected a generation fleet in 2020 in which 40% of capacity would be renewable.
- The report showed that capacity factors for coal and NGCC units had already been steeply declining and were projected to fall below an average of 40% by 2020.
- The report notes that several complexities in the Spanish electricity market and subsequent impacts on generation planning resulted from several government policies.

- The report suggests that Spain is most similar to the ERCOT region in the U.S., in terms of generation mix, total consumption, and renewable generation share.

34. ***Unit Operational Flexibility: Low-Load Turndown of a Large Supercritical Boiler***, EPRI, Palo Alto, CA: 2013, 3002002087

    Synopsis

    This EPRI report focuses on effects of low turndown and sliding pressure operations on boiler tube reliability. The report explored in more quantitative terms these effects, e.g. in terms of tube superheat temperatures. The research underlying the report accomplished this through instrumenting a large power plant boiler to monitor boiler tube temperature distributions, with the goal of anticipating where tube damage might occur.

    Relevance to This Project

    This report was selected for review because it investigates in detail a major aspect of flexible operations, e.g. low turndown operations. Understanding this particular operational mode and its potential effects informed the engineering assessment of modeling results in the DOE FT project.

    Summary of Key Insights and/or Data

    - The report's results are based on testing at the Tennessee Valley Authority's Cumberland Unit 1 (a supercritical coal-fired unit). Boiler tube temperatures were monitored as unit output was reduced in the case of full pressure and reduced pressure operations.
    - The report observes that when the primary superheater operated at full pressure, but the secondary superheater was transitioned to sub-critical conditions, a subset of the tubes in the secondary superheater outlet experienced very high temperatures. (This suggests that many units that may employ sliding pressure to achieve low turndown may increase probabilities for tube damage, which may ultimately affect unit availability.)
    - The report concluded that further research is needed into the potential effects of a mixture of tubes, some experiencing high temperatures and others experiencing normal or low temperatures.
    - The report notes that historically, coal assets were generally designed for baseload operations, as opposed to the array of flexible operations modes discussed in several reports included in this literature review.

The report provides several recommendations for mitigating potential damage associated with low turndown, some related to design and others related to operational strategies.

C
HEAT MAP RESULTS

As described in Section 3.3.5, heat maps for generation variability and capacity factor were produced based on data from the unit commitment analysis. Section 4.2.3 provides an overview of key results from the unit commitment analysis and the associated engineering assessment. This appendix provides a comprehensive summary of the heat maps for all of the different generation technology/scenario/analysis year combinations.

In total, there are 90 heat maps depicting average hourly generation output variability:

- Two sets of unit commitment analysis outputs, one based on Texas (TX) as the region modeled with unit level detail and the other based on the Northwest Central (NWC) region modeled with unit level detail.
- Three analysis years: 2015, 2025, and 2050.
- 4 scenarios (reference, low natural gas price trajectory, high natural gas price trajectory, high natural gas price trajectory +no transmission expansion). For 2015, there are heat maps only for the reference scenario as this is the starting year for all scenarios.
- 5 different generation technologies: natural gas combined cycle, coal, nuclear, combustion turbines, and regional import. While the latter isn't a technology, in terms of unit commitment, understanding variability in imports is an important component of understanding the impact of increased demand for generation flexibility.

In total, there are 72 heat maps depicting average hourly generation capacity factor:

- Two sets of unit commitment analysis outputs, one based on Texas as the region modeled with unit level detail and the other based on the Northwest Central region modeled with unit level detail.
- Three analysis years: 2015, 2025, and 2050
- 4 scenarios (reference, low natural gas price trajectory, high natural gas price trajectory, high natural gas price trajectory +no transmission expansion). For 2015, there are heat maps only for the reference scenario as this is the starting year for all scenarios.
- 4 different generation technologies: natural gas combined cycle, coal, nuclear, and combustion turbines.

Generation Variability Heat Maps – 2015 – Reference Scenario (detailed UC Region=TX)

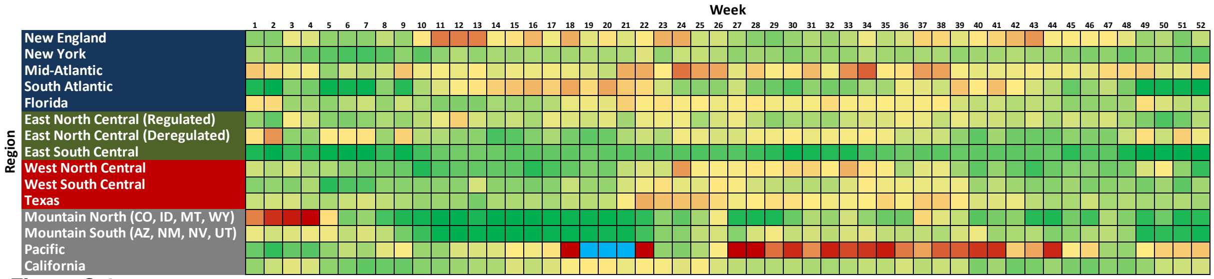


Figure C-1
Generation Variability – 2015 – Reference Scenario – Natural Gas Combined Cycle

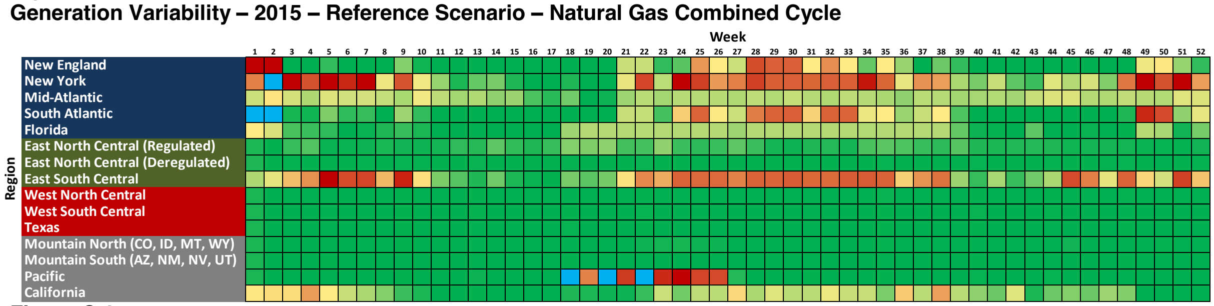


Figure C-2
Generation Variability – 2015 – Reference Scenario – Coal

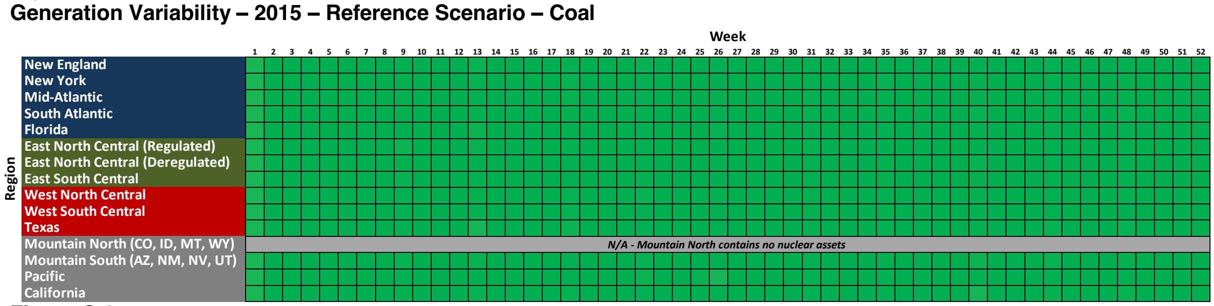


Figure C-3
Generation Variability – 2015 – Reference Scenario – Nuclear

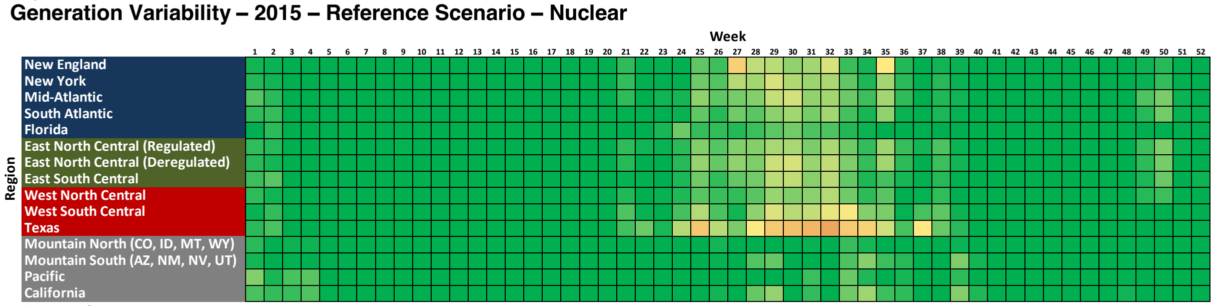


Figure C-4
Generation Variability – 2015 – Reference Scenario – Combustion Turbine

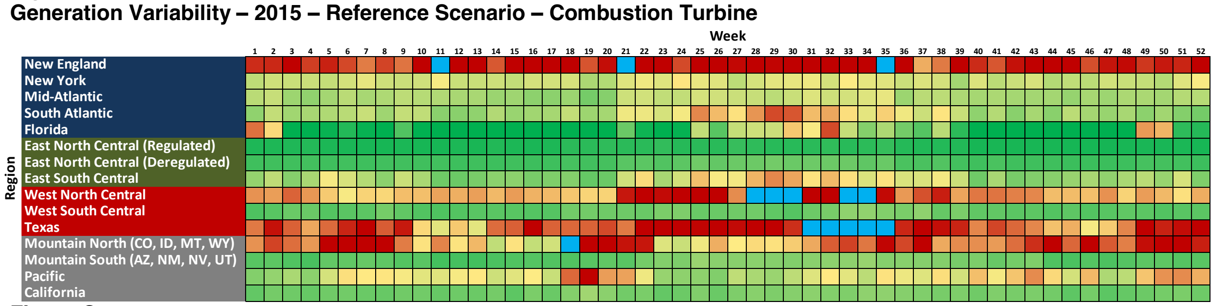


Figure C-5
Generation Variability – 2015 – Reference Scenario – Imports

Generation Variability Heat Maps – 2015 – Reference Scenario (detailed UC Region=NWC)

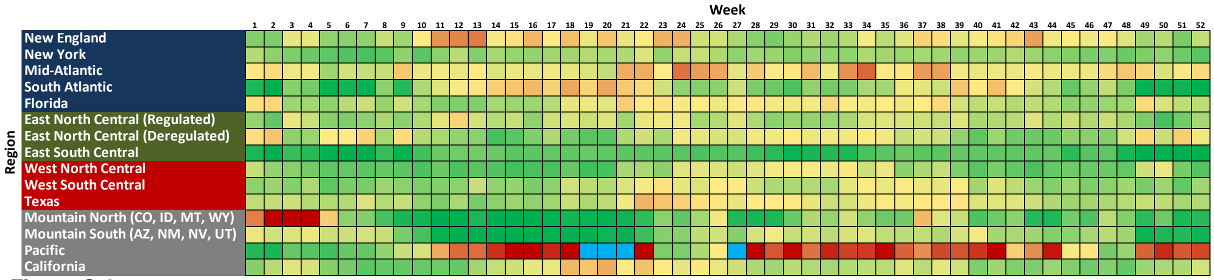


Figure C-6
Generation Variability – 2015 – Reference Scenario – Natural Gas Combined Cycle

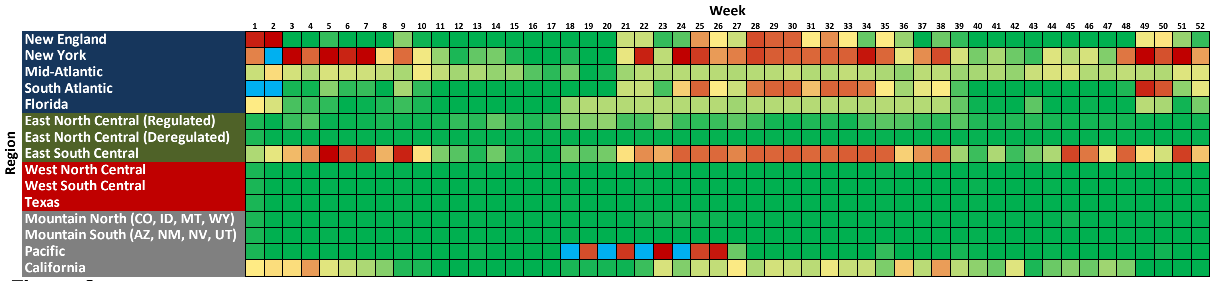


Figure C-7
Generation Variability – 2015 – Reference Scenario – Coal

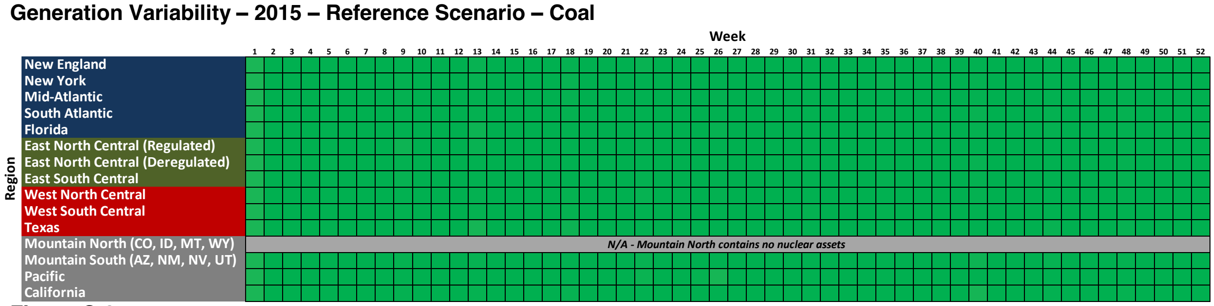


Figure C-8
Generation Variability – 2015 – Reference Scenario – Nuclear

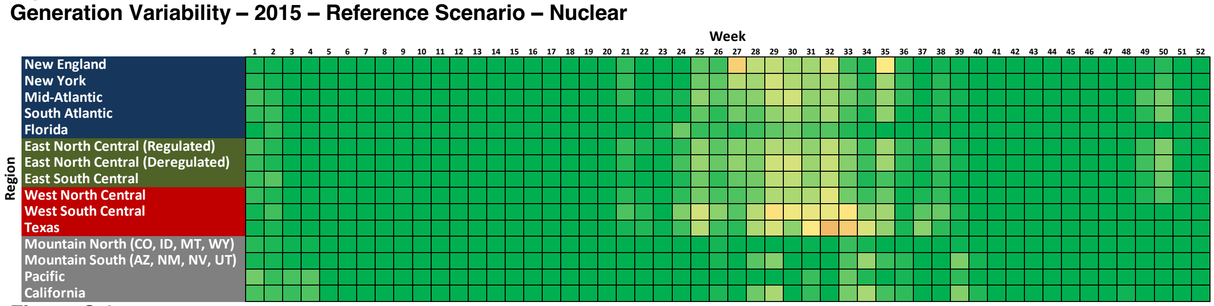


Figure C-9
Generation Variability – 2015 – Reference Scenario – Combustion Turbine

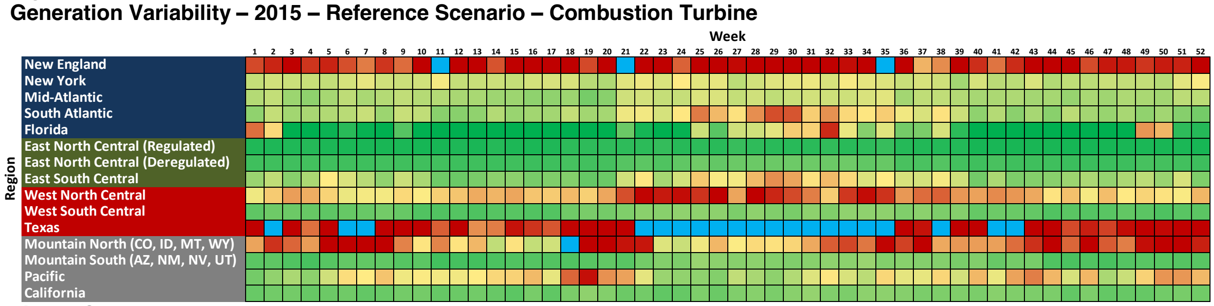


Figure C-10
Generation Variability – 2015 – Reference Scenario – Imports

Generation Variability Heat Maps – 2025 – Reference Scenario (detailed UC Region=TX)

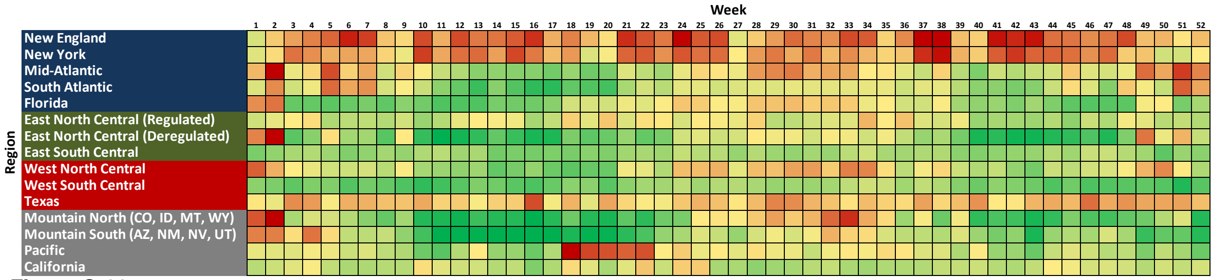


Figure C-11
Generation Variability – 2025 – Reference Scenario – Natural Gas Combined Cycle

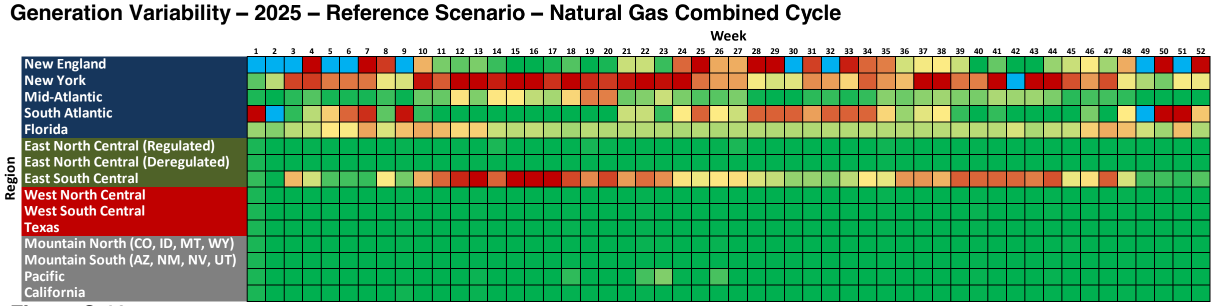


Figure C-12
Generation Variability – 2025 – Reference Scenario – Coal

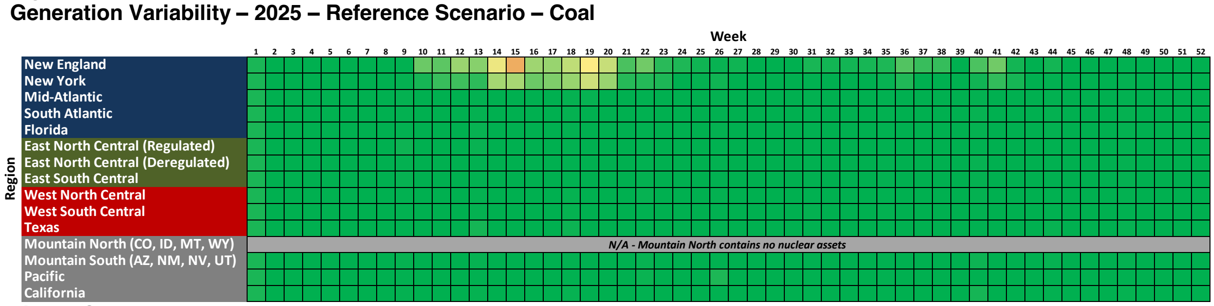


Figure C-13
Generation Variability – 2025 – Reference Scenario – Nuclear

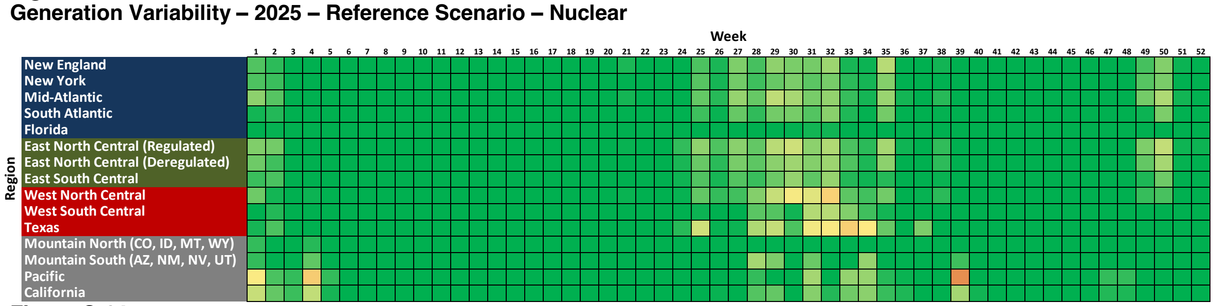


Figure C-14
Generation Variability – 2025 – Reference Scenario – Combustion Turbine

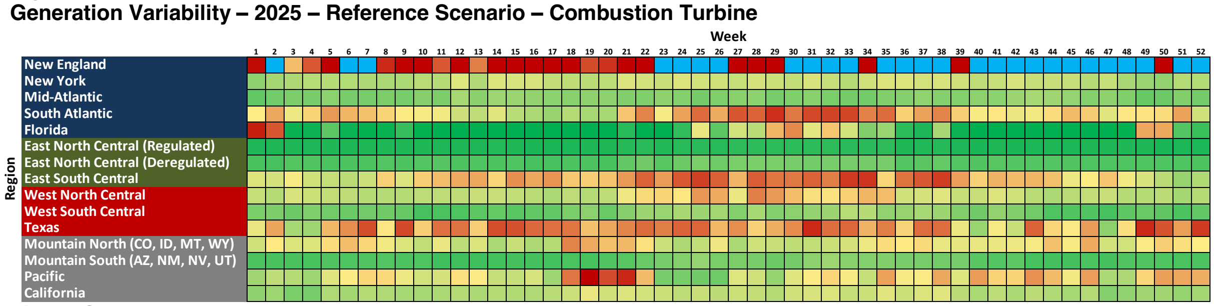


Figure C-15
Generation Variability – 2025 – Reference Scenario – Imports

Generation Variability Heat Maps – 2025 – Reference Scenario (detailed UC Region=NWC)

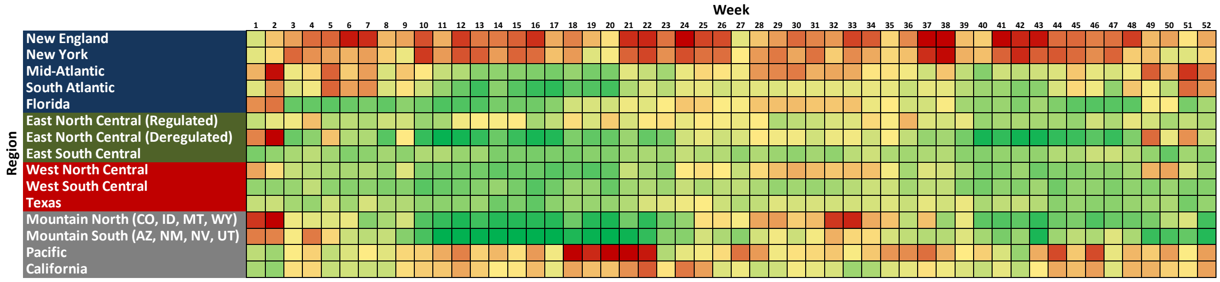


Figure C-16
Generation Variability – 2025 – Reference Scenario – Natural Gas Combined Cycle

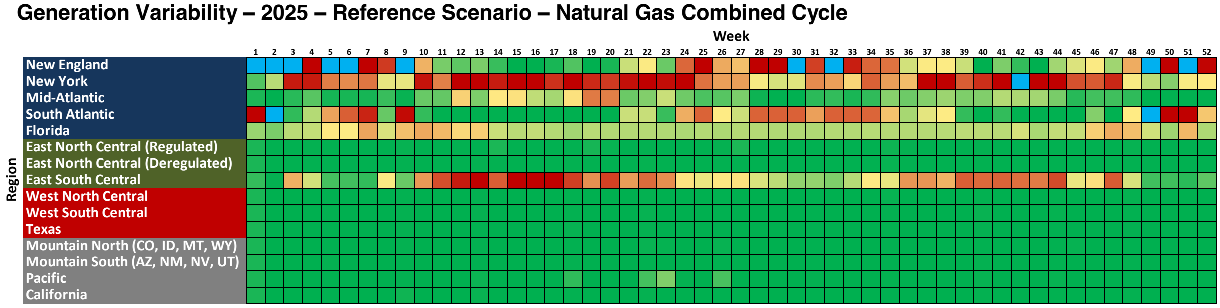


Figure C-17
Generation Variability – 2025 – Reference Scenario – Coal

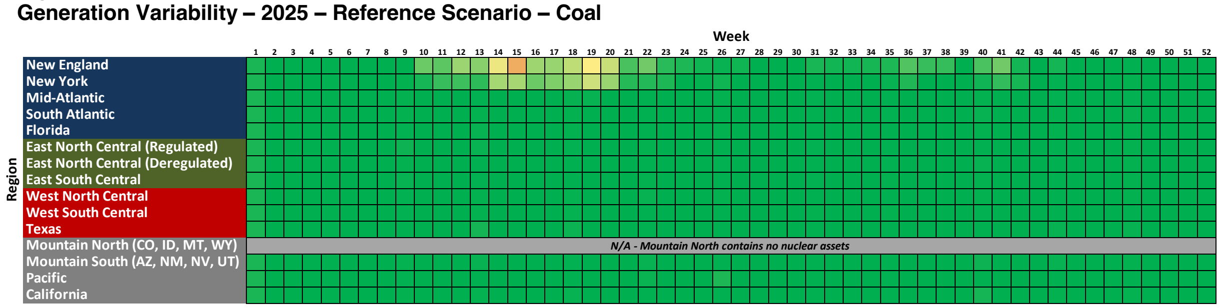


Figure C-18
Generation Variability – 2025 – Reference Scenario – Nuclear

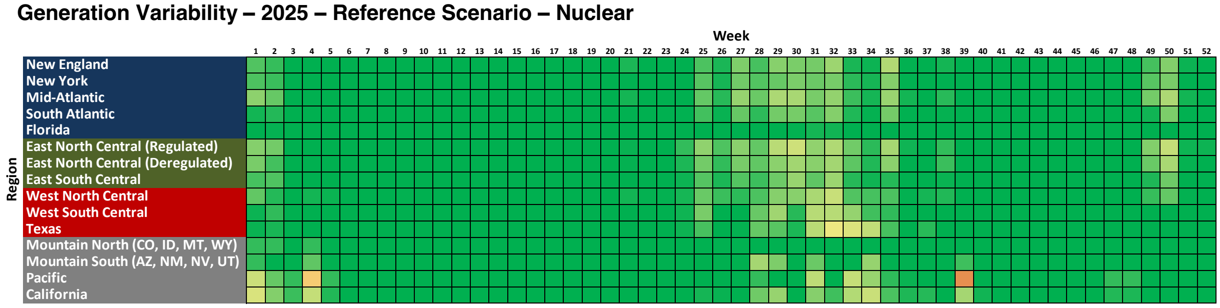


Figure C-19
Generation Variability – 2025 – Reference Scenario – Combustion Turbine

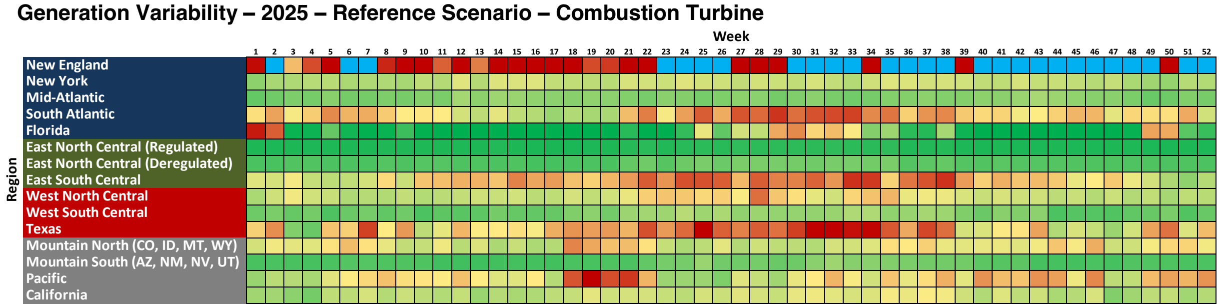


Figure C-20
Generation Variability – 2025 – Reference Scenario – Imports

Generation Variability Heat Maps – 2050 – Reference Scenario (detailed UC Region=TX)

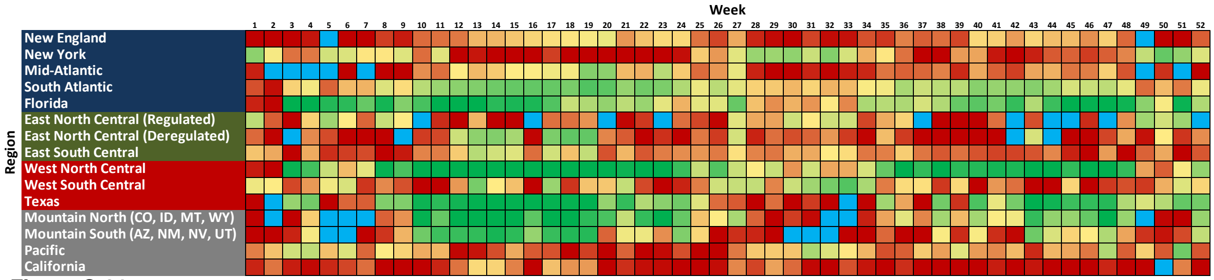


Figure C-21
Generation Variability – 2050 – Reference Scenario – Natural Gas Combined Cycle

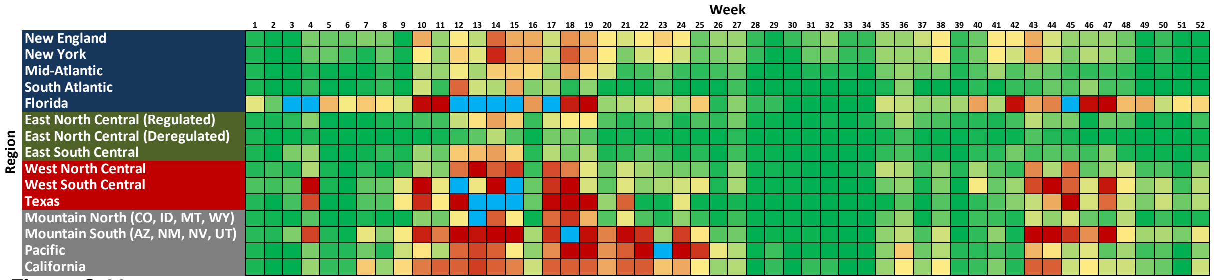


Figure C-22
Generation Variability – 2050 – Reference Scenario – Coal

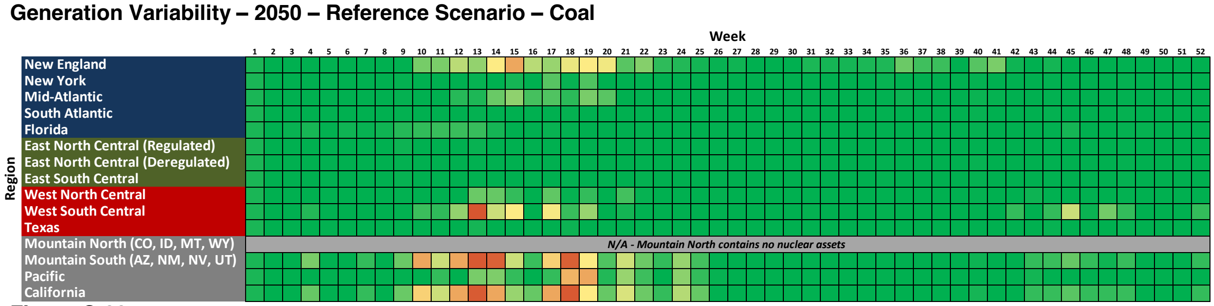


Figure C-23
Generation Variability – 2050 – Reference Scenario – Nuclear

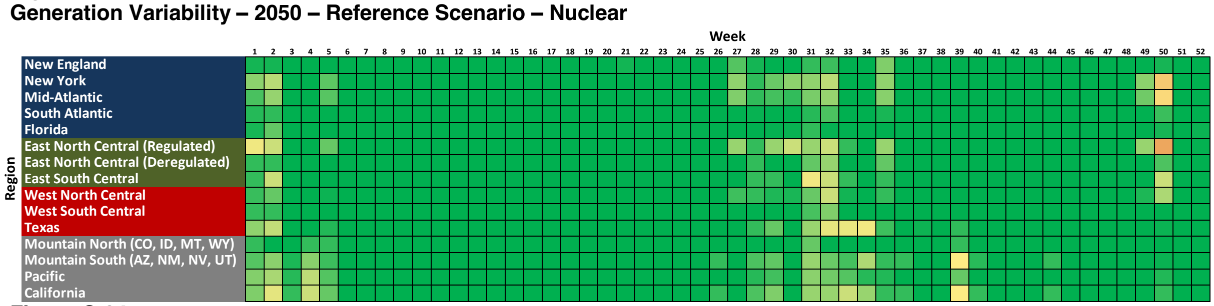


Figure C-24
Generation Variability – 2050 – Reference Scenario – Combustion Turbine

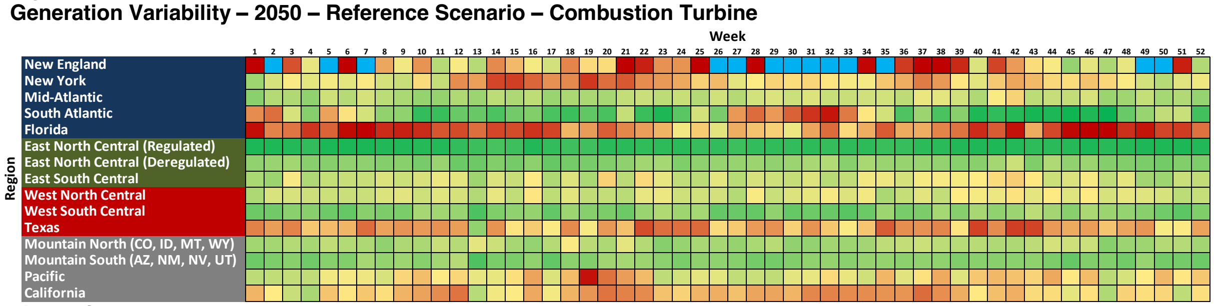


Figure C-25
Generation Variability – 2050 – Reference Scenario – Imports

Generation Variability Heat Maps – 2050 – Reference Scenario (detailed UC Region=NWC)

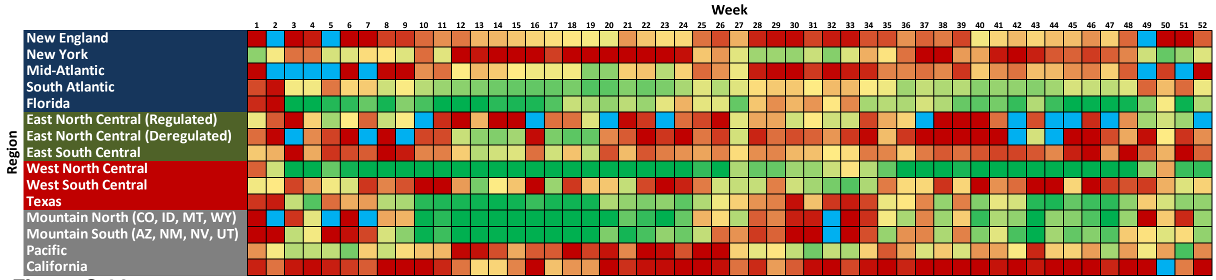


Figure C-26
Generation Variability – 2050 – Reference Scenario – Natural Gas Combined Cycle

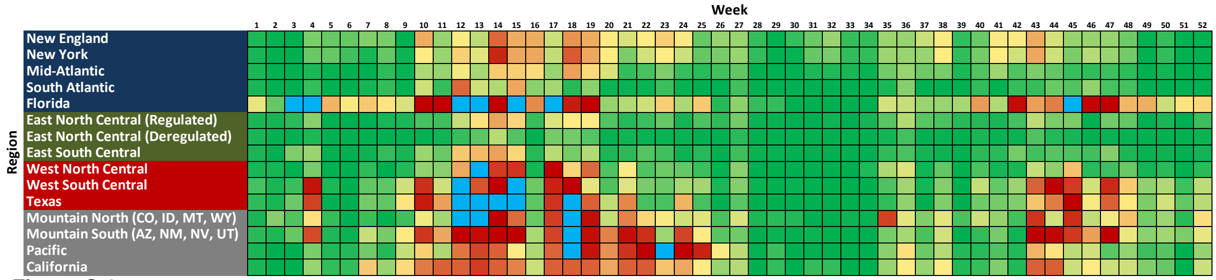


Figure C-27
Generation Variability – 2050 – Reference Scenario – Coal

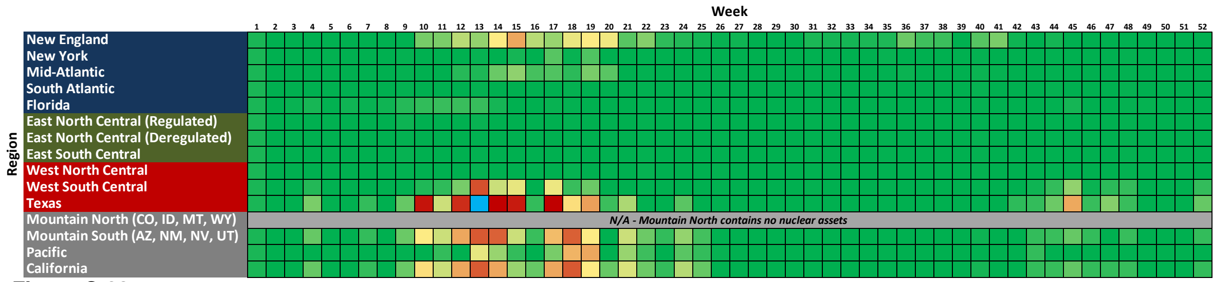


Figure C-28
Generation Variability – 2050 – Reference Scenario – Nuclear

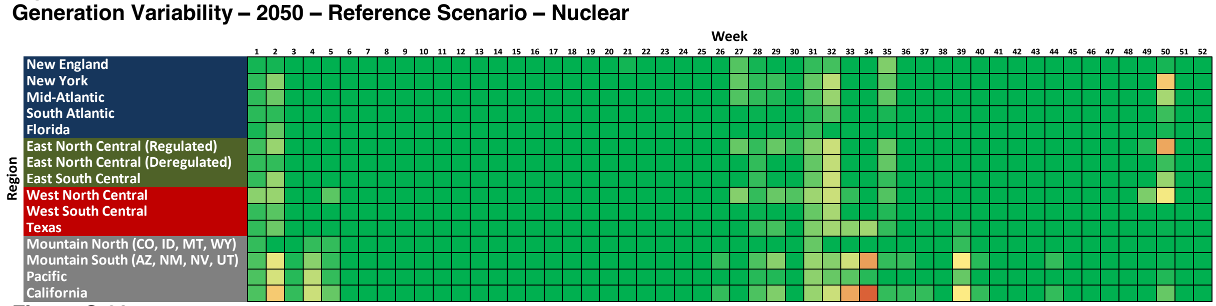


Figure C-29
Generation Variability – 2050 – Reference Scenario – Combustion Turbine

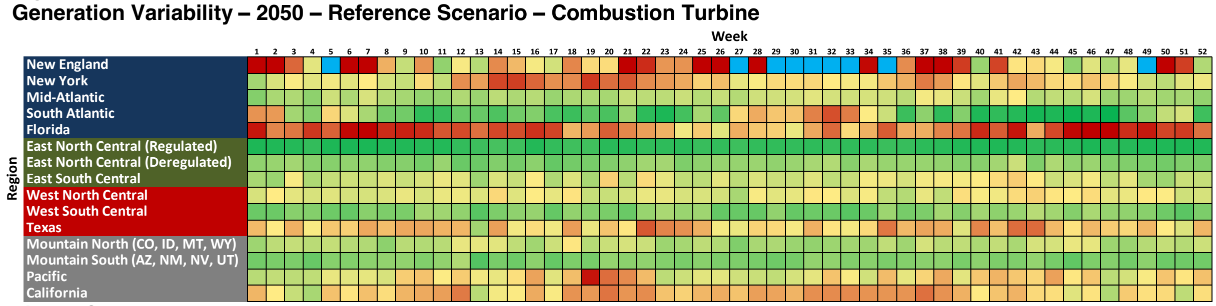


Figure C-30
Generation Variability – 2050 – Reference Scenario – Imports

Generation Variability Heat Maps – 2025 – Low Gas Price Scenario (detailed UC Region=TX)

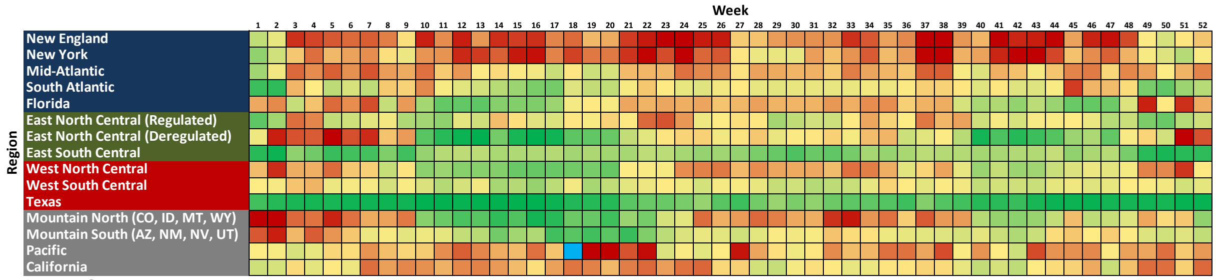


Figure C-31
Generation Variability – 2025 – Low Gas Price Scenario – Natural Gas Combined Cycle

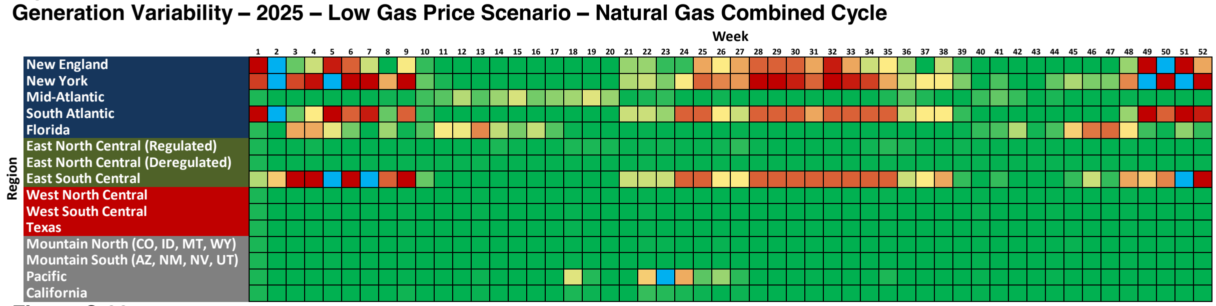


Figure C-32
Generation Variability – 2025 – Low Gas Price Scenario – Coal

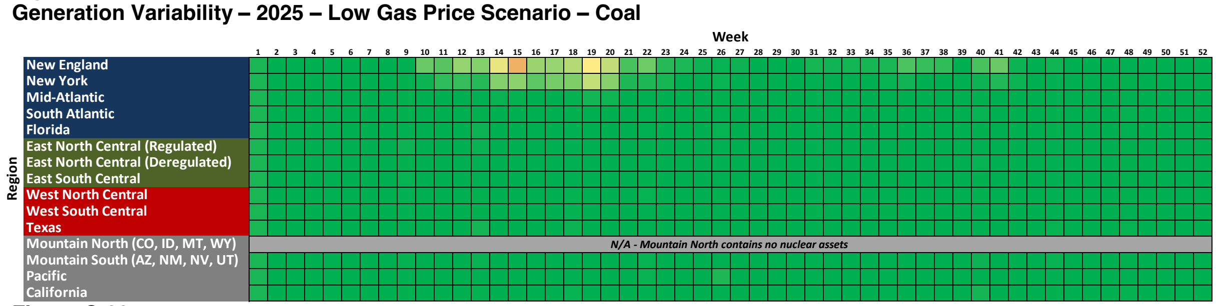


Figure C-33
Generation Variability – 2025 – Low Gas Price Scenario – Nuclear

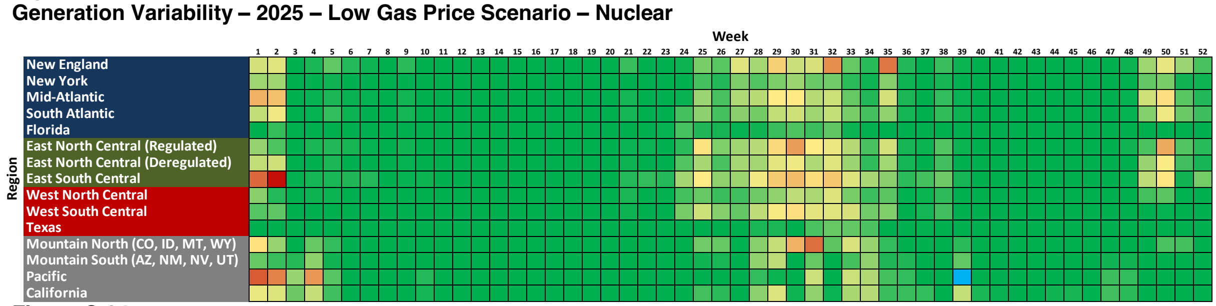


Figure C-34
Generation Variability – 2025 – Low Gas Price Scenario – Combustion Turbine

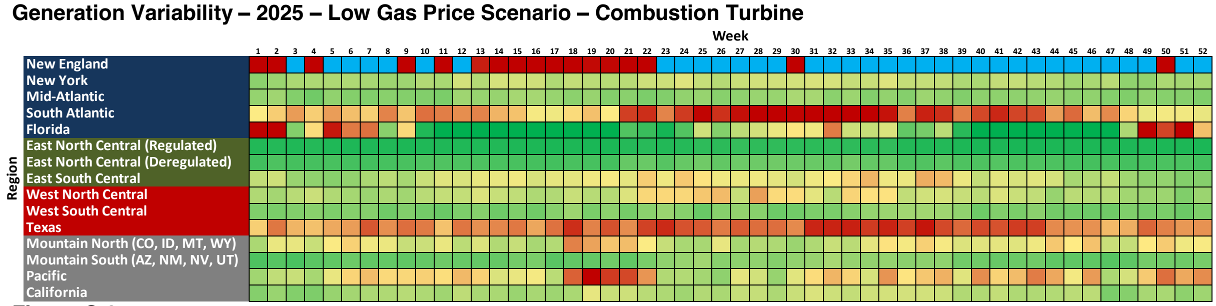


Figure C-35
Generation Variability – 2025 – Low Gas Price Scenario – Imports

Generation Variability Heat Maps – 2025 – Low Gas Price Scenario (detailed UC Region=NWC)

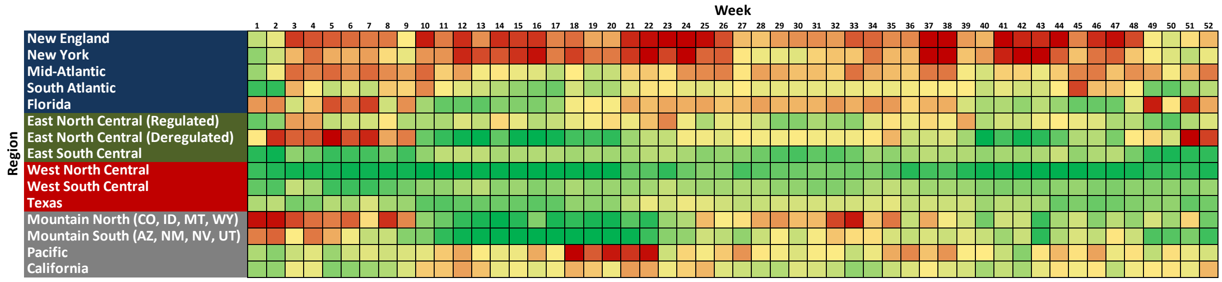


Figure C-36
Generation Variability – 2025 – Low Gas Price Scenario – Natural Gas Combined Cycle

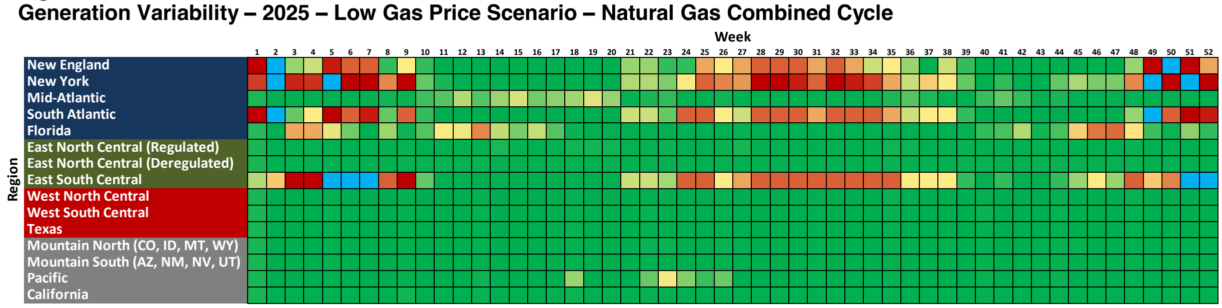


Figure C-37
Generation Variability – 2025 – Low Gas Price Scenario – Coal

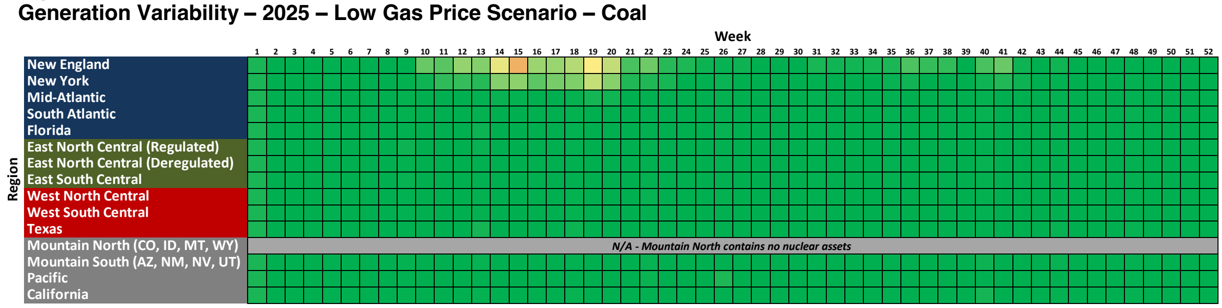


Figure C-38
Generation Variability – 2025 – Low Gas Price Scenario – Nuclear

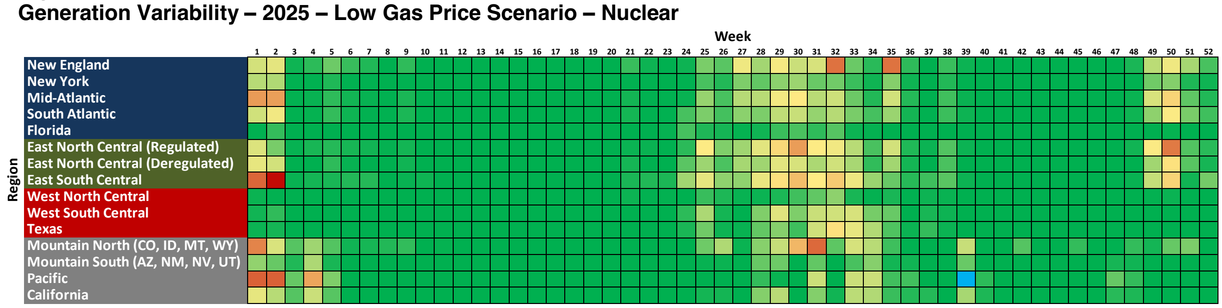


Figure C-39
Generation Variability – 2025 – Low Gas Price Scenario – Combustion Turbine

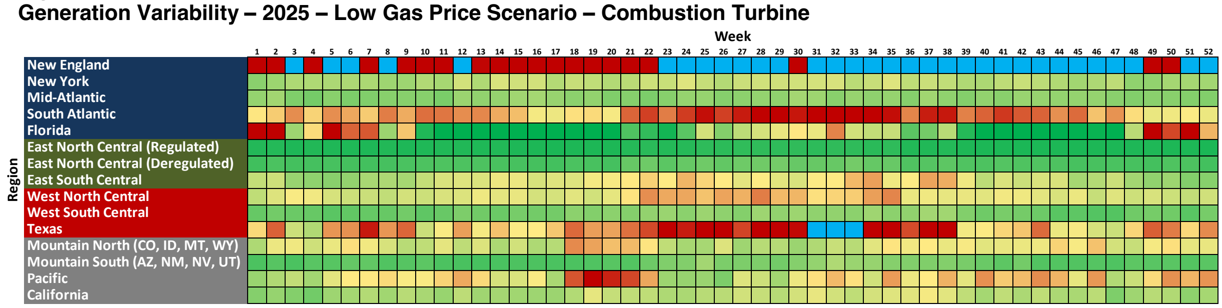


Figure C-40
Generation Variability – 2025 – Low Gas Price Scenario – Imports

Generation Variability Heat Maps – 2050 – Low Gas Price Scenario (detailed UC Region=TX)

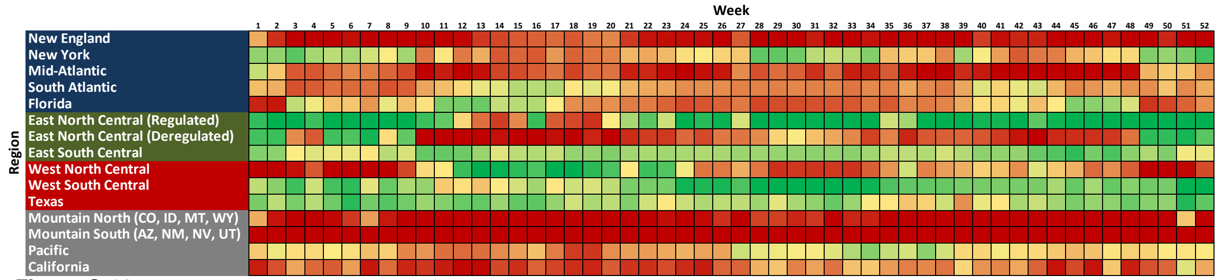


Figure C-41
Generation Variability – 2050 – Low Gas Price Scenario – Natural Gas Combined Cycle

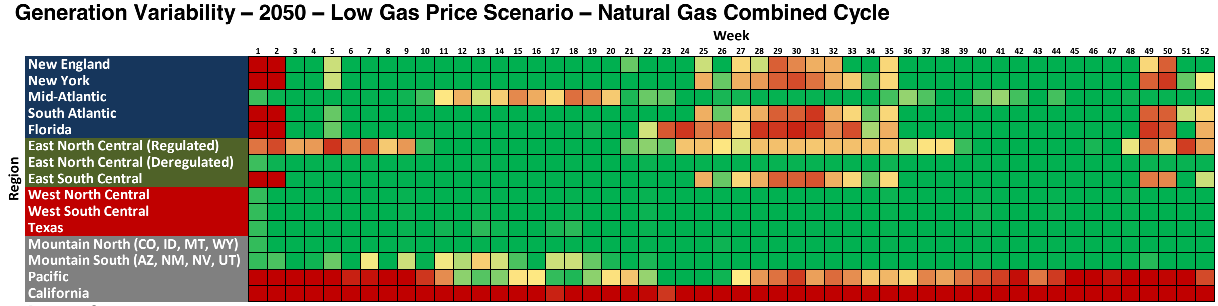


Figure C-42
Generation Variability – 2050 – Low Gas Price Scenario – Coal

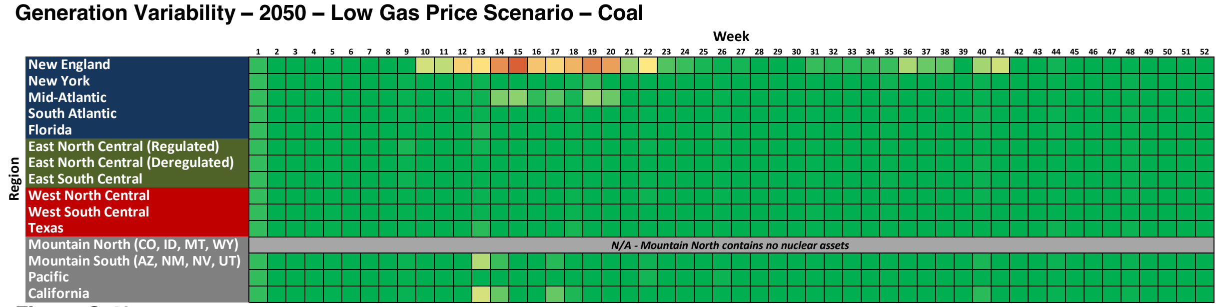


Figure C-43
Generation Variability – 2050 – Low Gas Price Scenario – Nuclear

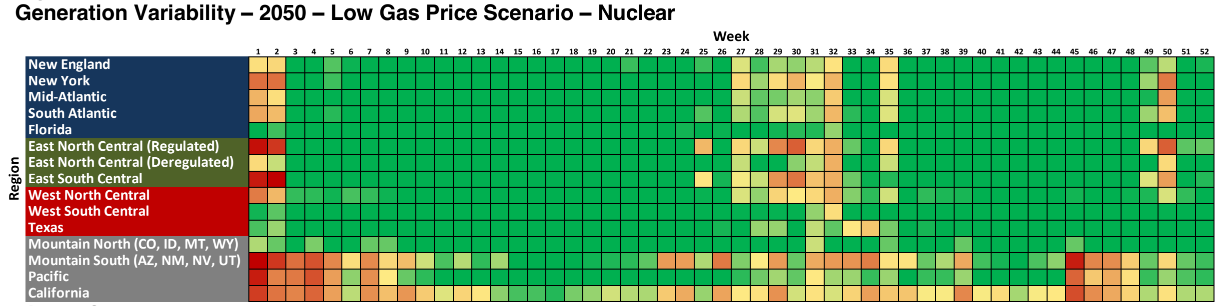


Figure C-44
Generation Variability – 2050 – Low Gas Price Scenario – Combustion Turbine

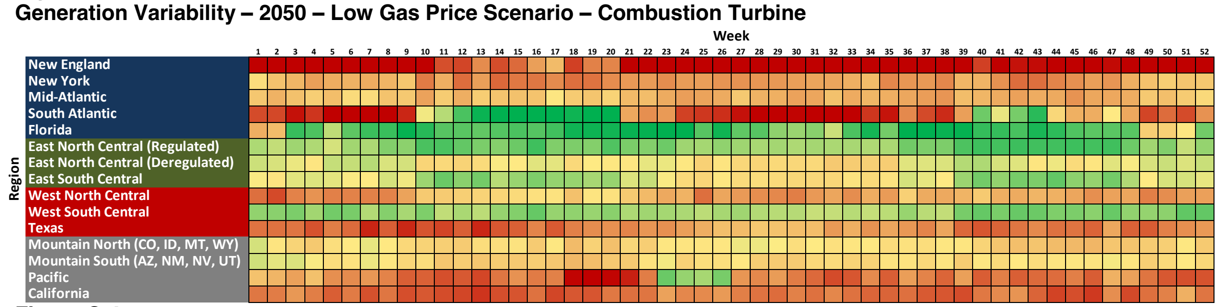


Figure C-45
Generation Variability – 2050 – Low Gas Price Scenario – Imports

Generation Variability Heat Maps – 2050 – Low Gas Price Scenario (detailed UC Region=NWC)

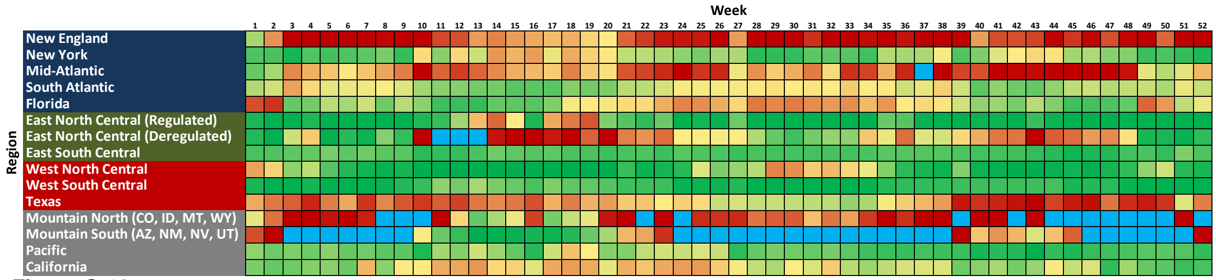


Figure C-46
Generation Variability – 2050 – Low Gas Price Scenario – Natural Gas Combined Cycle

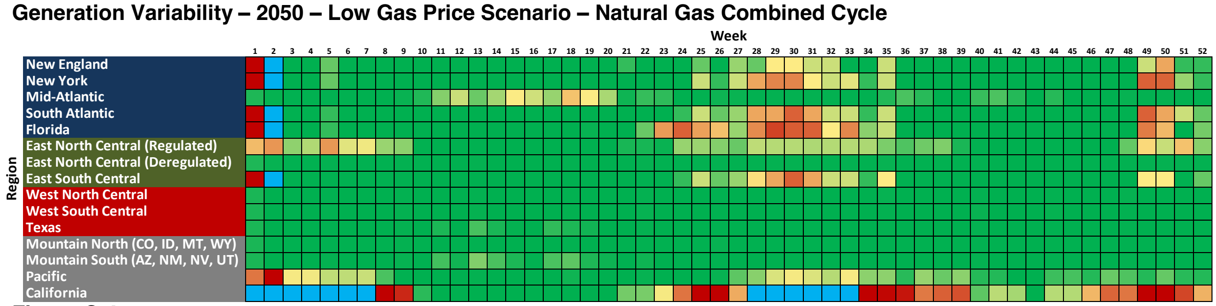


Figure C-47
Generation Variability – 2050 – Low Gas Price Scenario – Coal

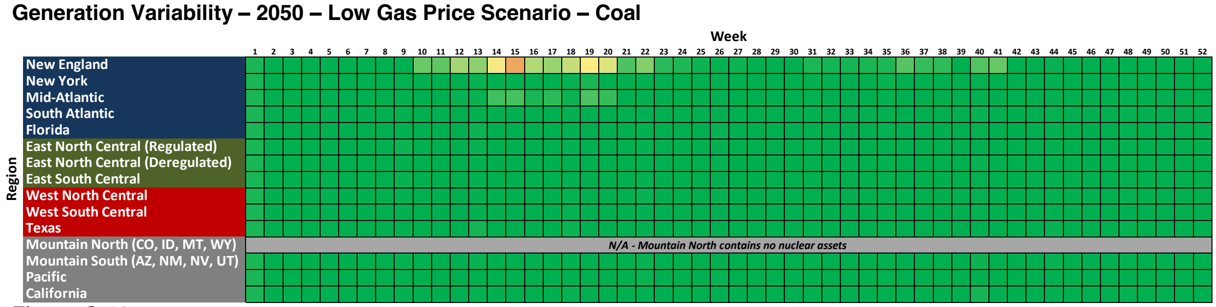


Figure C-48
Generation Variability – 2050 – Low Gas Price Scenario – Nuclear

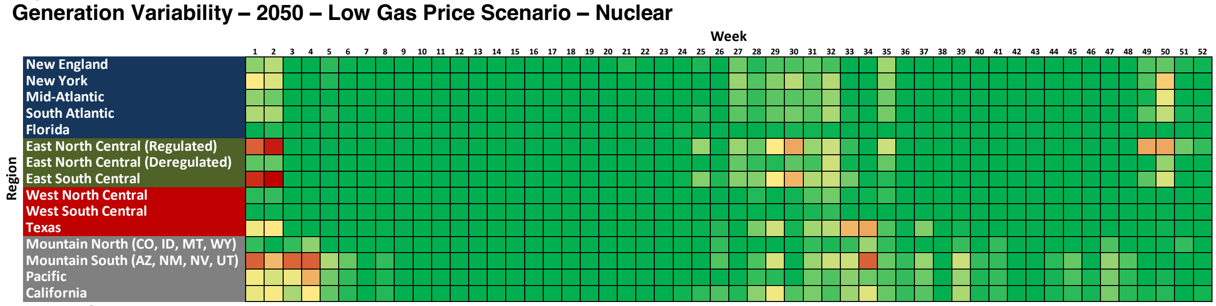


Figure C-49
Generation Variability – 2050 – Low Gas Price Scenario – Combustion Turbine

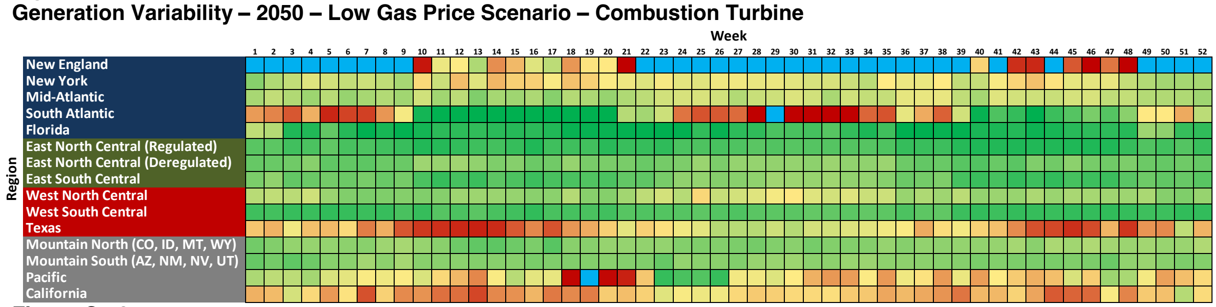


Figure C-50
Generation Variability – 2050 – Low Gas Price Scenario – Imports

Generation Variability Heat Maps – 2025 – High Gas Price Scenario (detailed UC Region=TX)

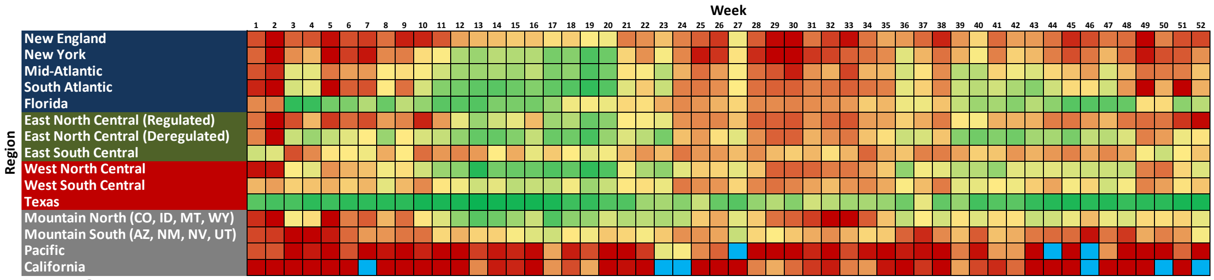


Figure C-51
Generation Variability – 2025 – High Gas Price Scenario – Natural Gas Combined Cycle

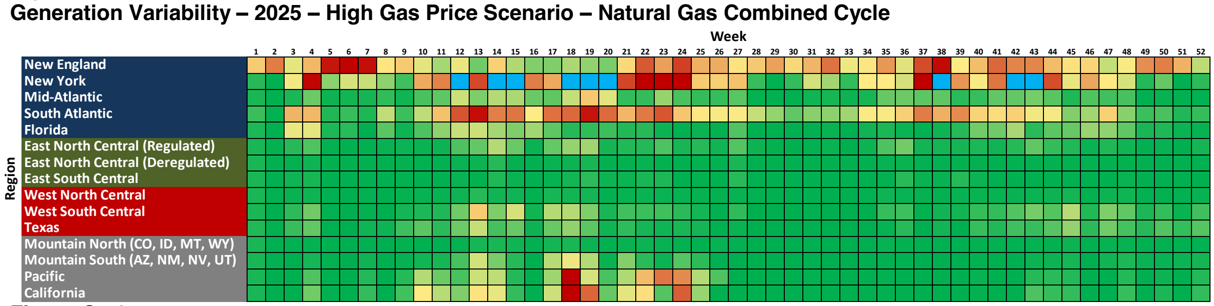


Figure C-52
Generation Variability – 2025 – High Gas Price Scenario – Coal

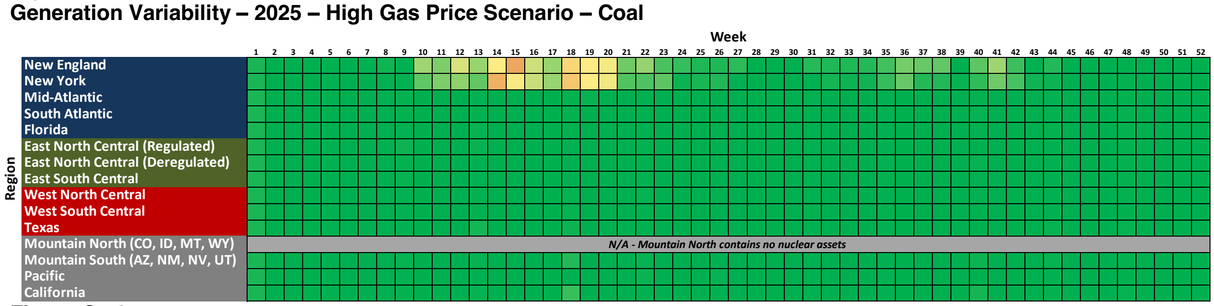


Figure C-53
Generation Variability – 2025 – High Gas Price Scenario – Nuclear

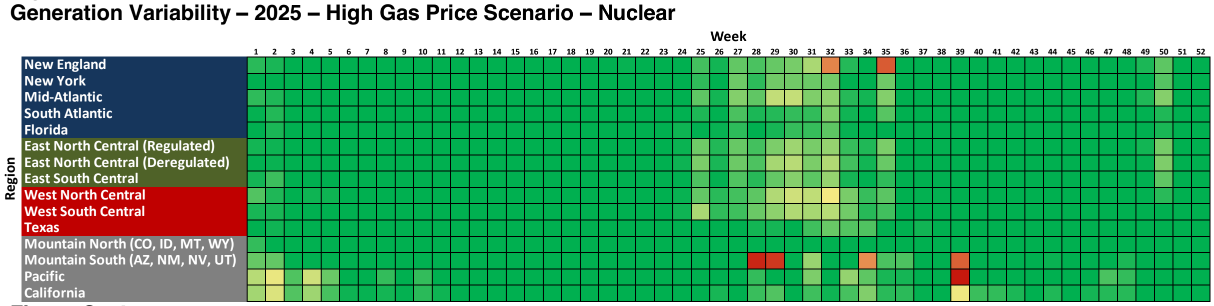


Figure C-54
Generation Variability – 2025 – High Gas Price Scenario – Combustion Turbine

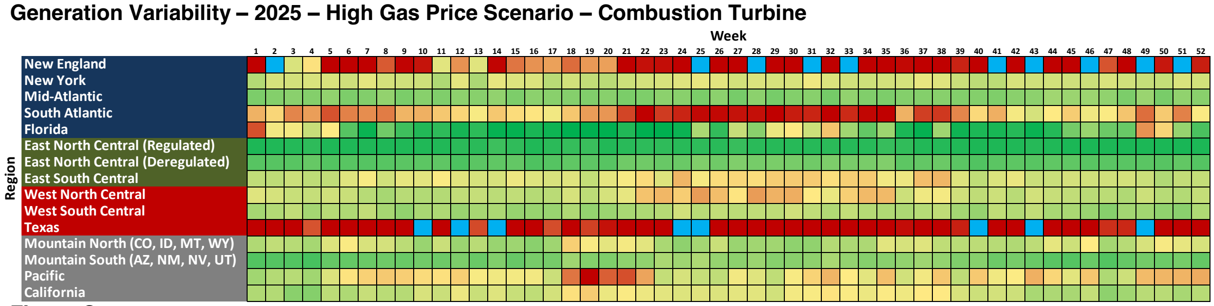


Figure C-55
Generation Variability – 2025 – High Gas Price Scenario – Imports

Generation Variability Heat Maps – 2025 – High Gas Price Scenario (detailed UC Region=NWC)

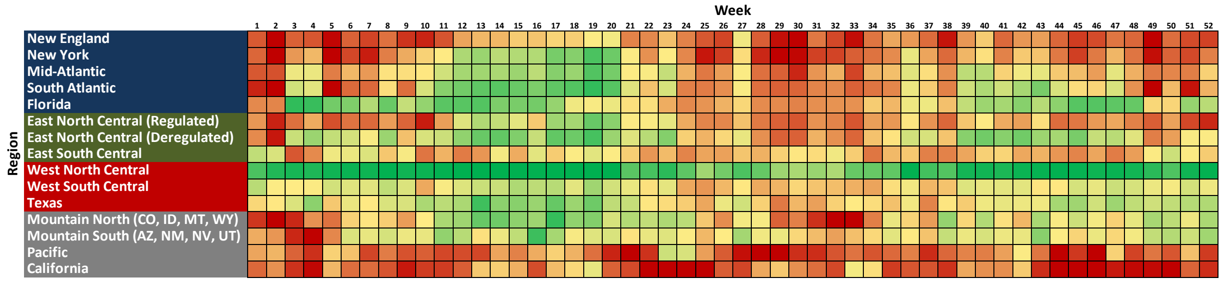


Figure C-56
Generation Variability – 2025 – High Gas Price Scenario – Natural Gas Combined Cycle

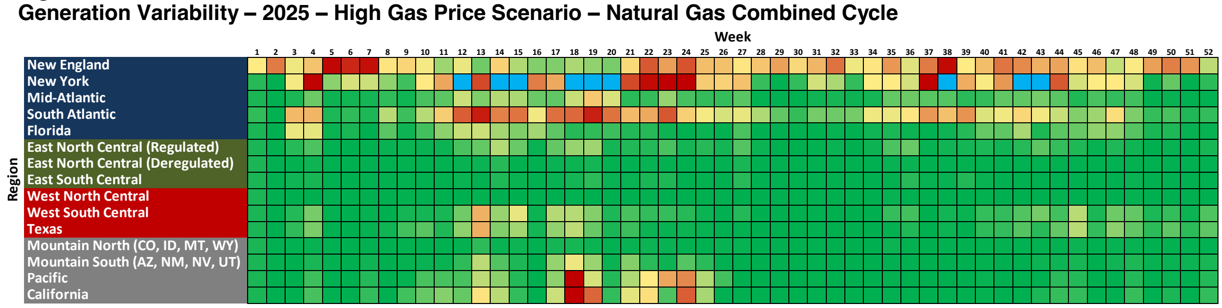


Figure C-57
Generation Variability – 2025 – High Gas Price Scenario – Coal

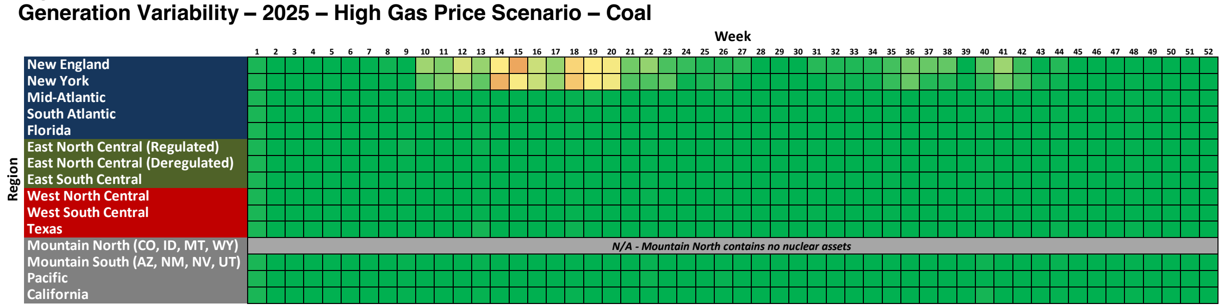


Figure C-58
Generation Variability – 2025 – High Gas Price Scenario – Nuclear

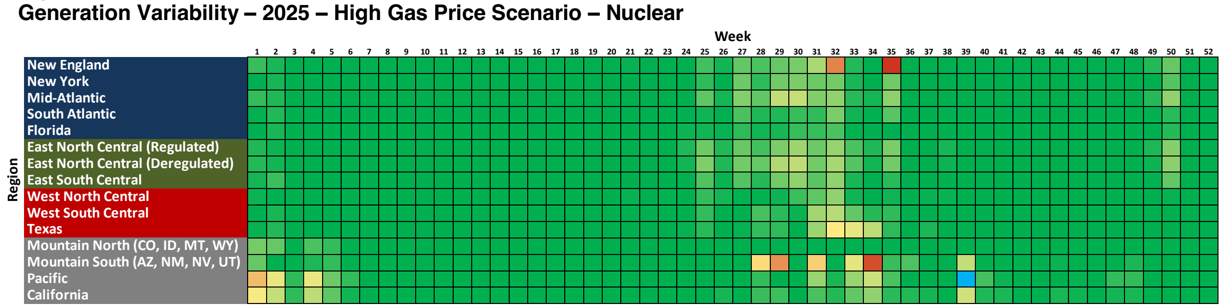


Figure C-59
Generation Variability – 2025 – High Gas Price Scenario – Combustion Turbine

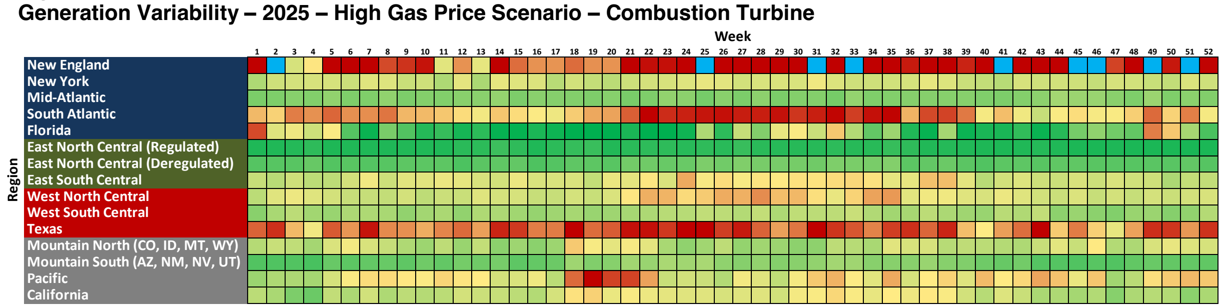


Figure C-60
Generation Variability – 2025 – High Gas Price Scenario – Imports

Generation Variability Heat Maps – 2050 – High Gas Price Scenario (detailed UC Region=TX)

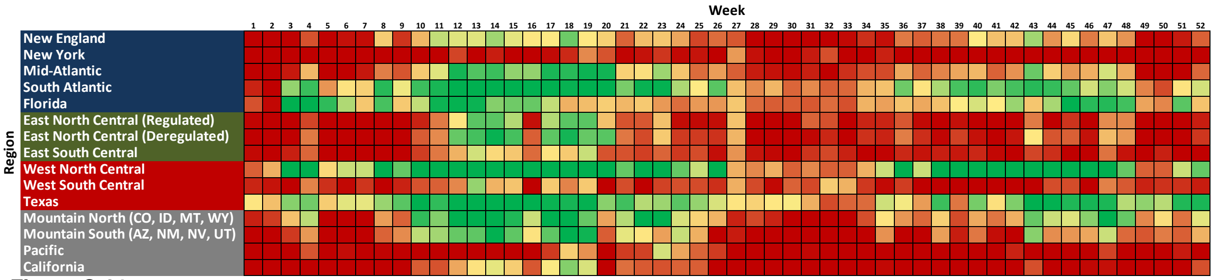


Figure C-61
Generation Variability – 2050 – High Gas Price Scenario – Natural Gas Combined Cycle

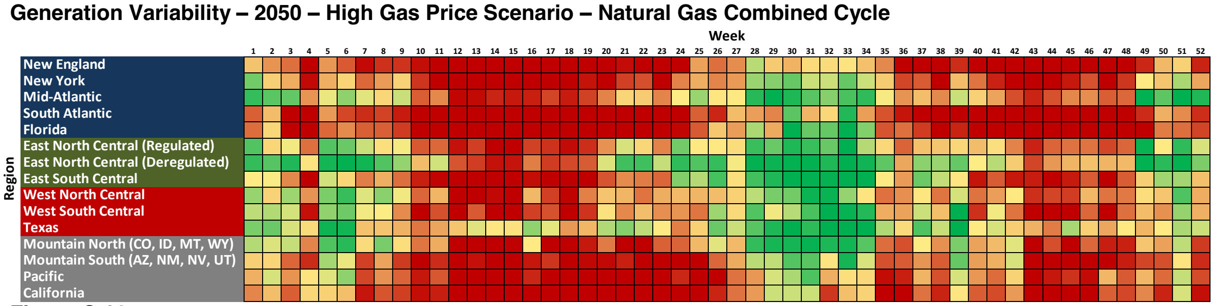


Figure C-62
Generation Variability – 2050 – High Gas Price Scenario – Coal

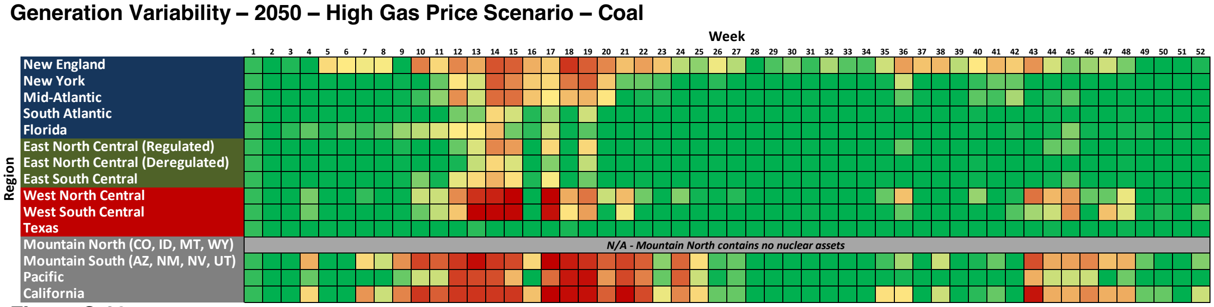


Figure C-63
Generation Variability – 2050 – High Gas Price Scenario – Nuclear

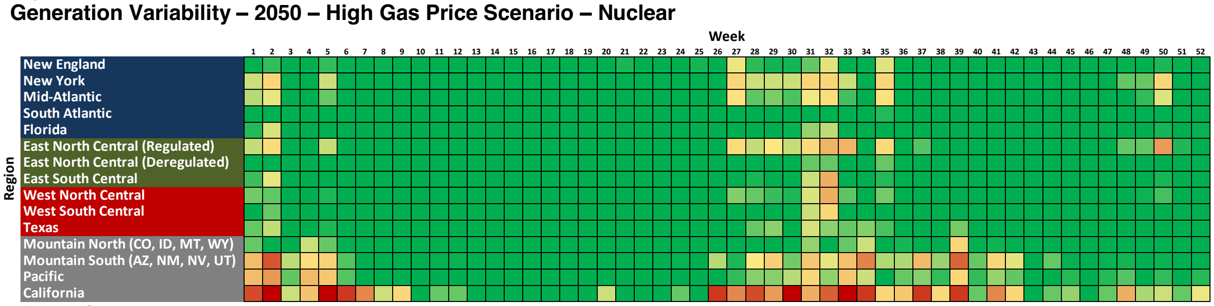


Figure C-64
Generation Variability – 2050 – High Gas Price Scenario – Combustion Turbine

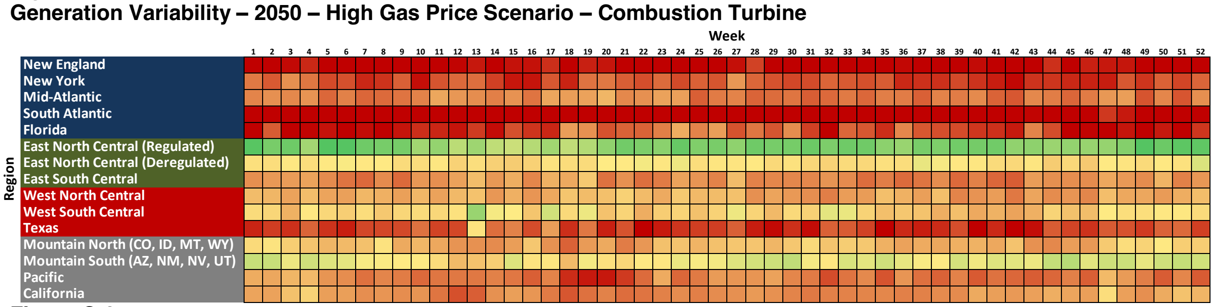


Figure C-65
Generation Variability – 2050 – High Gas Price Scenario – Imports

Generation Variability Heat Maps – 2050 – High Gas Price Scenario (detailed UC Region=NWC)

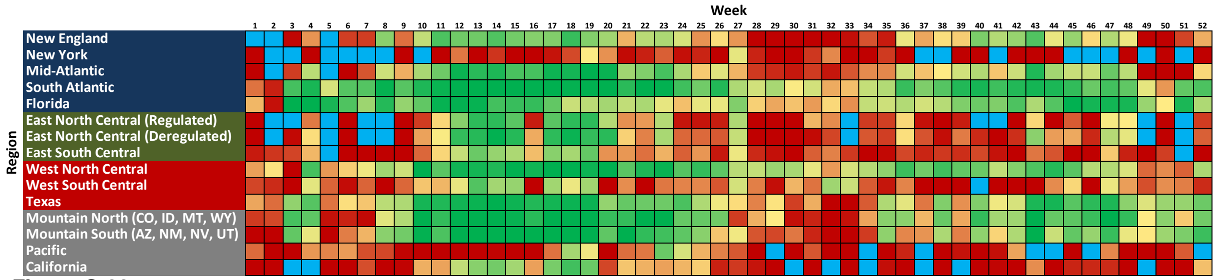


Figure C-66
Generation Variability – 2050 – High Gas Price Scenario – Natural Gas Combined Cycle

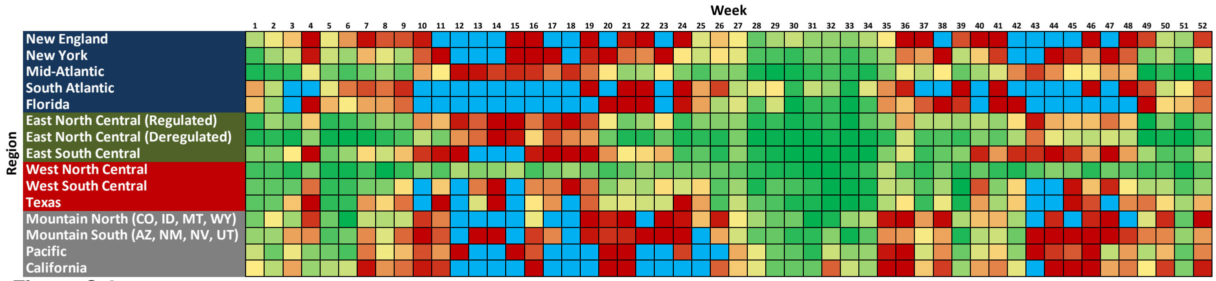


Figure C-67
Generation Variability – 2050 – High Gas Price Scenario – Coal

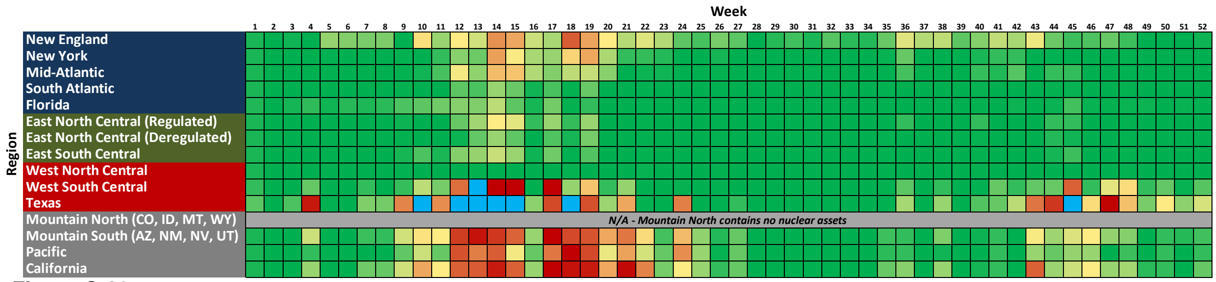


Figure C-68
Generation Variability – 2050 – High Gas Price Scenario – Nuclear

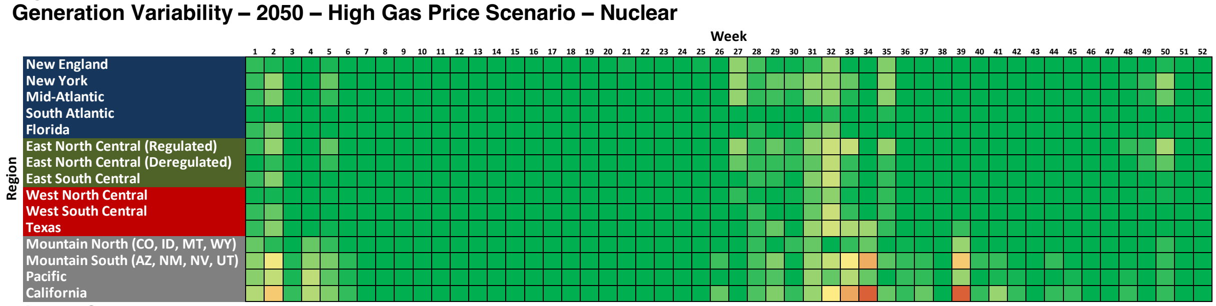


Figure C-69
Generation Variability – 2050 – High Gas Price Scenario – Combustion Turbine

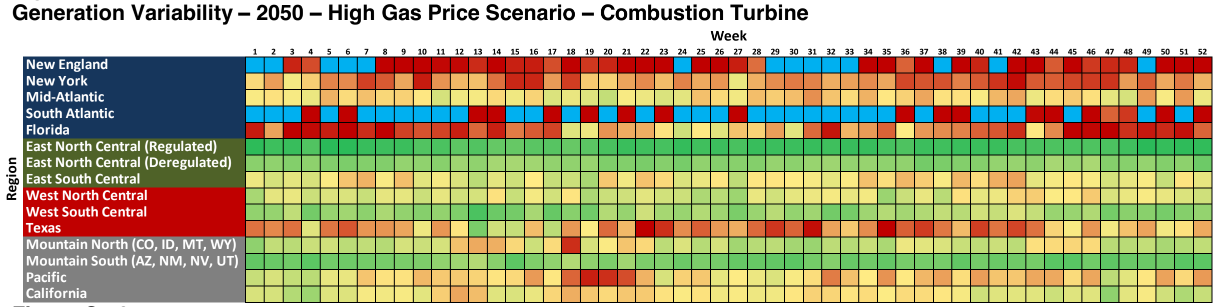


Figure C-70
Generation Variability – 2050 – High Gas Price Scenario – Imports

Generation Variability Heat Maps – 2025 – High Gas Price/No New Transmission Scenario (detailed UC Region=TX)

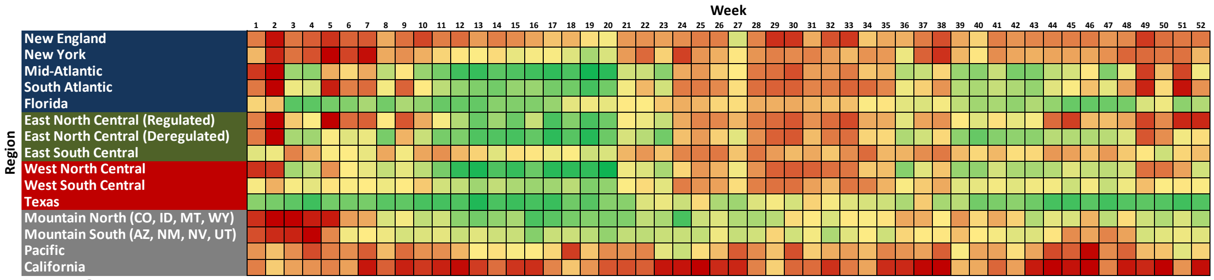


Figure C-71
Generation Variability – 2025 – High Gas Price/No New Transmission Scenario – Natural Gas Combined Cycle

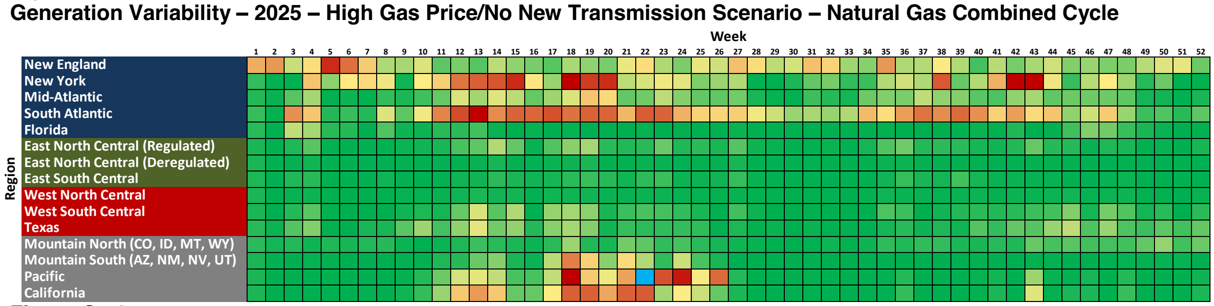


Figure C-72
Generation Variability – 2025 – High Gas Price/No New Transmission Scenario – Coal

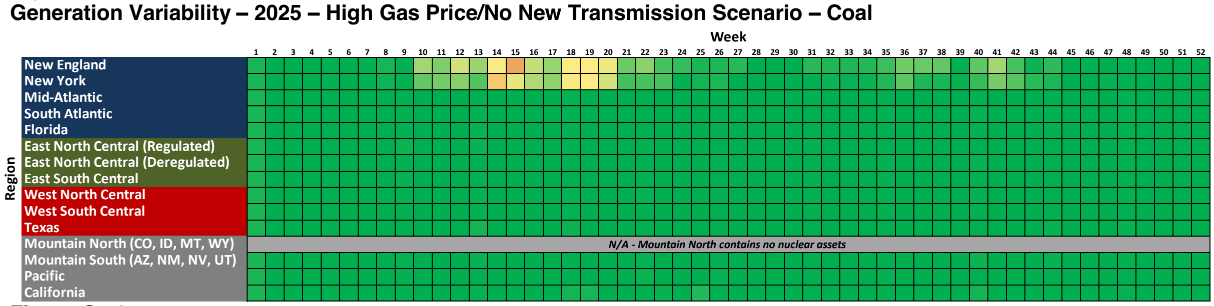


Figure C-73
Generation Variability – 2025 – High Gas Price/No New Transmission Scenario – Nuclear

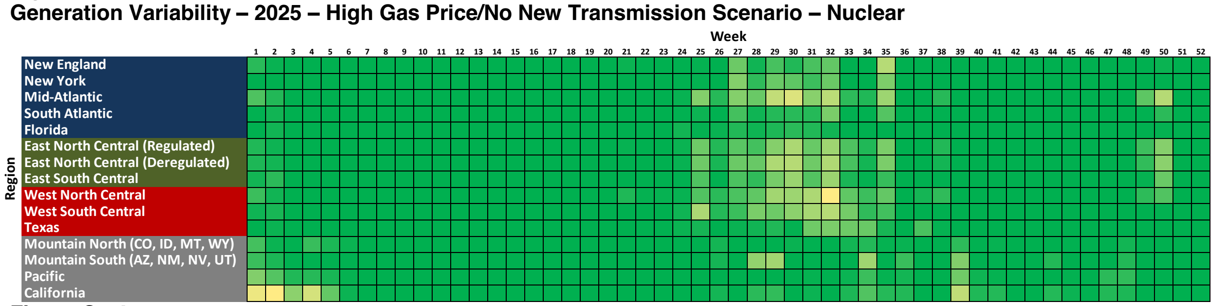


Figure C-74
Generation Variability – 2025 – High Gas Price/No New Transmission Scenario – Combustion Turbine

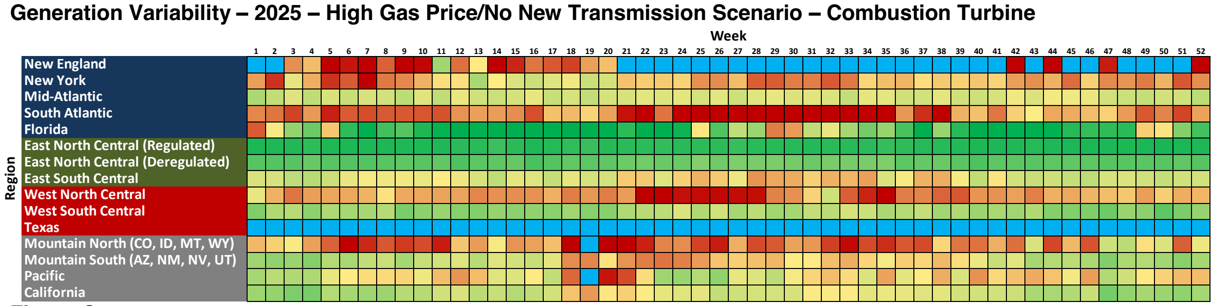


Figure C-75
Generation Variability – 2025 – High Gas Price/No New Transmission Scenario – Imports

Generation Variability Heat Maps – 2025 – High Gas Price/No New Transmission Scenario (detailed UC Region=NWC)

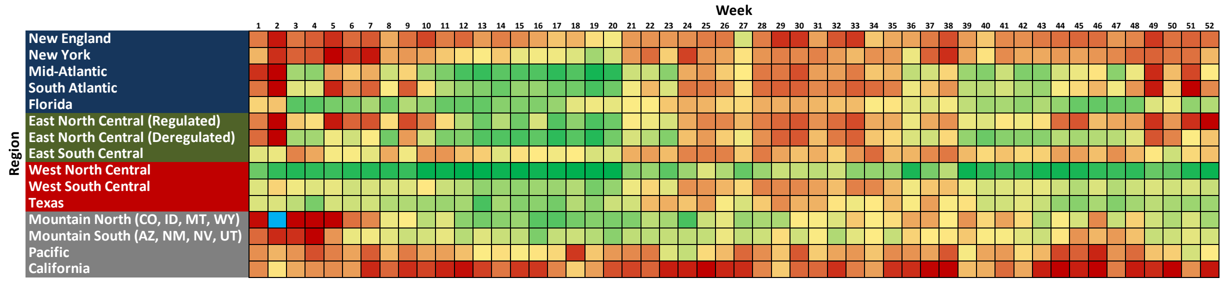


Figure C-76
Generation Variability – 2025 – High Gas Price/No New Transmission Scenario – Natural Gas Combined Cycle

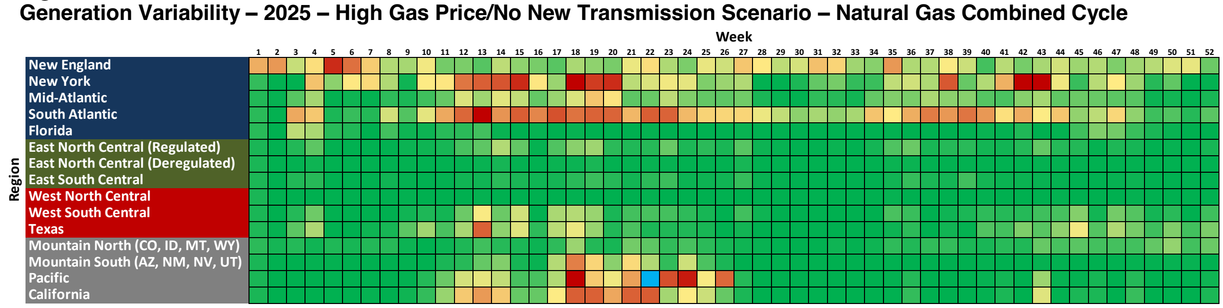


Figure C-77
Generation Variability – 2025 – High Gas Price/No New Transmission Scenario – Coal

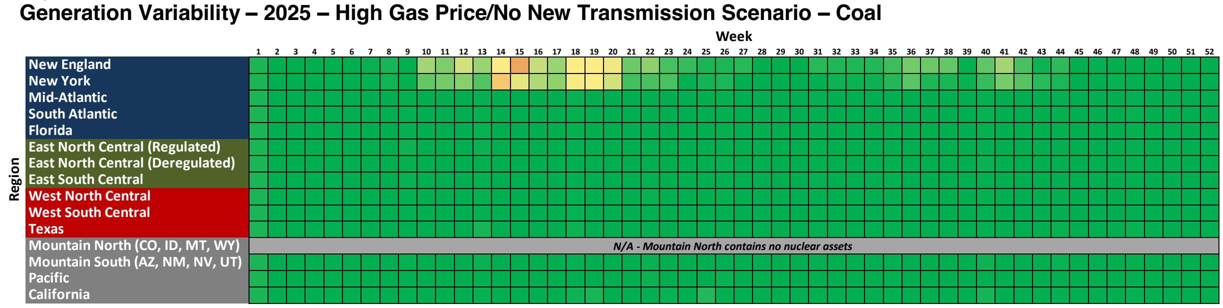


Figure C-78
Generation Variability – 2025 – High Gas Price/No New Transmission Scenario – Nuclear

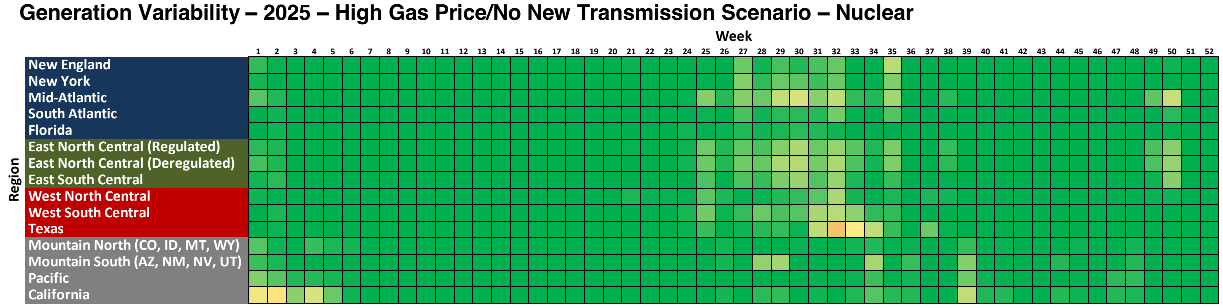


Figure C-79
Generation Variability – 2025 – High Gas Price/No New Transmission Scenario – Combustion Turbine

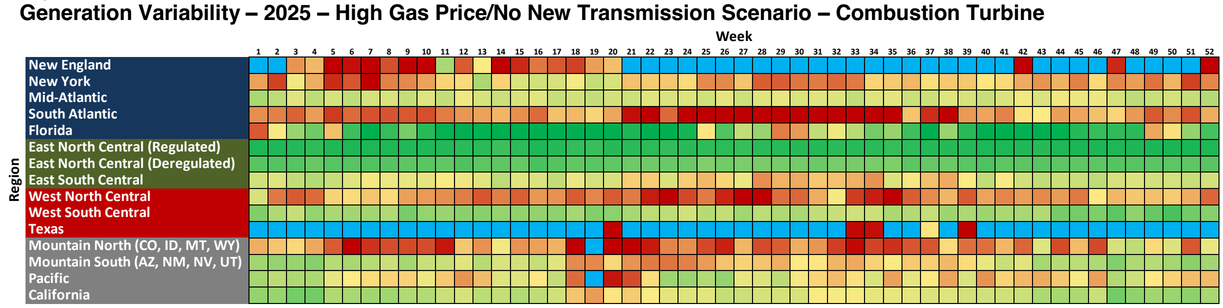


Figure C-80
Generation Variability – 2025 – High Gas Price/No New Transmission Scenario – Imports

Generation Variability Heat Maps – 2050 – High Gas Price/No New Transmission Scenario (detailed UC Region=TX)

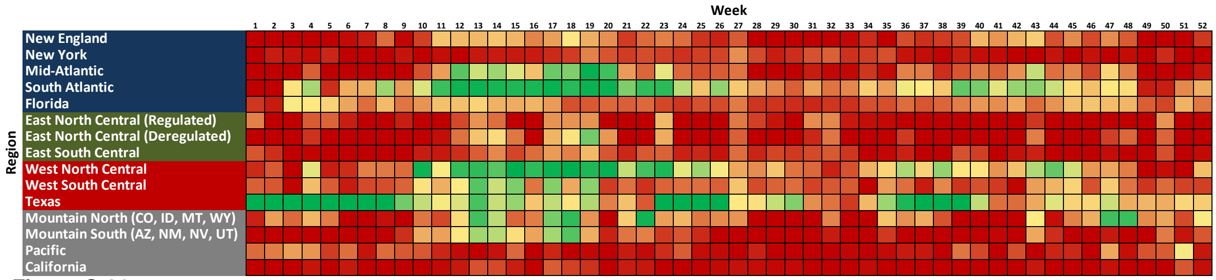


Figure C-81
Generation Variability – 2050 – High Gas Price/No New Transmission Scenario – Natural Gas Combined Cycle

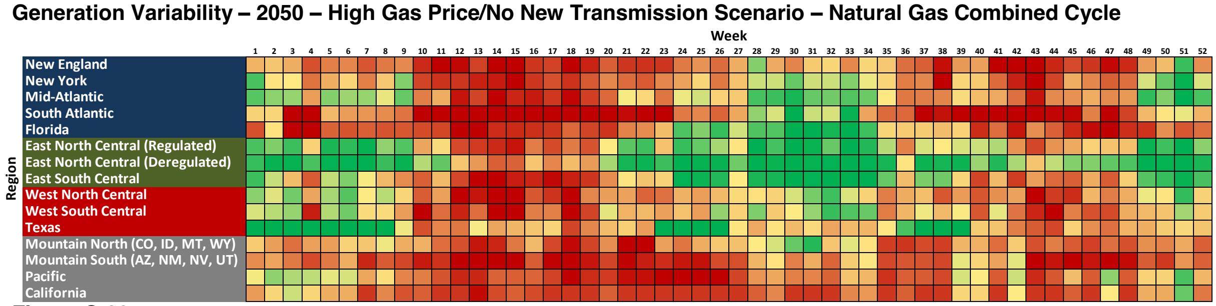


Figure C-82
Generation Variability – 2050 – High Gas Price/No New Transmission Scenario – Coal

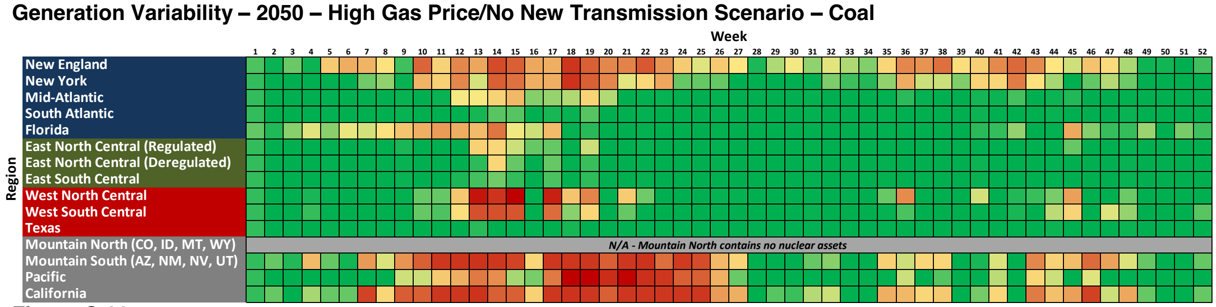


Figure C-83
Generation Variability – 2050 – High Gas Price/No New Transmission Scenario – Nuclear

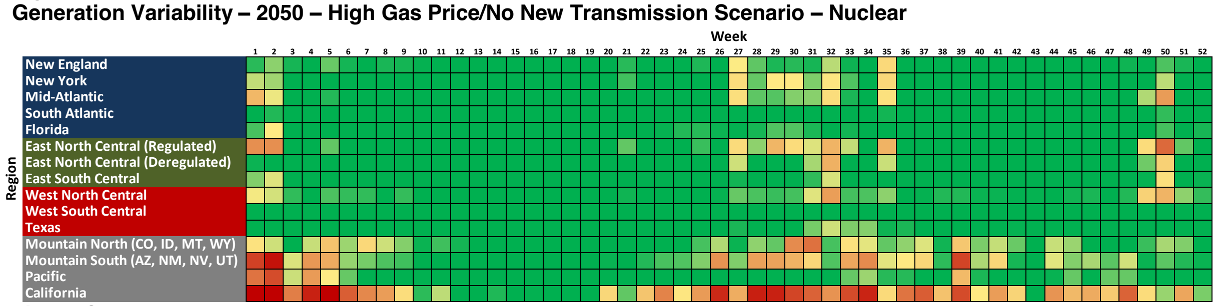


Figure C-84
Generation Variability – 2050 – High Gas Price/No New Transmission Scenario – Combustion Turbine

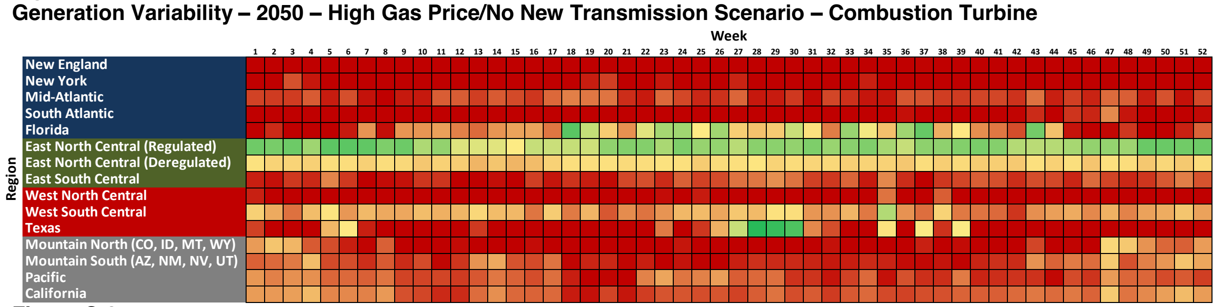


Figure C-85
Generation Variability – 2050 – High Gas Price/No New Transmission Scenario – Imports

Generation Variability Heat Maps – 2050 – High Gas Price/No New Transmission Scenario (detailed UC Region=NWC)

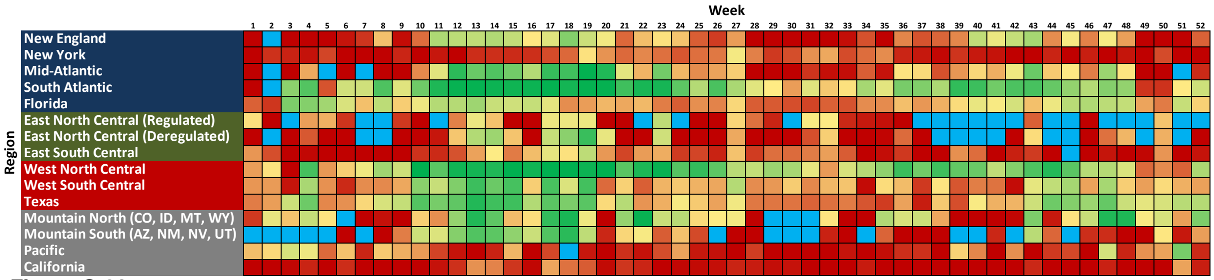


Figure C-86
Generation Variability – 2050 – High Gas Price/No New Transmission Scenario – Natural Gas Combined Cycle

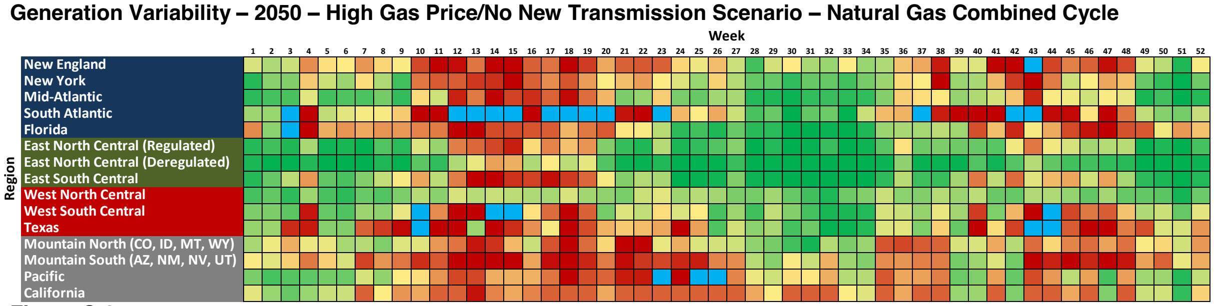


Figure C-87
Generation Variability – 2050 – High Gas Price/No New Transmission Scenario – Coal

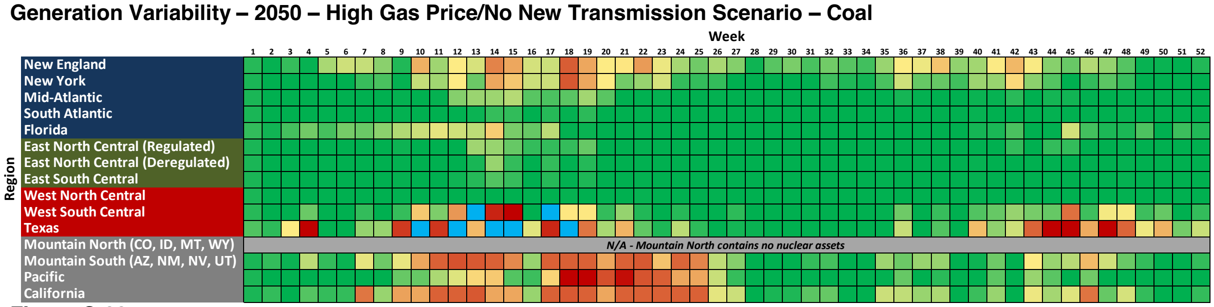


Figure C-88
Generation Variability – 2050 – High Gas Price/No New Transmission Scenario – Nuclear

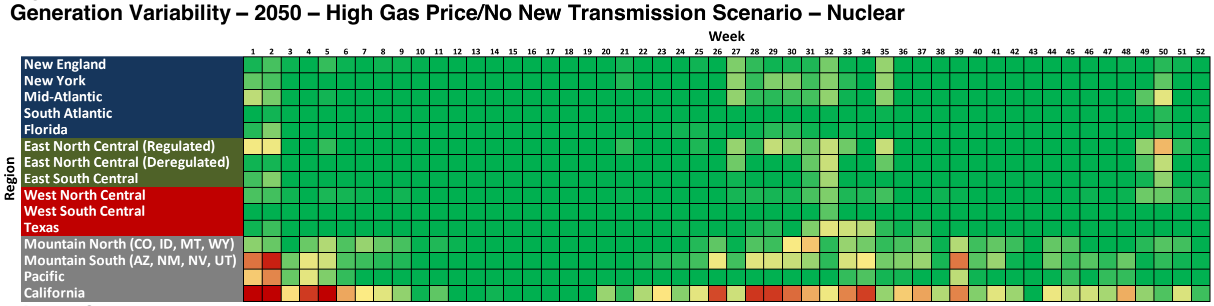


Figure C-89
Generation Variability – 2050 – High Gas Price/No New Transmission Scenario – Combustion Turbine

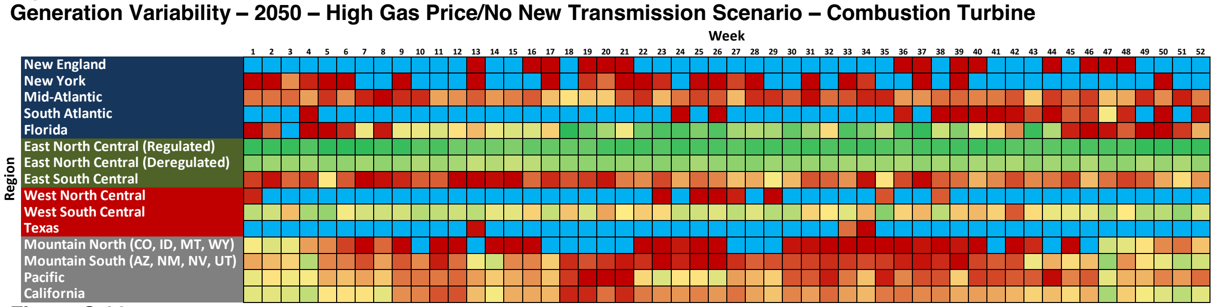


Figure C-90
Generation Variability – 2050 – High Gas Price/No New Transmission Scenario – Imports

Capacity Factor Heat Maps – 2015 – Reference Scenario (detailed UC Region=TX)

Week

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.9	0.9	0.8	0.8	0.9	0.9	0.9	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.5	0.6	0.8	0.8	0.7	0.7	0.8	0.8
New York	0.8	0.8	0.7	0.6	0.7	0.7	0.7	0.6	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.7	0.7	0.6	0.6	0.8	0.7
Mid-Atlantic	0.7	0.7	0.5	0.5	0.6	0.6	0.6	0.5	0.6	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.4	0.5	0.5	0.5	0.5	0.7	0.6
South Atlantic	1.0	1.0	0.9	0.9	1.0	1.0	1.0	0.9	1.0	0.9	0.8	0.7	0.7	0.6	0.6	0.6	0.6	0.7	0.6	0.7	0.8	0.8	0.8	0.9	0.9	0.9
Florida	0.5	0.7	0.2	0.2	0.2	0.3	0.4	0.2	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.7
East North Central (Regulated)	0.9	1.0	0.8	0.8	0.9	0.9	0.9	0.8	0.9	0.9	0.8	0.8	0.8	0.7	0.7	0.8	0.7	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.9	0.8
East North Central (Deregulated)	0.7	0.7	0.5	0.5	0.6	0.6	0.6	0.5	0.6	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.5	0.4	0.4	0.6	0.6	0.5	0.6	0.7	0.7
East South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0
West North Central	0.5	0.4	0.3	0.3	0.4	0.4	0.4	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.4	0.4	0.3	0.4	0.6	0.5
West South Central	0.7	0.8	0.6	0.5	0.7	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.7	0.7	0.7	0.7	0.8	0.7
Texas	0.7	0.7	0.4	0.3	0.6	0.6	0.6	0.5	0.4	0.3	0.3	0.3	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.6	0.6	0.7	0.7	0.7
Mountain North (CO, ID, MT, WY)	0.6	0.6	0.5	0.5	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.2	0.3
Mountain South (AZ, NM, NV, UT)	0.6	0.7	0.6	0.6	0.5	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.5	0.4	0.5	0.5
Pacific	1.0	1.0	0.9	1.0	0.9	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7	0.6	0.6	0.7	0.6	0.5	0.4	0.4	0.5	0.3	0.1	0.1	0.1	0.2
California	0.9	0.9	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.7	0.7

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.7	0.7	0.7	0.8	0.7	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.9	0.9	0.9	0.8
New York	0.8	0.9	0.9	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.6	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.8	0.7	0.7
Mid-Atlantic	0.6	0.7	0.8	0.8	0.7	0.7	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.4	0.5	0.4	0.4	0.4	0.5	0.4	0.4	0.5	0.6	0.7	0.7	0.5
South Atlantic	0.8	0.9	0.9	1.0	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.8	0.9	0.9	0.8	0.9	1.0	1.0	1.0	1.0
Florida	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.5	0.6	0.6	0.5	0.4	0.4	0.3	0.5	0.4	0.2	0.2	0.2	0.3	0.4	0.5	0.3	0.4
East North Central (Regulated)	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9
East North Central (Deregulated)	0.7	0.7	0.8	0.8	0.7	0.7	0.7	0.6	0.7	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.7	0.8	0.7	0.6
East South Central	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0
West North Central	0.4	0.5	0.7	0.7	0.6	0.6	0.6	0.5	0.5	0.3	0.4	0.5	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.4	0.3	0.4	0.4	0.5	0.4	0.3
West South Central	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.6	0.7	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Texas	0.6	0.7	0.8	0.7	0.8	0.8	0.8	0.8	0.7	0.6	0.7	0.6	0.5	0.4	0.5	0.5	0.5	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
Mountain North (CO, ID, MT, WY)	0.2	0.3	0.3	0.3	0.4	0.3	0.4	0.3	0.3	0.3	0.4	0.3	0.4	0.3	0.3	0.3	0.2	0.2	0.2	0.3	0.3	0.3	0.2	0.2	0.2	0.2
Mountain South (AZ, NM, NV, UT)	0.5	0.6	0.7	0.6	0.6	0.5	0.6	0.6	0.5	0.5	0.5	0.5	0.6	0.5	0.5	0.5	0.4	0.4	0.4	0.4	0.5	0.4	0.3	0.3	0.3	0.3
Pacific	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.9	0.9	0.9	0.9	0.7	0.7	0.7	0.7
California	0.7	0.8	0.8	0.8	0.8	0.7	0.8	0.8	0.7	0.7	0.7	0.7	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.6

Figure C-91
Capacity Factor – 2015 – Reference Scenario – Natural Gas Combined Cycle

Week

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.1	0.0	0.0	0.3	0.3
New York	0.4	0.5	0.2	0.2	0.3	0.3	0.2	0.1	0.3	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.3	0.1	0.3	0.5	0.4
Mid-Atlantic	0.8	0.8	0.7	0.7	0.8	0.7	0.7	0.7	0.7	0.6	0.6	0.5	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.7	0.8	0.7	0.8	0.8	0.8
South Atlantic	0.3	0.3	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.1	0.0	0.2	0.4	0.2
Florida	0.6	0.7	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.7	0.8
East North Central (Regulated)	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	0.9	0.9	0.9	1.0	1.0	0.9	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	0.8	0.9	0.2	0.3	0.5	0.5	0.5	0.3	0.5	0.1	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.3	0.3	0.5	0.6	0.5
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Texas	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain North (CO, ID, MT, WY)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.6	0.4	0.4	0.4	0.5
California	0.8	0.9	0.8	0.8	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.5	0.6	0.7

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.3	0.4	0.5	0.5	0.3	0.4	0.3	0.1	0.3	0.2	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0
New York	0.5	0.6	0.7	0.6	0.6	0.6	0.5	0.4	0.5	0.3	0.3	0.3	0.2	0.0	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.3	0.4	0.4	0.1
Mid-Atlantic	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.6	0.7	0.6	0.6	0.6	0.6	0.7	0.6	0.7	0.8	0.8	0.8	0.7
South Atlantic	0.3	0.3	0.5	0.5	0.3	0.4	0.4	0.2	0.3	0.1	0.1	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.4	0.1	0.1
Florida	0.7	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.5	0.5	0.5	0.6	0.5	0.5	0.5	0.5	0.5	0.6	0.6	0.5	0.6
East North Central (Regulated)	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	0.5	0.6	0.6	0.7	0.6	0.6	0.6	0.5	0.5	0.3	0.4	0.4	0.2	0.0	0.1	0.0	0.1	0.1	0.2	0.2	0.1	0.3	0.7	0.8	0.7	0.6
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Texas	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain North (CO, ID, MT, WY)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
California	0.6	0.7	0.7	0.7	0.7	0.6	0.7	0.7	0.6	0.7	0.7	0.7	0.7	0.6	0.6	0.5	0.5	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5

Figure C-92
Capacity Factor – 2015 – Reference Scenario – Coal

Week

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
New York	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mid-Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
South Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Florida	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Regulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Texas	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain North (CO, ID, MT, WY)	*N/A - Mountain North contains no nuclear assets*																									
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
California	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
New York	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mid-Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
South Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Florida	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Regulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Texas	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain North (CO, ID, MT, WY)																										
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
California	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Figure C-93
Capacity Factor – 2015 – Reference Scenario – Nuclear

Week

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
New York	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Mid-Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
South Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Florida	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
East North Central (Regulated)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
East North Central (Deregulated)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1
East South Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
West North Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
West South Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Texas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.1
Mountain North (CO, ID, MT, WY)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain South (AZ, NM, NV, UT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pacific	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
California	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.3	0.1	0.1	0.1	0.1	0.2	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New York	0.2	0.2	0.2	0.2	0.1	0.2	0.1	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid-Atlantic	0.1	0.1	0.2	0.2	0.1	0.2	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
South Atlantic	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Florida	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East North Central (Regulated)	0.1	0.1	0.2	0.2	0.1	0.2	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
East North Central (Deregulated)	0.1	0.1	0.2	0.2	0.1	0.2	0.1	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
East South Central	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West North Central	0.0	0.1	0.1	0.1	0.1	0.2	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West South Central	0.0	0.1	0.2	0.1	0.2	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Texas	0.1	0.2	0.2	0.1	0.3	0.3	0.3	0.2	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain North (CO, ID, MT, WY)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain South (AZ, NM, NV, UT)	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pacific	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
California	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Figure C-94
Capacity Factor – 2015 – Reference Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2015 – Reference Scenario (detailed UC Region=NWC)

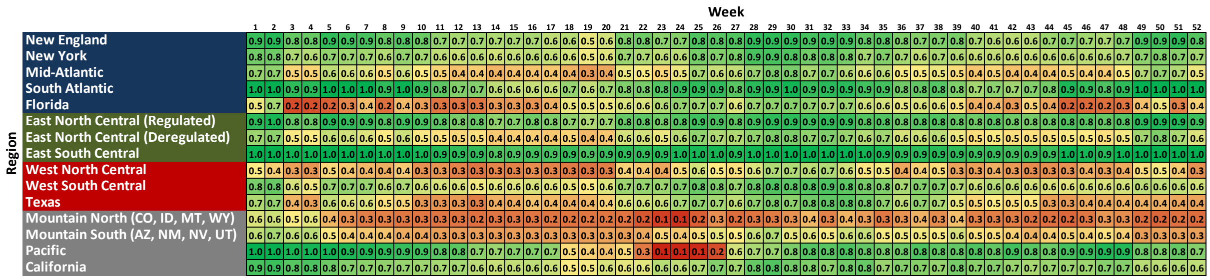


Figure C-95
Capacity Factor – 2015 – Reference Scenario – Natural Gas Combined Cycle

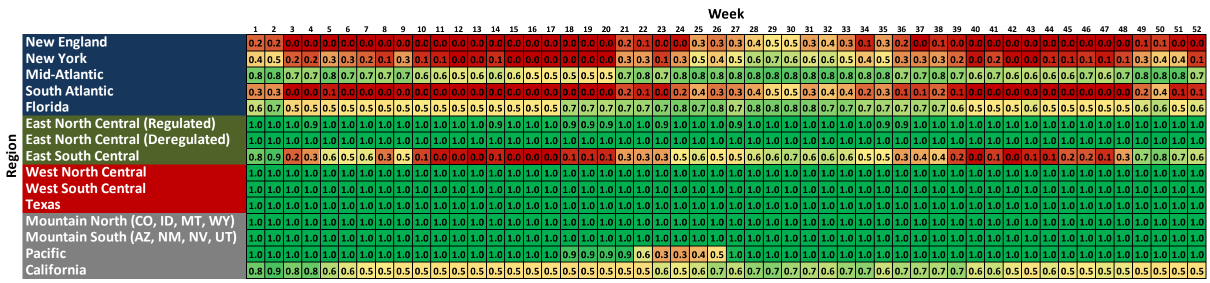


Figure C-96
Capacity Factor – 2015 – Reference Scenario – Coal

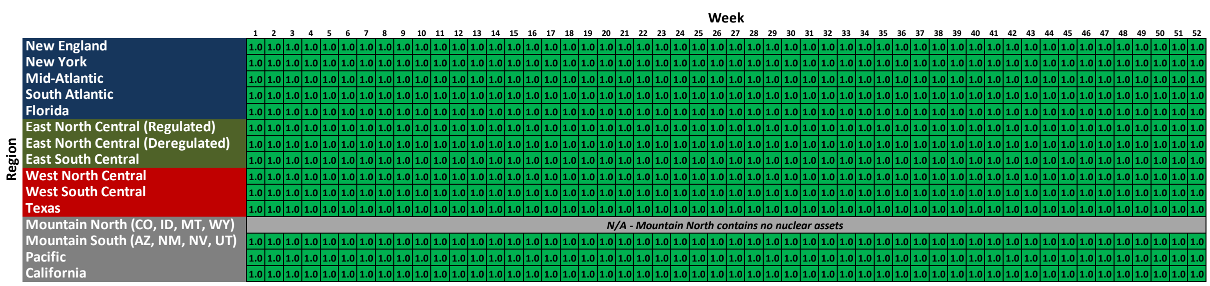


Figure C-97
Capacity Factor – 2015 – Reference Scenario – Nuclear

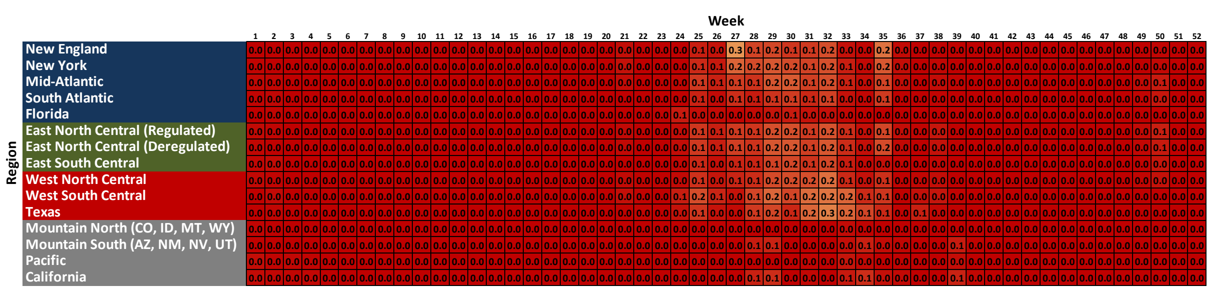


Figure C-98
Capacity Factor – 2015 – Reference Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2025 – Reference Scenario (detailed UC Region=TX)

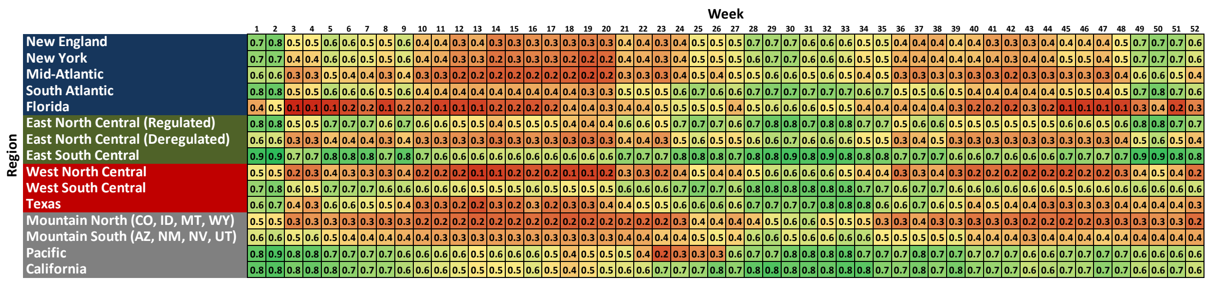


Figure C-99
Capacity Factor – 2025 – Reference Scenario – Natural Gas Combined Cycle

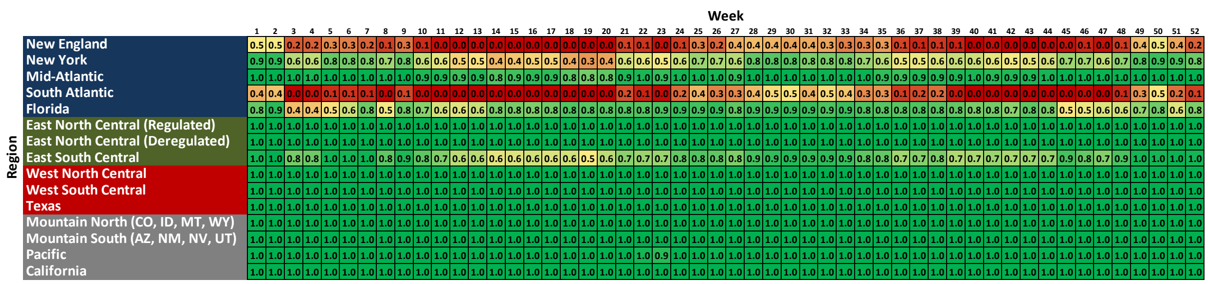


Figure C-100
Capacity Factor – 2025 – Reference Scenario – Coal

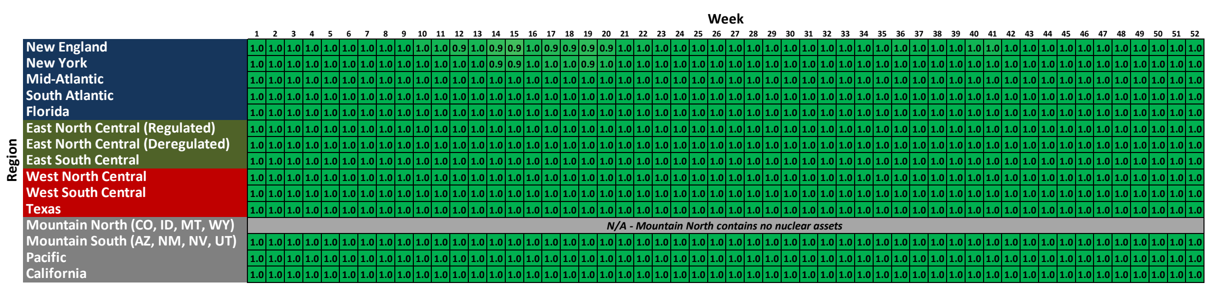


Figure C-101
Capacity Factor – 2025 – Reference Scenario – Nuclear

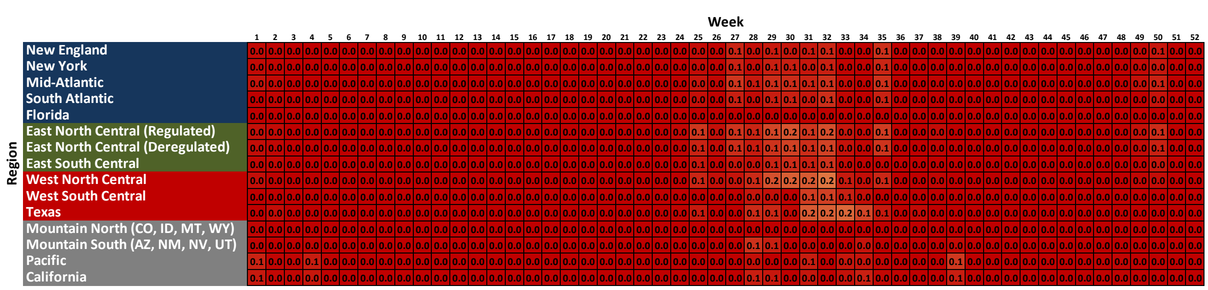


Figure C-102
Capacity Factor – 2025 – Reference Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2025 – Reference Scenario (detailed UC Region=NWC)

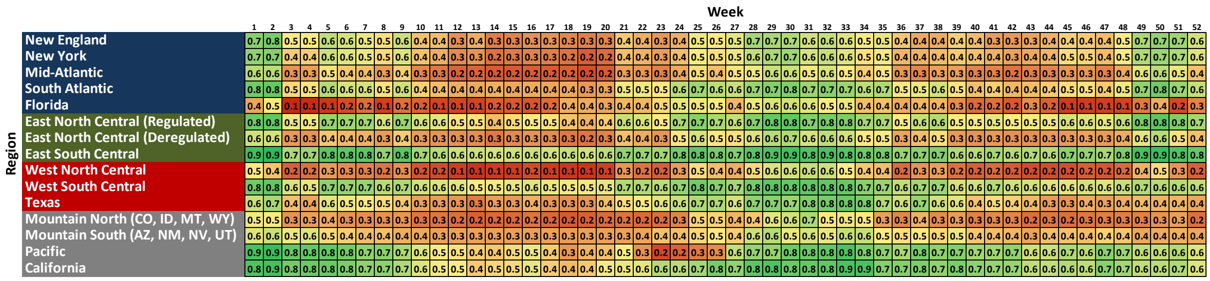


Figure C-103
Capacity Factor – 2025 – Reference Scenario – Natural Gas Combined Cycle

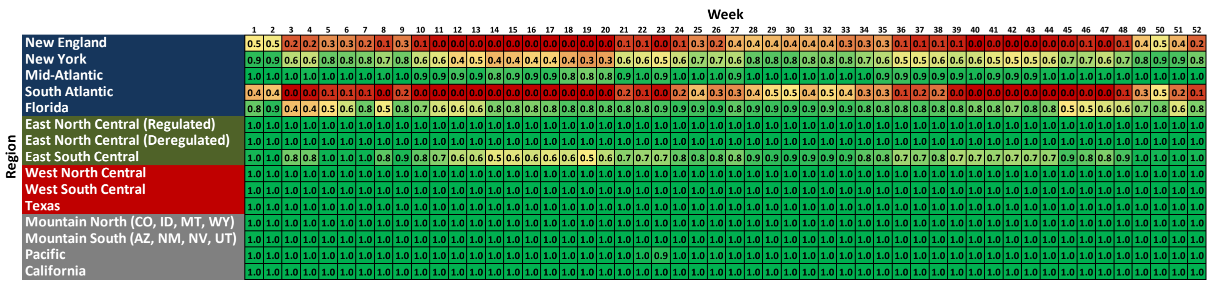


Figure C-104
Capacity Factor – 2025 – Reference Scenario – Coal

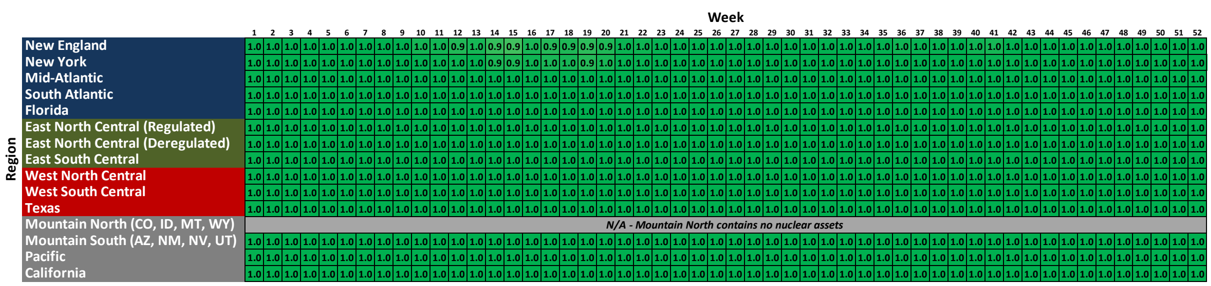


Figure C-105
Capacity Factor – 2025 – Reference Scenario – Nuclear

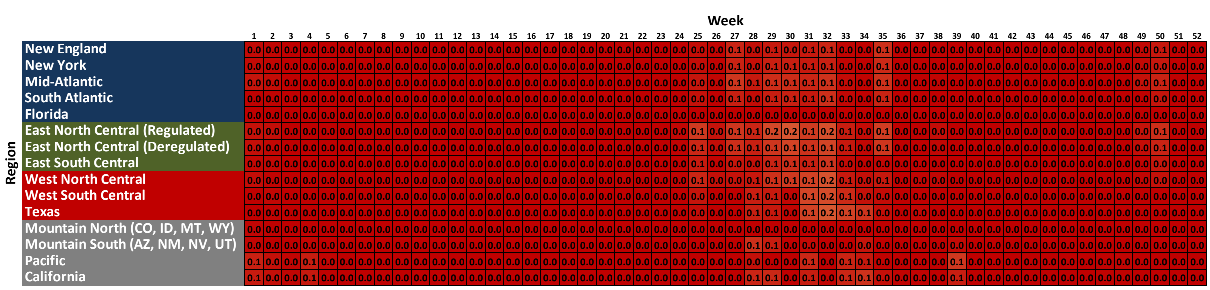


Figure C-106
Capacity Factor – 2025 – Reference Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2050 – Reference Scenario (detailed UC Region=TX)

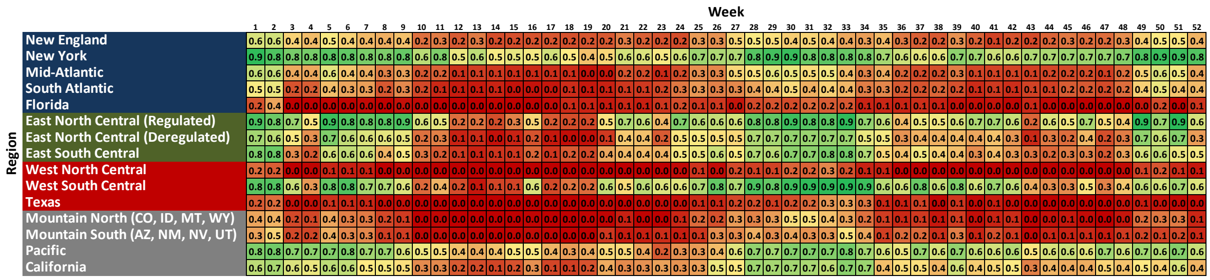


Figure C-107
Capacity Factor – 2050 – Reference Scenario – Natural Gas Combined Cycle

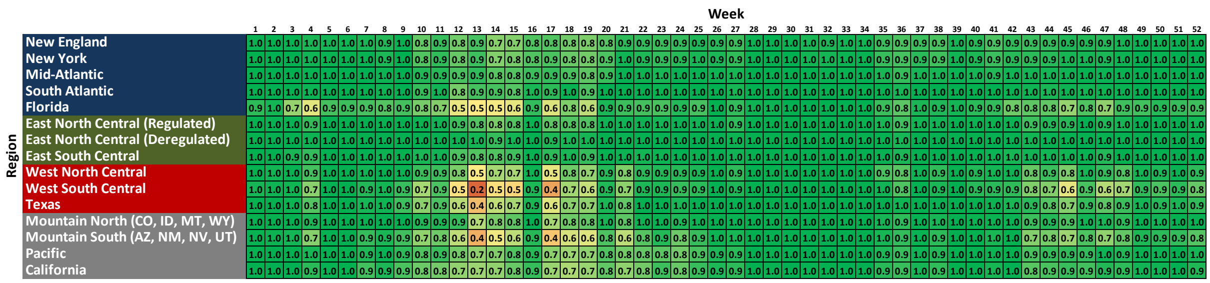


Figure C-108
Capacity Factor – 2050 – Reference Scenario – Coal

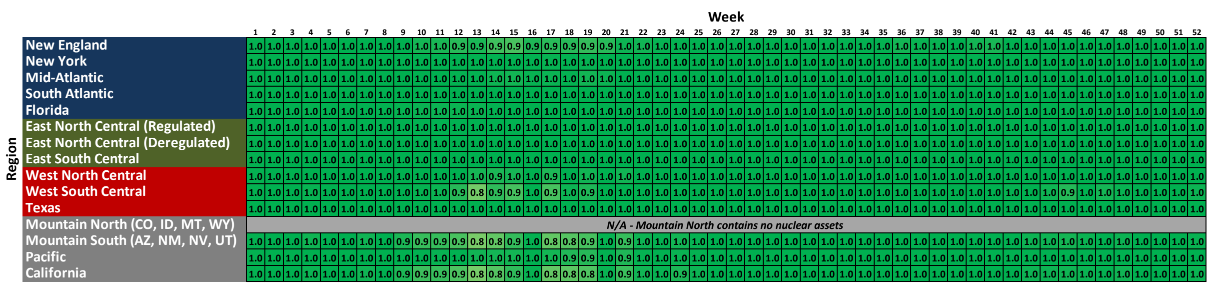


Figure C-109
Capacity Factor – 2050 – Reference Scenario – Nuclear

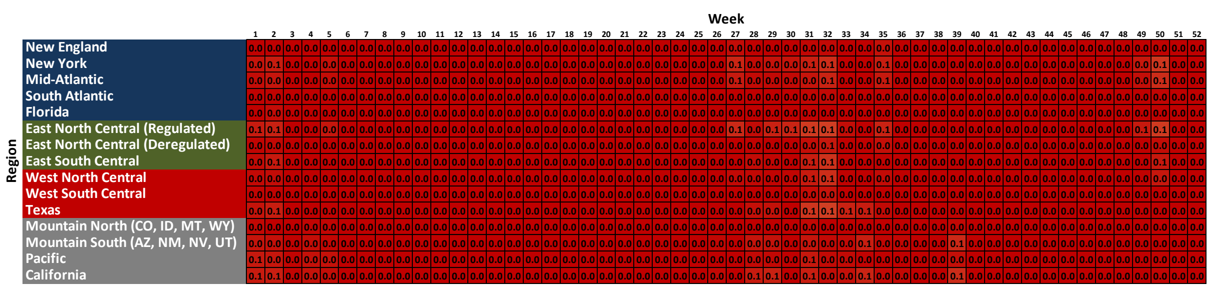


Figure C-110
Capacity Factor – 2050 – Reference Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2050 – Reference Scenario (detailed UC Region=NWC)

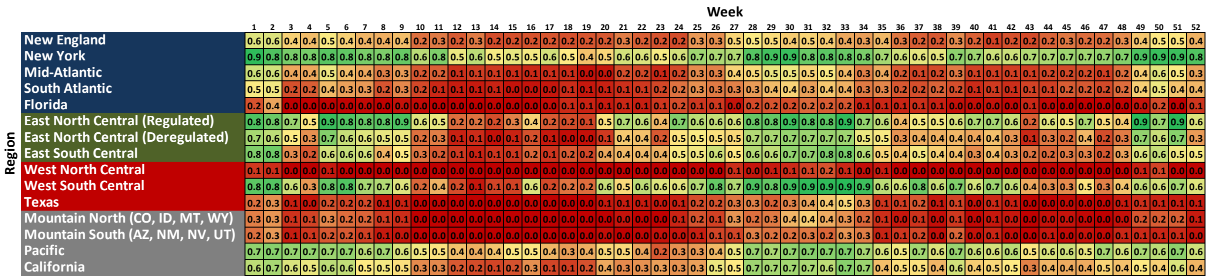


Figure C-111
Capacity Factor – 2050 – Reference Scenario – Natural Gas Combined Cycle

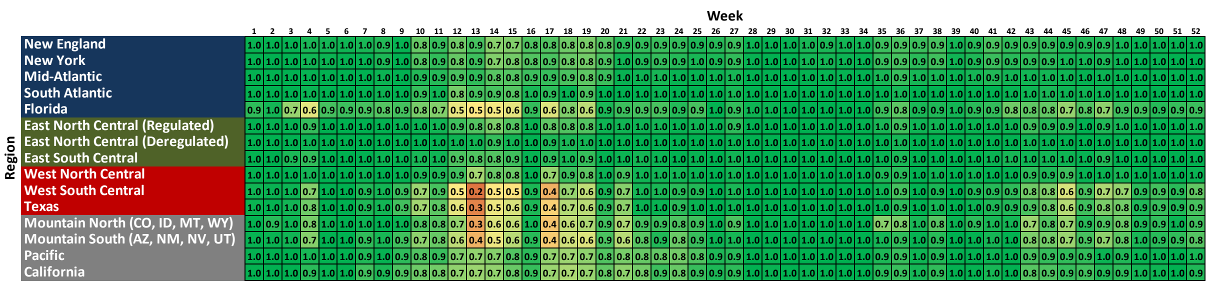


Figure C-112
Capacity Factor – 2050 – Reference Scenario – Coal

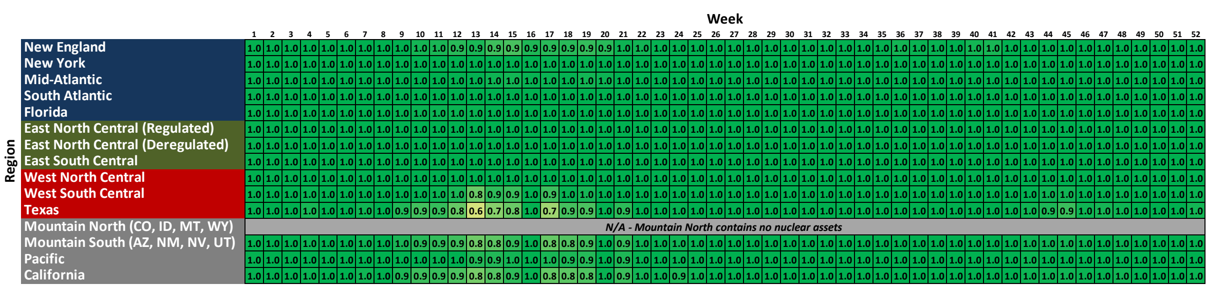


Figure C-113
Capacity Factor – 2050 – Reference Scenario – Nuclear

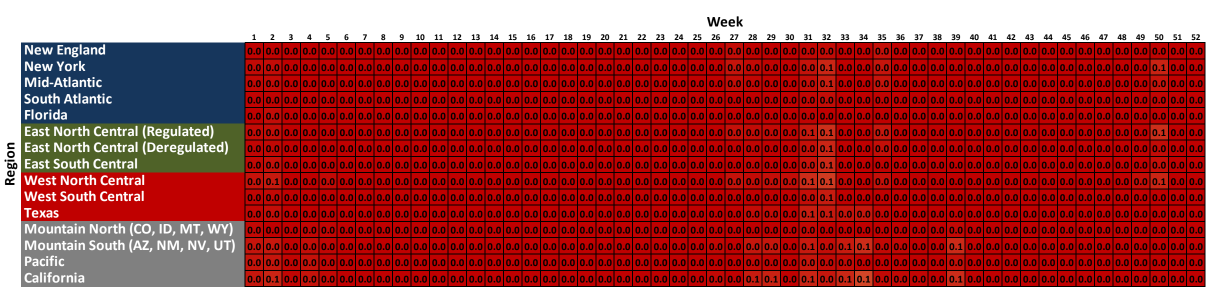


Figure C-114
Capacity Factor – 2050 – Reference Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2025 – Low Gas Price Scenario (detailed UC Region=TX)

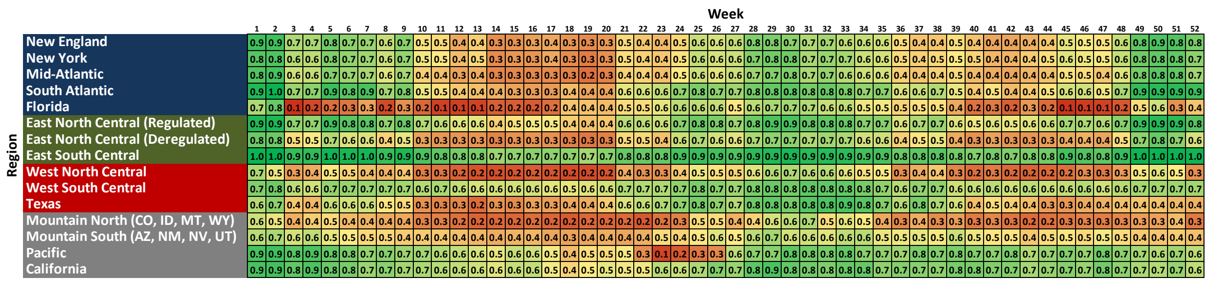


Figure C-115
Capacity Factor – 2025 – Low Gas Price Scenario – Natural Gas Combined Cycle

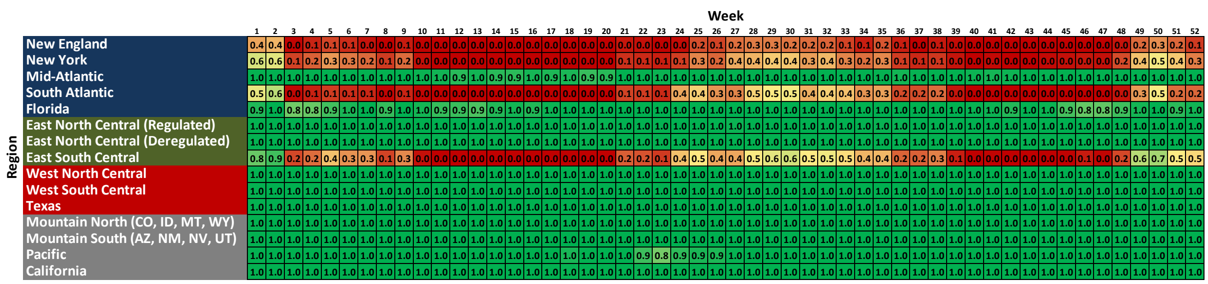


Figure C-116
Capacity Factor – 2025 – Low Gas Price Scenario – Coal

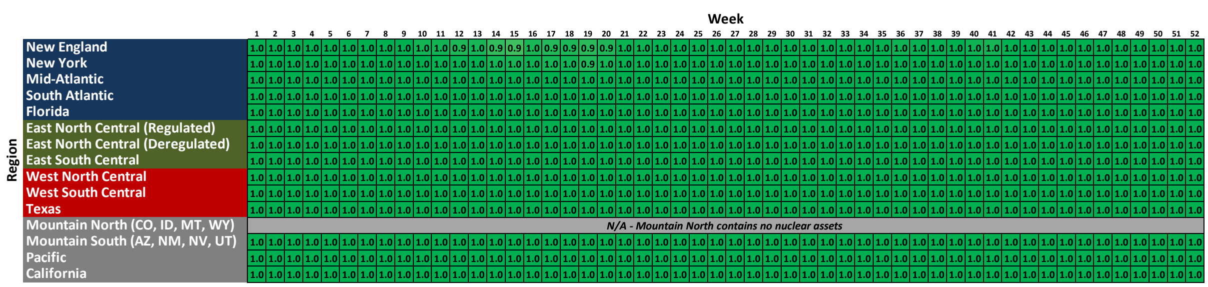


Figure C-117
Capacity Factor – 2025 – Low Gas Price Scenario – Nuclear

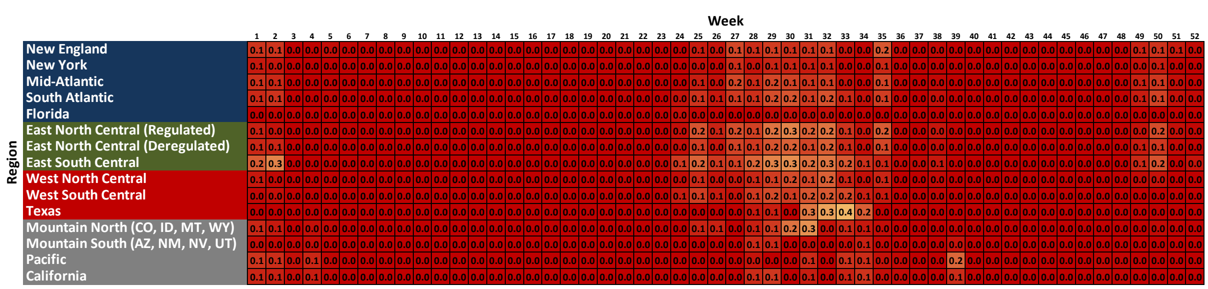


Figure C-118
Capacity Factor – 2025 – Low Gas Price Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2025 – Low Gas Price Scenario (detailed UC Region=NWC)

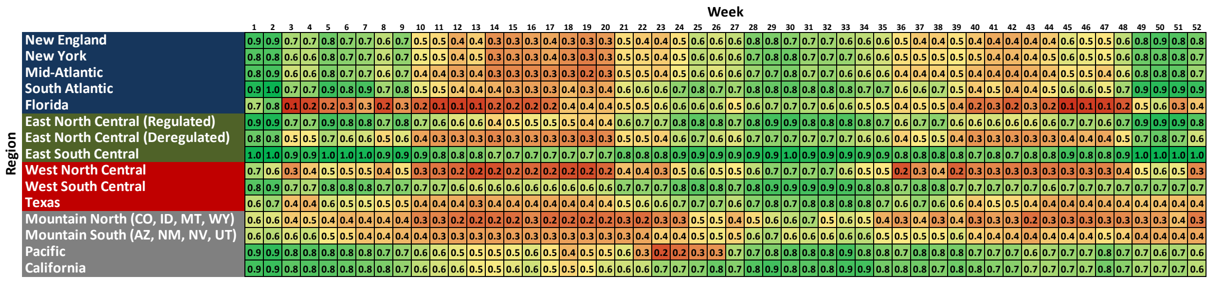


Figure C-119
Capacity Factor – 2025 – Low Gas Price Scenario – Natural Gas Combined Cycle

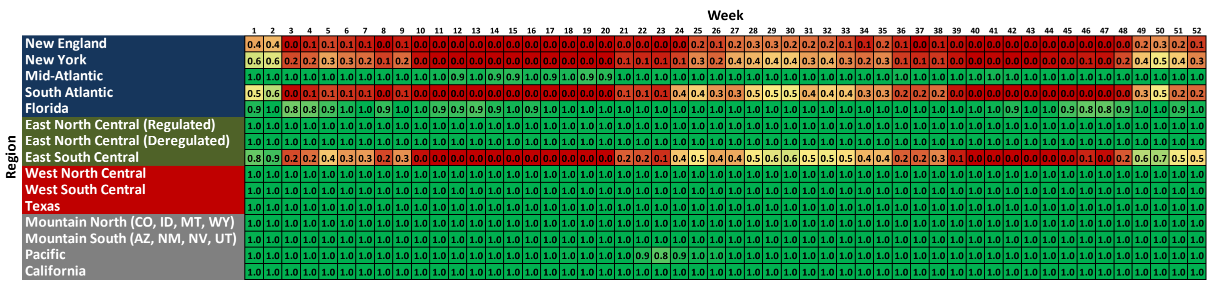


Figure C-120
Capacity Factor – 2025 – Low Gas Price Scenario – Coal

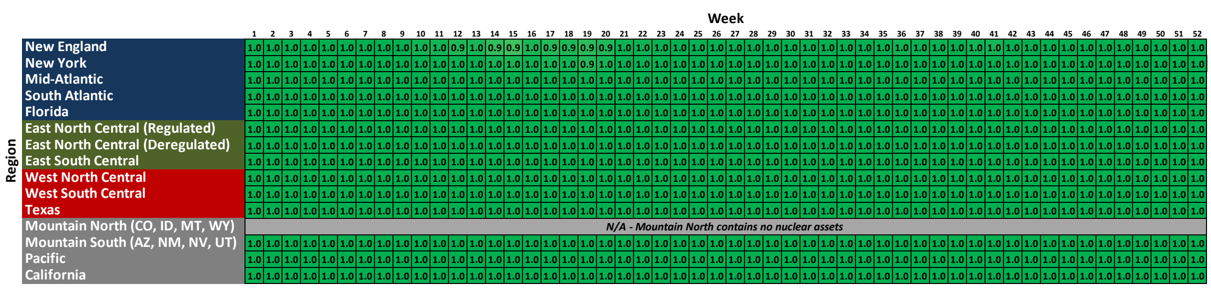


Figure C-121
Capacity Factor – 2025 – Low Gas Price Scenario – Nuclear

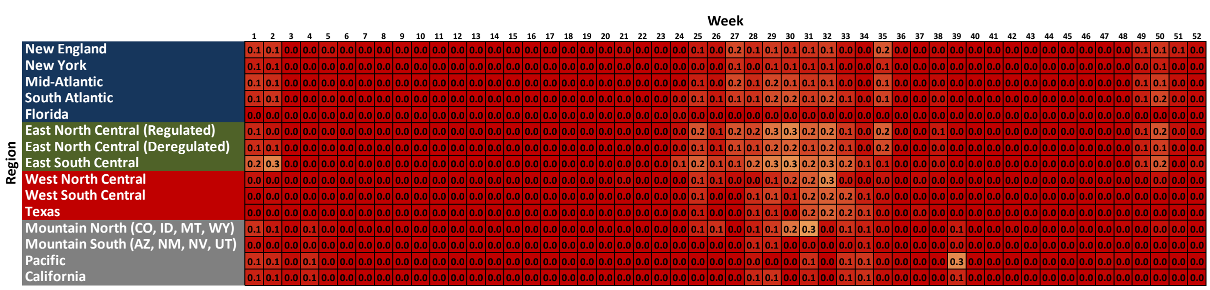


Figure C-122
Capacity Factor – 2025 – Low Gas Price Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2050 – Low Gas Price Scenario (detailed UC Region=TX)

Week (weeks 1–26)

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.9	0.8	0.7	0.7	0.8	0.7	0.7	0.7	0.7	0.4	0.4	0.3	0.4	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5
New York	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.9	0.7	0.8	0.7	0.8	0.6	0.6	0.6	0.7	0.7	0.6	0.7	0.8	0.8	0.8	0.8	0.9	0.9
Mid-Atlantic	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.7	0.7	0.4	0.4	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.4	0.4	0.4	0.5	0.6	0.6
South Atlantic	0.8	0.9	0.5	0.6	0.7	0.7	0.7	0.5	0.6	0.4	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.3	0.2	0.3	0.4	0.4	0.5	0.6	0.6	0.6
Florida	0.5	0.6	0.0	0.1	0.1	0.1	0.2	0.1	0.2	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.3	0.4	0.4	0.5	0.5	0.5	0.5
East North Central (Regulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.8	0.9	1.0	0.8	0.9	0.8	1.0	0.9	1.0	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	0.9	0.8	1.0	1.0	1.0	0.9	1.0	0.7	0.6	0.4	0.3	0.3	0.4	0.5	0.3	0.3	0.3	0.4	0.7	0.7	0.7	0.8	0.8	0.8
East South Central	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.8	0.7	0.8	0.8	0.8	0.8	0.9	0.9	0.9
West North Central	0.4	0.4	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.3	0.2
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0
Texas	0.8	0.9	0.5	0.4	0.6	0.5	0.5	0.4	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.2	0.3	0.3	0.4	0.6	0.7	0.7
Mountain North (CO, ID, MT, WY)	0.9	0.8	0.7	0.7	0.8	0.9	0.9	0.8	0.7	0.6	0.5	0.4	0.2	0.3	0.3	0.5	0.2	0.3	0.3	0.5	0.5	0.5	0.6	0.6	0.7	0.7
Mountain South (AZ, NM, NV, UT)	0.7	0.6	0.6	0.6	0.6	0.6	0.7	0.6	0.5	0.5	0.4	0.3	0.3	0.4	0.3	0.4	0.3	0.4	0.4	0.5	0.4	0.4	0.5	0.4	0.4	0.5
Pacific	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.7	0.7	0.8	0.8	0.7	0.7	0.8	0.8	0.8	0.7	0.6	0.6	0.6	0.6
California	0.8	0.8	0.9	0.8	0.8	0.9	0.7	0.8	0.7	0.7	0.7	0.7	0.6	0.7	0.7	0.7	0.6	0.6	0.7	0.7	0.7	0.7	0.8	0.7	0.7	0.8

Week (weeks 27–52)

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.6	0.7	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.4	0.3	0.3	0.5	0.3	0.2	0.3	0.3	0.3	0.4	0.3	0.3	0.5	0.7	0.8	0.8	0.7
New York	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9
Mid-Atlantic	0.6	0.7	0.8	0.8	0.7	0.7	0.7	0.6	0.6	0.5	0.4	0.4	0.6	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.6	0.9	0.9	0.9	0.8
South Atlantic	0.6	0.6	0.7	0.7	0.6	0.7	0.6	0.5	0.6	0.4	0.5	0.5	0.4	0.2	0.3	0.2	0.3	0.3	0.4	0.4	0.3	0.5	0.8	0.8	0.8	0.7
Florida	0.4	0.5	0.6	0.6	0.6	0.5	0.5	0.4	0.4	0.4	0.4	0.3	0.3	0.2	0.2	0.1	0.2	0.2	0.0	0.1	0.1	0.1	0.3	0.4	0.1	0.3
East North Central (Regulated)	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Deregulated)	0.8	0.9	0.9	1.0	0.9	0.9	0.9	0.8	0.8	0.7	0.8	0.9	0.8	0.7	0.8	0.7	0.6	0.7	0.8	0.8	0.8	0.8	1.0	1.0	1.0	1.0
East South Central	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9
West North Central	0.2	0.3	0.4	0.4	0.4	0.4	0.3	0.2	0.2	0.0	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.3	0.2	0.1
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Texas	0.5	0.7	0.8	0.8	0.8	0.9	0.9	0.8	0.6	0.4	0.6	0.5	0.3	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.4	0.5	0.5	0.4	0.3
Mountain North (CO, ID, MT, WY)	0.7	0.8	0.8	0.9	0.8	0.8	0.8	0.8	0.7	0.6	0.6	0.7	0.7	0.6	0.6	0.6	0.4	0.5	0.4	0.6	0.6	0.6	0.8	0.7	1.0	0.8
Mountain South (AZ, NM, NV, UT)	0.5	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.5	0.5	0.5	0.5	0.6	0.5	0.5	0.5	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.7	0.6
Pacific	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.9	0.8	0.9	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
California	0.8	0.8	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.8	0.8	0.8	0.8	0.7	0.8	0.8	0.9	0.8	0.8	0.8	0.9	0.8

Figure C-123
Capacity Factor – 2050 – Low Gas Price Scenario – Natural Gas Combined Cycle

Week (weeks 1–26)

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New York	0.3	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Mid-Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.9	1.0	1.0	1.0	1.0	1.0	1.0
South Atlantic	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0
Florida	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.3	0.2	0.2
East North Central (Regulated)	0.8	0.8	0.6	0.6	0.7	0.6	0.6	0.5	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.6	0.7	0.6
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	0.2	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.0
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Texas	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain North (CO, ID, MT, WY)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Pacific	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
California	0.6	0.6	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.3	0.3	0.2	0.2	0.1	0.1	0.2	0.1	0.1	0.2	0.3	0.2	0.2	0.2	0.2	0.3	0.3

Week (weeks 27–52)

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0
New York	0.1	0.1	0.2	0.2	0.1	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.0	0.0
Mid-Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
South Atlantic	0.1	0.1	0.3	0.3	0.2	0.2	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.0	0.0
Florida	0.2	0.3	0.4	0.4	0.3	0.3	0.3	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.0	0.0
East North Central (Regulated)	0.6	0.7	0.7	0.8	0.7	0.7	0.7	0.6	0.7	0.5	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.7	0.8	0.7	0.6
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	0.1	0.1	0.3	0.3	0.2	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Texas	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain North (CO, ID, MT, WY)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Pacific	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.4	0.5	0.4
California	0.3	0.3	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.5	0.4

Figure C-124
Capacity Factor – 2050 – Low Gas Price Scenario – Coal

Week (weeks 1–26)

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0
New York	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mid-Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
South Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Florida	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Regulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Texas	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain North (CO, ID, MT, WY)	*N/A - Mountain North contains no nuclear assets*																									
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
California	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Week (weeks 27–52)

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
New York	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mid-Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
South Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Florida	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Regulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Texas	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain North (CO, ID, MT, WY)																										
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
California	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Figure C-125
Capacity Factor – 2050 – Low Gas Price Scenario – Nuclear

Week (weeks 1–26)

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New York	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid-Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Atlantic	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Florida	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East North Central (Regulated)	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
East North Central (Deregulated)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East South Central	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
West North Central	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West South Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Texas	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain North (CO, ID, MT, WY)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain South (AZ, NM, NV, UT)	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pacific	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
California	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Week (weeks 27–52)

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New York	0.1	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
Mid-Atlantic	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
South Atlantic	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
Florida	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East North Central (Regulated)	0.1	0.1	0.2	0.2	0.1	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0
East North Central (Deregulated)	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East South Central	0.1	0.1	0.2	0.2	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
West North Central	0.0	0.0	0.1	0.1	0.1	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West South Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Texas	0.0	0.1	0.2	0.0	0.2	0.1	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain North (CO, ID, MT, WY)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain South (AZ, NM, NV, UT)	0.0	0.1	0.1	0.0	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pacific	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
California	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Figure C-126
Capacity Factor – 2050 – Low Gas Price Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2050 – Low Gas Price Scenario (detailed UC Region=NWC)

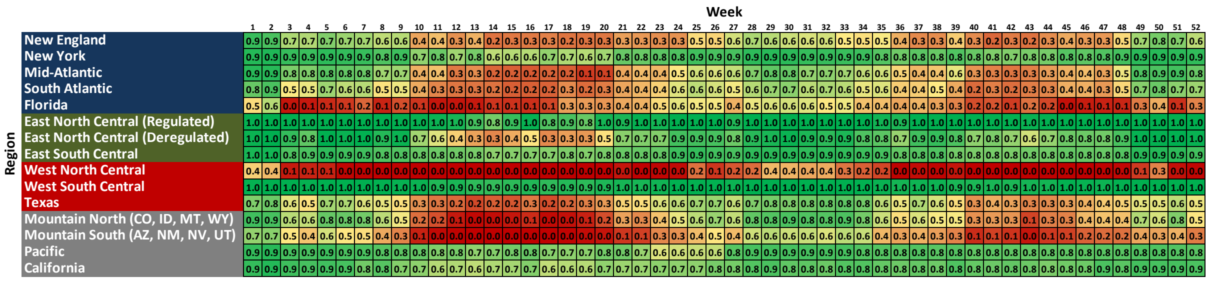


Figure C-127
Capacity Factor – 2050 – Low Gas Price Scenario – Natural Gas Combined Cycle

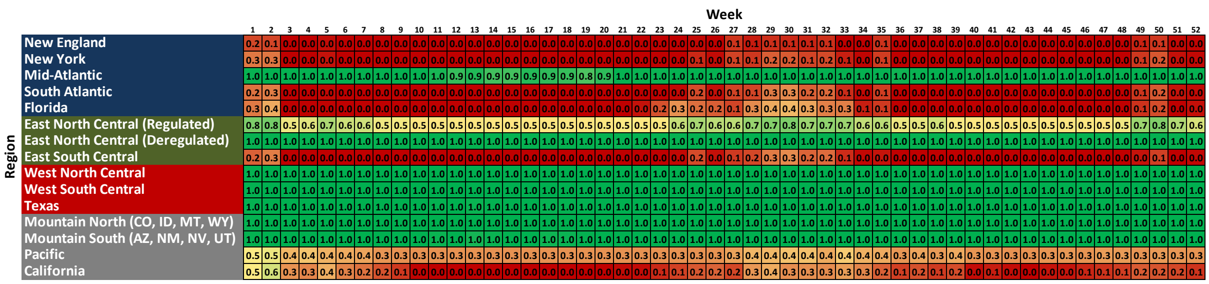


Figure C-128
Capacity Factor – 2050 – Low Gas Price Scenario – Coal

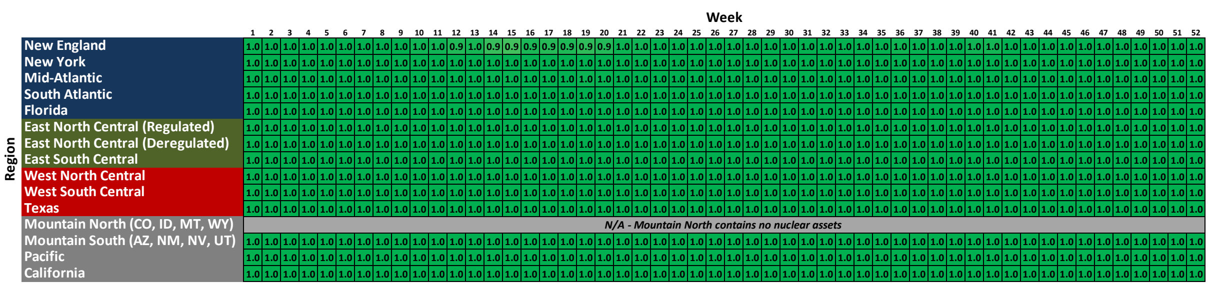


Figure C-129
Capacity Factor – 2050 – Low Gas Price Scenario – Nuclear

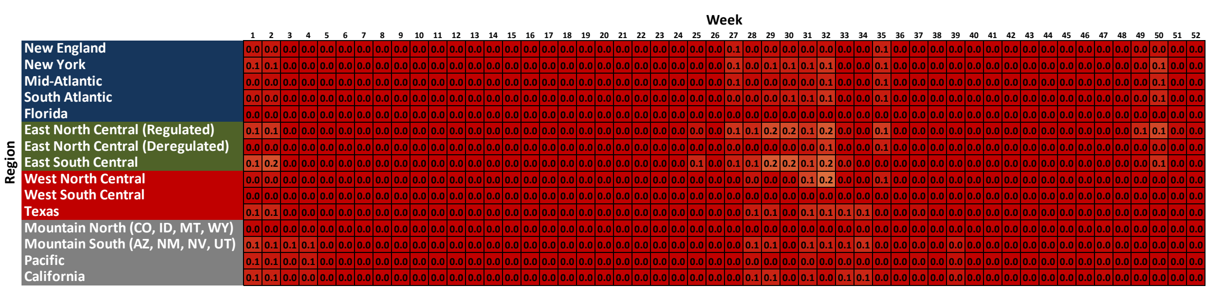


Figure C-130
Capacity Factor – 2050 – Low Gas Price Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2025 – High Gas Price Scenario (detailed UC Region=TX)

Week

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.6	0.6	0.3	0.3	0.5	0.4	0.3	0.3	0.4	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.2	0.2	0.2	0.4	0.3
New York	0.5	0.5	0.2	0.2	0.4	0.3	0.3	0.2	0.4	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.2	0.2	0.2	0.3	0.4	0.3
Mid-Atlantic	0.5	0.5	0.2	0.2	0.3	0.3	0.3	0.2	0.4	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.2	0.2	0.3	0.4	0.3
South Atlantic	0.5	0.6	0.1	0.1	0.4	0.3	0.3	0.2	0.4	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.2	0.4	0.5	0.4
Florida	0.3	0.5	0.0	0.0	0.1	0.1	0.2	0.1	0.2	0.2	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.4	0.4	0.3	0.4	0.4	0.5	0.5	0.5	0.5
East North Central (Regulated)	0.6	0.6	0.2	0.2	0.5	0.4	0.4	0.3	0.4	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.2	0.4	0.5	0.5
East North Central (Deregulated)	0.4	0.4	0.1	0.1	0.3	0.3	0.3	0.2	0.3	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.1	0.0	0.1	0.3	0.2	0.1	0.3	0.4	0.3
East South Central	0.8	0.8	0.4	0.4	0.7	0.7	0.7	0.5	0.7	0.5	0.4	0.3	0.3	0.3	0.4	0.4	0.3	0.4	0.3	0.4	0.5	0.5	0.5	0.6	0.6	0.6
West North Central	0.4	0.3	0.1	0.1	0.3	0.3	0.2	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.2	0.2	0.1	0.2	0.4	0.3
West South Central	0.5	0.6	0.3	0.2	0.5	0.5	0.5	0.4	0.4	0.2	0.3	0.2	0.1	0.2	0.2	0.3	0.2	0.2	0.2	0.3	0.4	0.4	0.4	0.5	0.6	0.5
Texas	0.4	0.5	0.2	0.1	0.4	0.4	0.3	0.3	0.2	0.0	0.1	0.0	0.0	0.0	0.0	0.2	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.4	0.5
Mountain North (CO, ID, MT, WY)	0.4	0.4	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.3
Mountain South (AZ, NM, NV, UT)	0.6	0.6	0.5	0.4	0.6	0.5	0.5	0.5	0.5	0.3	0.4	0.3	0.2	0.2	0.3	0.4	0.2	0.2	0.2	0.3	0.2	0.3	0.4	0.3	0.4	0.5
Pacific	0.8	0.8	0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.4	0.4	0.3	0.3	0.3	0.3	0.5	0.3	0.2	0.2	0.3	0.3	0.2	0.1	0.1	0.2	0.2
California	0.7	0.7	0.7	0.6	0.7	0.6	0.5	0.5	0.5	0.4	0.4	0.3	0.2	0.2	0.3	0.4	0.2	0.1	0.1	0.3	0.2	0.3	0.4	0.3	0.4	0.6

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.5	0.6	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.3	0.2	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.3	0.3	0.2	0.3	0.5	0.6	0.5	0.4
New York	0.4	0.5	0.5	0.5	0.4	0.5	0.4	0.3	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.2	0.3	0.4	0.5	0.4	0.3
Mid-Atlantic	0.4	0.4	0.5	0.5	0.4	0.5	0.4	0.3	0.4	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.4	0.5	0.4	0.3
South Atlantic	0.4	0.5	0.6	0.6	0.5	0.6	0.5	0.4	0.4	0.3	0.3	0.4	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.1	0.2	0.4	0.6	0.4	0.3
Florida	0.4	0.5	0.6	0.6	0.5	0.5	0.5	0.4	0.4	0.3	0.4	0.4	0.3	0.2	0.2	0.2	0.3	0.2	0.1	0.1	0.1	0.1	0.2	0.3	0.1	0.3
East North Central (Regulated)	0.4	0.5	0.6	0.6	0.5	0.6	0.6	0.4	0.5	0.3	0.4	0.4	0.3	0.3	0.3	0.3	0.2	0.3	0.3	0.3	0.2	0.3	0.5	0.6	0.5	0.4
East North Central (Deregulated)	0.3	0.4	0.5	0.5	0.4	0.5	0.5	0.3	0.4	0.2	0.2	0.3	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.2	0.1	0.2	0.4	0.4	0.3	0.2
East South Central	0.6	0.7	0.7	0.8	0.7	0.7	0.7	0.6	0.6	0.5	0.5	0.6	0.5	0.5	0.6	0.5	0.4	0.5	0.6	0.6	0.5	0.6	0.7	0.8	0.7	0.6
West North Central	0.3	0.4	0.5	0.5	0.5	0.5	0.4	0.3	0.3	0.2	0.2	0.3	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.2	0.1
West South Central	0.5	0.6	0.6	0.6	0.7	0.7	0.6	0.5	0.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.2	0.3	0.2	0.3	0.4	0.4	0.4	0.4
Texas	0.4	0.6	0.5	0.5	0.6	0.7	0.7	0.6	0.4	0.4	0.5	0.3	0.4	0.2	0.3	0.3	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.1
Mountain North (CO, ID, MT, WY)	0.2	0.3	0.4	0.5	0.6	0.4	0.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.1	0.2	0.2	0.1	0.2	0.3	0.2	0.2	0.2
Mountain South (AZ, NM, NV, UT)	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.6	0.5	0.5	0.5	0.4	0.4	0.4	0.5	0.4	0.4	0.4	0.4	0.4	0.4
Pacific	0.5	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.6	0.5	0.7	0.6	0.7	0.6	0.6	0.7	0.5	0.5	0.5	0.5	0.6	0.6	0.5	0.6	0.6	0.5
California	0.5	0.7	0.7	0.7	0.6	0.6	0.7	0.7	0.5	0.6	0.6	0.6	0.7	0.6	0.6	0.6	0.4	0.5	0.5	0.5	0.6	0.5	0.5	0.5	0.5	0.4

Figure C-131
Capacity Factor – 2025 – High Gas Price Scenario – Natural Gas Combined Cycle

Week

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.7	0.7	0.5	0.5	0.6	0.6	0.6	0.5	0.6	0.4	0.4	0.3	0.4	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.4	0.5	0.6	0.5
New York	1.0	1.0	0.9	0.8	1.0	0.9	0.9	0.9	1.0	0.8	0.8	0.7	0.8	0.6	0.7	0.8	0.8	0.6	0.5	0.6	0.8	0.8	0.7	0.8	0.9	0.9
Mid-Atlantic	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	1.0	0.9	0.9	0.8	0.9	1.0	1.0	0.9	1.0	1.0	1.0
South Atlantic	1.0	1.0	0.8	0.8	1.0	1.0	1.0	0.9	1.0	0.9	0.8	0.7	0.7	0.7	0.7	0.8	0.7	0.7	0.6	0.8	0.8	0.8	0.7	0.8	0.9	0.9
Florida	1.0	1.0	0.8	0.8	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Regulated)	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.8	0.9	0.9	1.0	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Texas	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.9	0.8	1.0	0.9	1.0	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain North (CO, ID, MT, WY)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	1.0	1.0	0.9	0.8	0.9	1.0	0.9	0.9	0.9	0.9	0.9	1.0
California	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.9	0.8	0.9	1.0	1.0	0.9	0.8	0.8	1.0	0.9	0.9	1.0	0.9	0.9	1.0

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.6	0.7	0.7	0.6	0.7	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6	0.7	0.7	0.7	0.6
New York	0.8	1.0	1.0	1.0	0.9	0.9	1.0	0.9	0.8	0.7	0.8	0.8	0.9	0.9	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0
Mid-Atlantic	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
South Atlantic	0.8	0.9	0.9	1.0	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.9	0.9	0.8	0.8	0.9	0.9	0.9	0.8	0.9	1.0	1.0	1.0	1.0
Florida	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	0.9	0.9	1.0	1.0	1.0	1.0	1.0
East North Central (Regulated)	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.9	0.9	1.0	1.0	1.0	1.0
Texas	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	1.0	0.9	0.9	1.0	1.0	1.0	0.9
Mountain North (CO, ID, MT, WY)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
California	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Figure C-132
Capacity Factor – 2025 – High Gas Price Scenario – Coal

Week

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0
New York	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0
Mid-Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
South Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Florida	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Regulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Texas	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain North (CO, ID, MT, WY)	N/A - Mountain North contains no nuclear assets																									
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
California	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
New York	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mid-Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
South Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Florida	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Regulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Texas	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain North (CO, ID, MT, WY)	N/A - Mountain North contains no nuclear assets																									
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
California	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0

Figure C-133
Capacity Factor – 2025 – High Gas Price Scenario – Nuclear

Week

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New York	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid-Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Florida	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East North Central (Regulated)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
East North Central (Deregulated)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
East South Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West North Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
West South Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Texas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain North (CO, ID, MT, WY)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain South (AZ, NM, NV, UT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pacific	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
California	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.1	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New York	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid-Atlantic	0.1	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Atlantic	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Florida	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East North Central (Regulated)	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East North Central (Deregulated)	0.1	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East South Central	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West North Central	0.0	0.1	0.1	0.2	0.2	0.2	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West South Central	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Texas	0.0	0.0	0.0	0.0	0.2	0.3	0.3	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain North (CO, ID, MT, WY)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain South (AZ, NM, NV, UT)	0.0	0.2	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pacific	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
California	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Figure C-134
Capacity Factor – 2025 – High Gas Price Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2025 – High Gas Price Scenario (detailed UC Region=NWC)

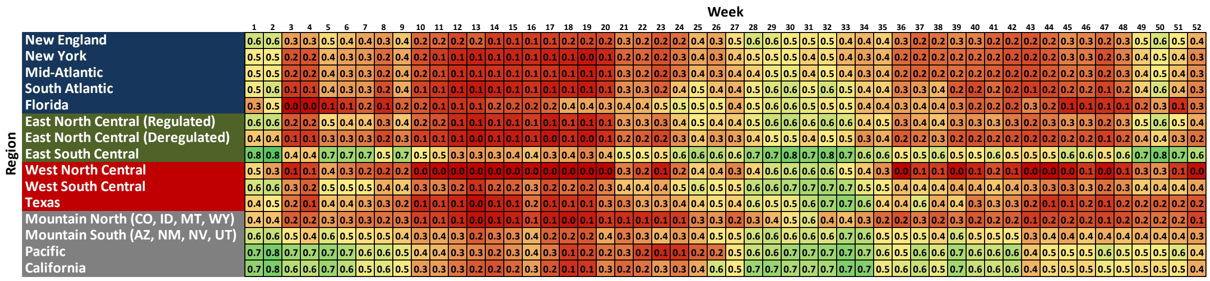


Figure C-135
Capacity Factor – 2025 – High Gas Price Scenario – Natural Gas Combined Cycle

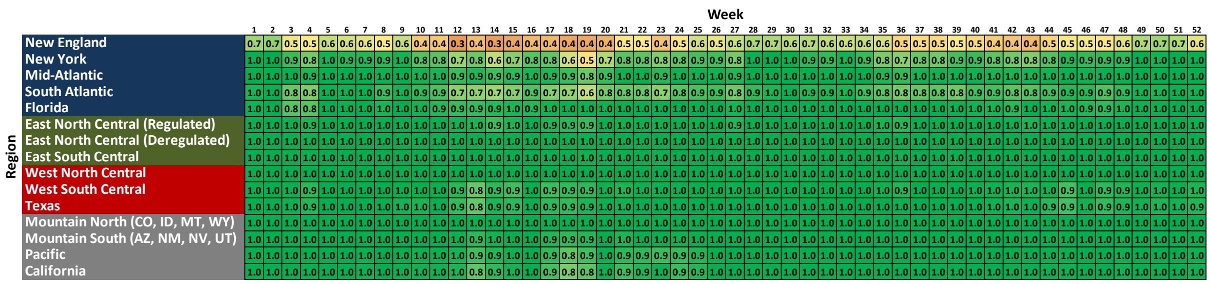


Figure C-136
Capacity Factor – 2025 – High Gas Price Scenario – Coal

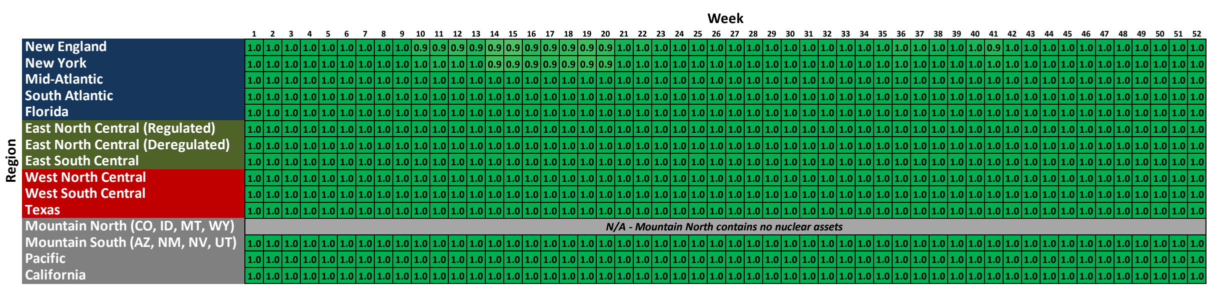


Figure C-137
Capacity Factor – 2025 – High Gas Price Scenario – Nuclear

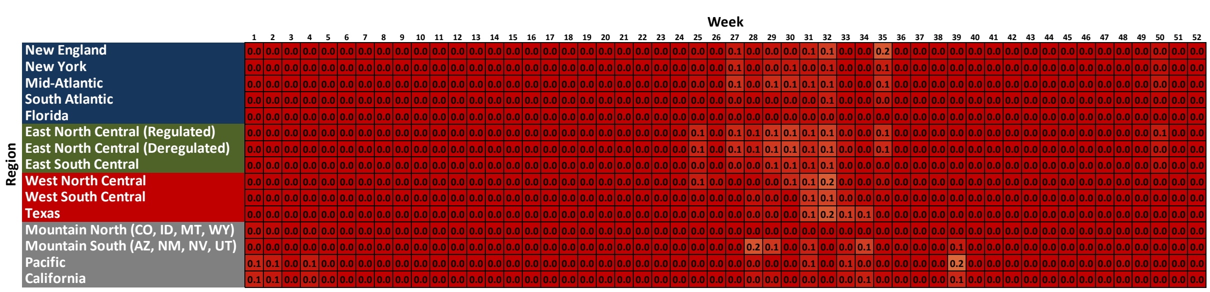


Figure C-138
Capacity Factor – 2025 – High Gas Price Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2050 – High Gas Price Scenario (detailed UC Region=TX)

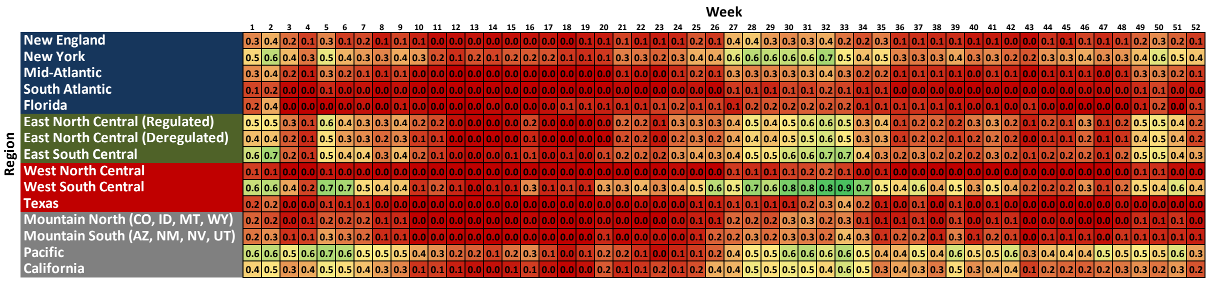


Figure C-139
Capacity Factor – 2050 – High Gas Price Scenario – Natural Gas Combined Cycle

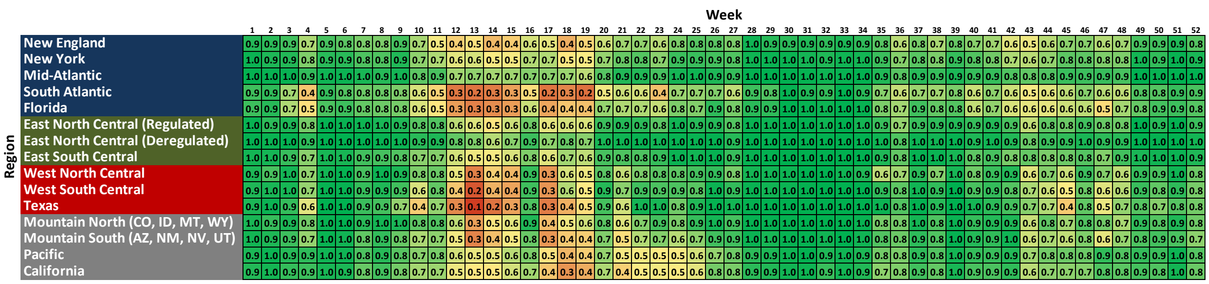


Figure C-140
Capacity Factor – 2050 – High Gas Price Scenario – Coal

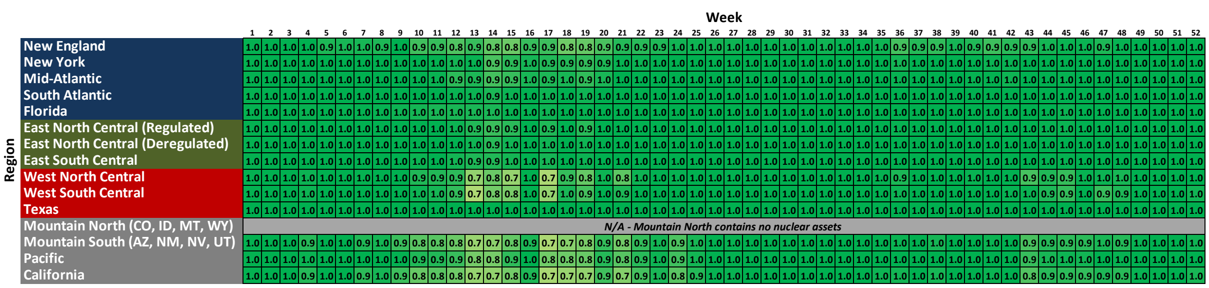


Figure C-141
Capacity Factor – 2050 – High Gas Price Scenario – Nuclear

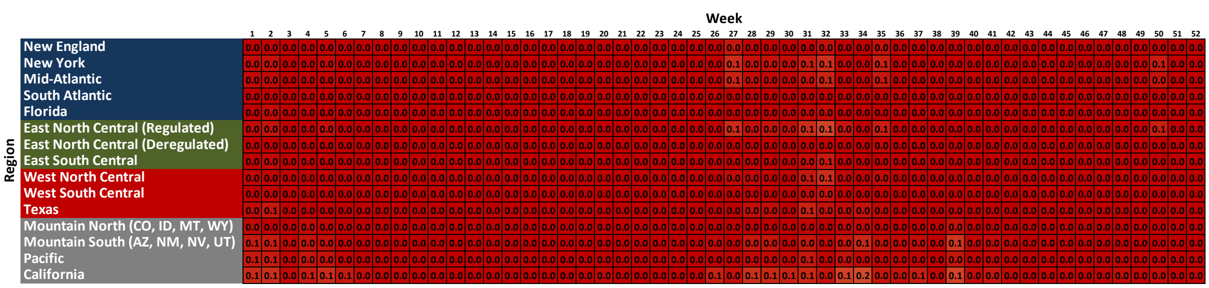
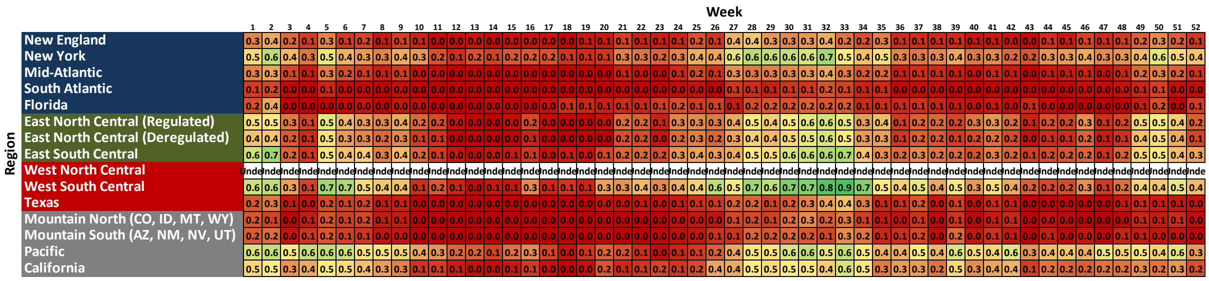


Figure C-142
Capacity Factor – 2050 – High Gas Price Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2050 – High Gas Price Scenario (detailed UC Region=NWC)



**Undefined values shown for West North Central region result from no NGCC capacity in this region in 2050.*

Figure C-143
Capacity Factor – 2050 – High Gas Price Scenario – Natural Gas Combined Cycle

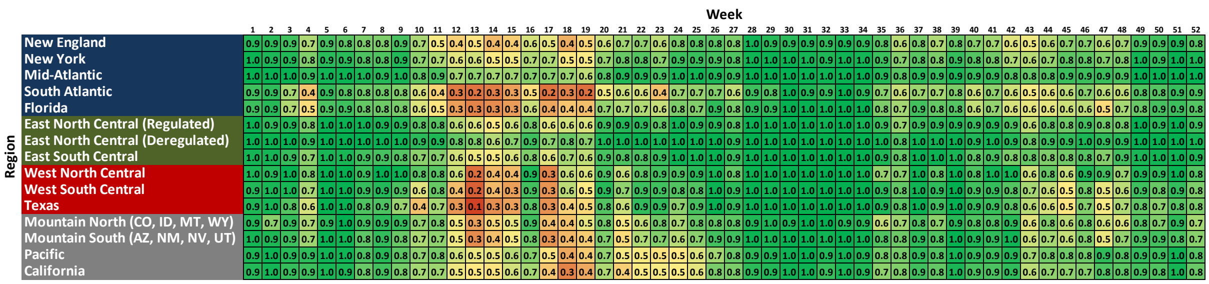


Figure C-144
Capacity Factor – 2050 – High Gas Price Scenario – Coal

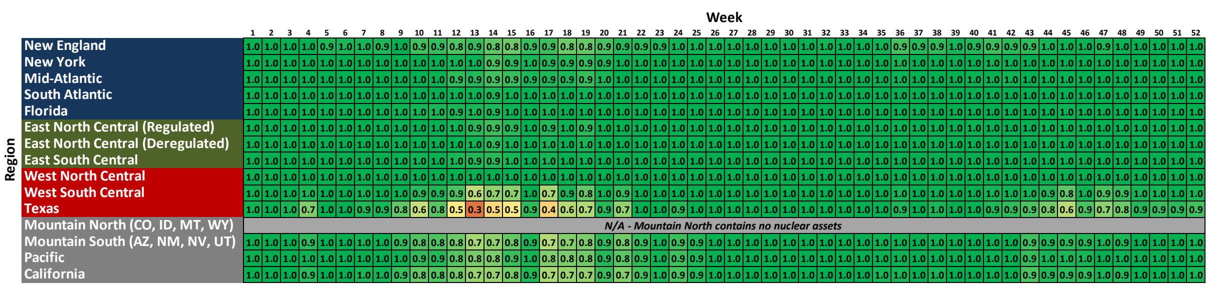


Figure C-145
Capacity Factor – 2050 – High Gas Price Scenario – Nuclear

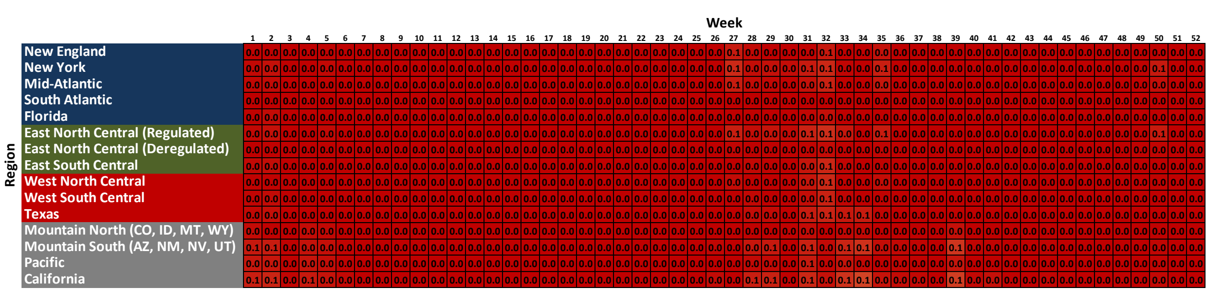


Figure C-146
Capacity Factor – 2050 – High Gas Price Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2025 – High Gas Price/No New Transmission Scenario (detailed UC Region=TX)

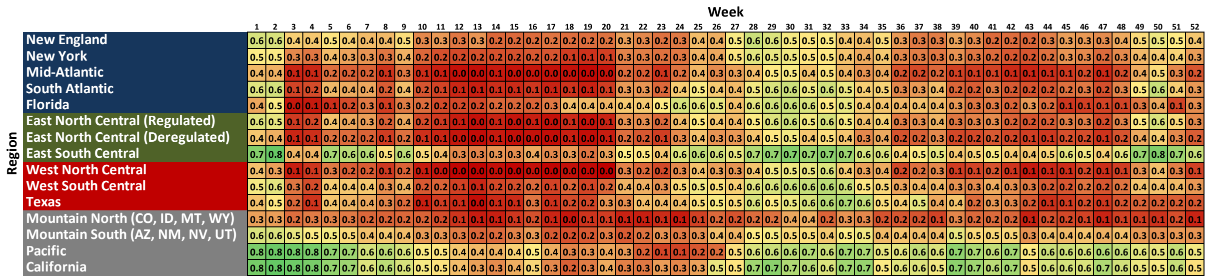


Figure C-147
Capacity Factor – 2025 – High Gas Price/No New Transmission Scenario – Natural Gas Combined Cycle

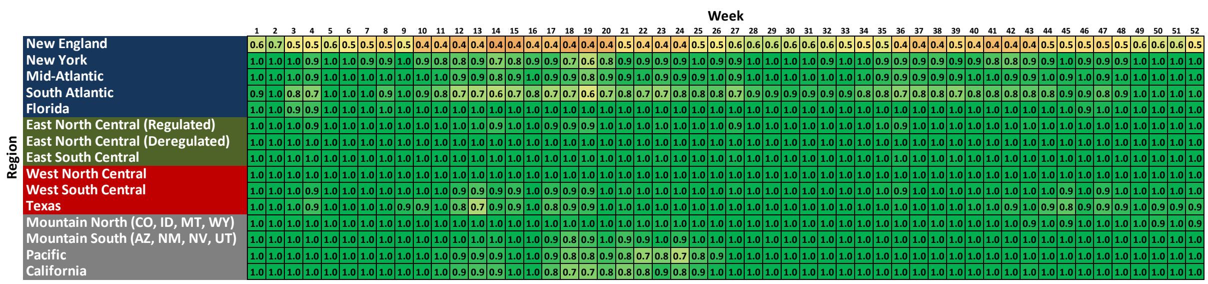


Figure C-148
Capacity Factor – 2025 – High Gas Price/ No New Transmission Scenario – Coal

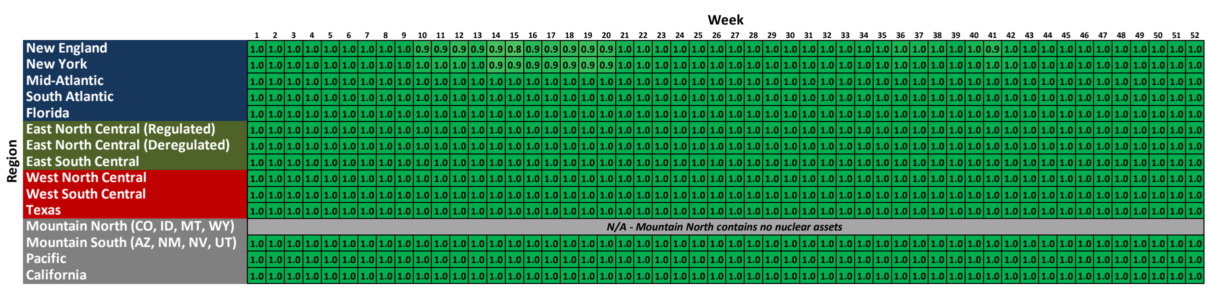


Figure C-149
Capacity Factor – 2025 – High Gas Price/ No New Transmission Scenario – Nuclear

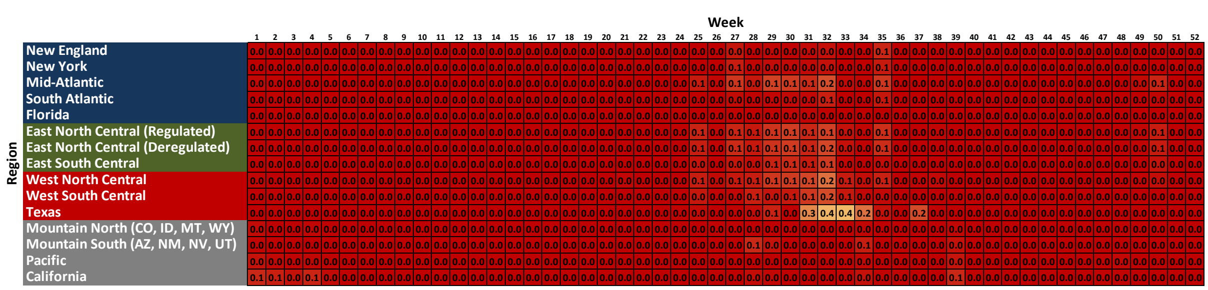


Figure C-150
Capacity Factor – 2025 – High Gas Price/ No New Transmission Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2025 – High Gas Price/No New Transmission Scenario (detailed UC Region=NWC)

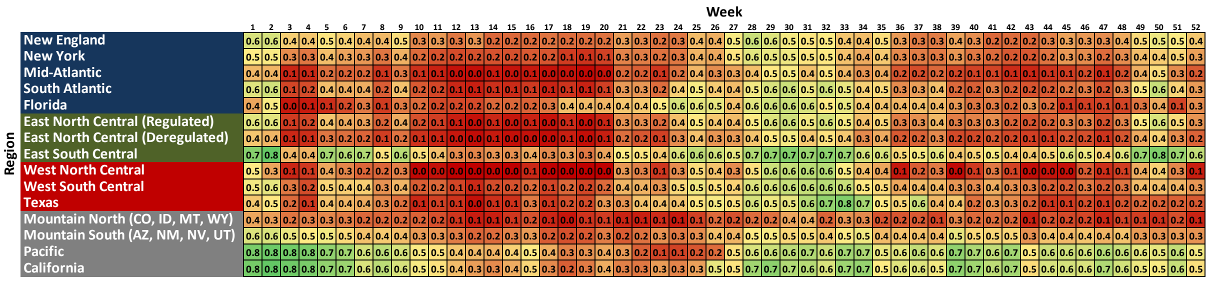


Figure C-151
Capacity Factor – 2025 – High Gas Price/No New Transmission Scenario – Natural Gas Combined Cycle

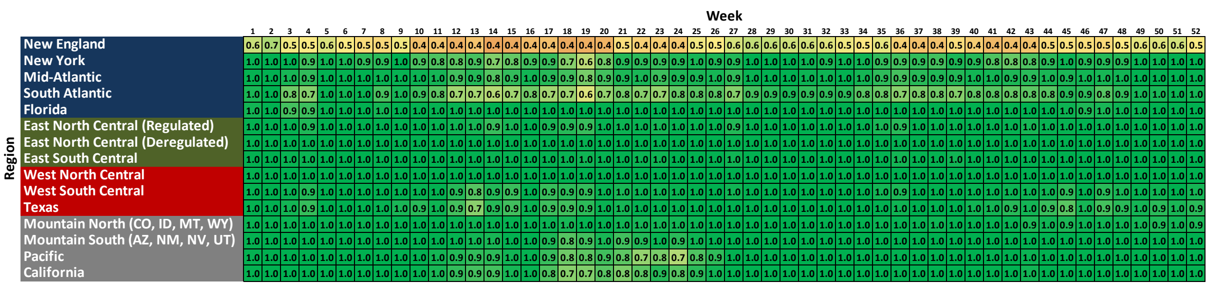


Figure C-152
Capacity Factor – 2025 – High Gas Price/ No New Transmission Scenario – Coal

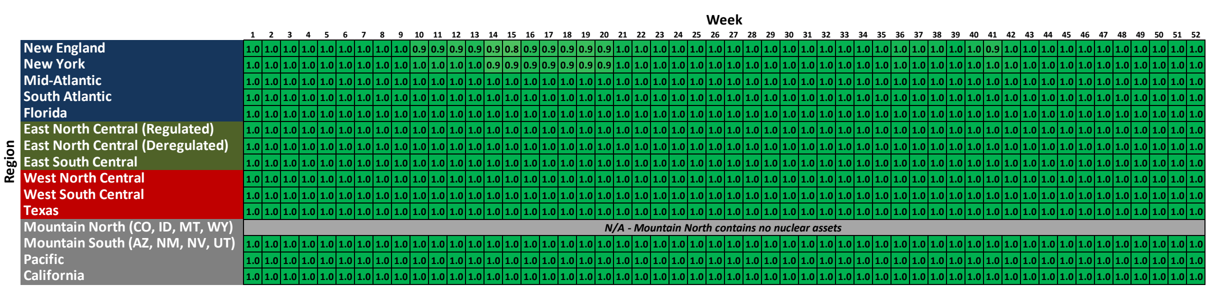


Figure C-153
Capacity Factor – 2025 – High Gas Price/ No New Transmission Scenario – Nuclear

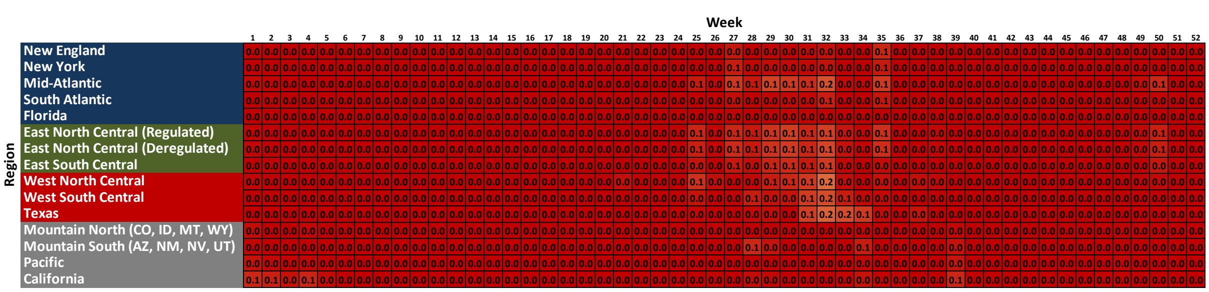


Figure C-154
Capacity Factor – 2025 – High Gas Price/ No New Transmission Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2050 – High Gas Price/No New Transmission Scenario (detailed UC Region=TX)

Week

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.3	0.4	0.3	0.2	0.3	0.2	0.2	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.2	0.1	0.1	0.1	0.2	0.2
New York	0.5	0.6	0.5	0.3	0.5	0.4	0.4	0.4	0.4	0.4	0.2	0.2	0.3	0.2	0.2	0.3	0.3	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4
Mid-Atlantic	0.4	0.4	0.2	0.1	0.4	0.3	0.2	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.2	0.2	0.2
South Atlantic	0.2	0.3	0.0	0.0	0.1	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Florida	0.3	0.5	0.0	0.0	0.1	0.1	0.2	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.2	0.2	0.2	0.2	0.3	0.4	0.3	0.4
East North Central (Regulated)	0.7	0.6	0.4	0.3	0.8	0.5	0.6	0.5	0.5	0.4	0.3	0.1	0.1	0.1	0.2	0.3	0.1	0.1	0.0	0.1	0.4	0.3	0.1	0.5	0.5	0.4
East North Central (Deregulated)	0.6	0.6	0.3	0.2	0.7	0.5	0.5	0.4	0.5	0.3	0.2	0.1	0.1	0.0	0.1	0.2	0.1	0.0	0.0	0.1	0.3	0.3	0.1	0.4	0.4	0.3
East South Central	0.7	0.8	0.3	0.2	0.6	0.5	0.6	0.4	0.5	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.2	0.2	0.4	0.4	0.3
West North Central	0.4	0.2	0.2	0.0	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West South Central	0.5	0.5	0.3	0.1	0.5	0.5	0.3	0.3	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.0	0.2	0.3	0.3	0.2	0.3	0.3	0.4
Texas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.2	0.2	0.3	0.0	0.0	0.0	0.0
Mountain North (CO, ID, MT, WY)	0.2	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.2	0.1	0.2	0.1	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.2	0.0	0.0	0.1	0.1	0.2	0.2
Mountain South (AZ, NM, NV, UT)	0.3	0.4	0.3	0.3	0.4	0.3	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.2	0.1	0.1	0.2	0.1	0.2	0.4
Pacific	0.8	0.9	0.8	0.9	0.8	0.8	0.7	0.8	0.7	0.6	0.6	0.5	0.5	0.5	0.6	0.6	0.5	0.4	0.5	0.5	0.5	0.3	0.2	0.2	0.3	0.3
California	0.6	0.7	0.6	0.7	0.6	0.6	0.5	0.6	0.5	0.4	0.4	0.3	0.3	0.3	0.3	0.4	0.2	0.2	0.3	0.4	0.3	0.3	0.4	0.4	0.4	0.6

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.5	0.5	0.4	0.3	0.4	0.4	0.3	0.2	0.4	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.1	0.2	0.3	0.4	0.3	0.2
New York	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.3	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.3	0.3	0.4	0.6	0.5	0.4
Mid-Atlantic	0.3	0.3	0.3	0.4	0.4	0.5	0.3	0.2	0.3	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.2	0.1	0.1	0.4	0.4	0.3	0.2
South Atlantic	0.1	0.1	0.1	0.2	0.1	0.2	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.3	0.1	0.1
Florida	0.2	0.4	0.4	0.4	0.4	0.3	0.4	0.3	0.3	0.2	0.3	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.2	0.3	0.1	0.3
East North Central (Regulated)	0.5	0.6	0.7	0.7	0.6	0.7	0.7	0.5	0.6	0.2	0.3	0.4	0.3	0.4	0.4	0.3	0.1	0.4	0.4	0.5	0.3	0.3	0.7	0.6	0.7	0.4
East North Central (Deregulated)	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.4	0.5	0.2	0.2	0.4	0.3	0.3	0.4	0.3	0.1	0.3	0.3	0.4	0.2	0.2	0.6	0.6	0.6	0.3
East South Central	0.3	0.5	0.5	0.6	0.6	0.6	0.6	0.4	0.3	0.2	0.3	0.3	0.2	0.2	0.3	0.2	0.2	0.3	0.4	0.4	0.3	0.4	0.6	0.6	0.6	0.5
West North Central	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.3	0.2	0.1
West South Central	0.4	0.5	0.4	0.5	0.6	0.6	0.6	0.5	0.2	0.3	0.4	0.2	0.3	0.2	0.3	0.2	0.1	0.1	0.1	0.2	0.1	0.2	0.4	0.4	0.4	0.3
Texas	0.4	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.5	0.1	0.0	0.0	0.0	0.0	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1
Mountain North (CO, ID, MT, WY)	0.2	0.4	0.4	0.6	0.6	0.1	0.3	0.3	0.1	0.1	0.1	0.1	0.3	0.2	0.2	0.3	0.1	0.2	0.2	0.1	0.0	0.0	0.2	0.1	0.2	0.0
Mountain South (AZ, NM, NV, UT)	0.3	0.4	0.4	0.4	0.3	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.4	0.2	0.2	0.3	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.1
Pacific	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.7	0.7	0.8	0.8	0.7	0.8	0.6	0.7	0.7	0.7	0.8	0.7	0.8	0.7	0.9	0.7
California	0.5	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.4	0.5	0.5	0.5	0.6	0.5	0.5	0.6	0.4	0.5	0.5	0.5	0.6	0.5	0.5	0.5	0.6	0.4

Figure C-155
Capacity Factor – 2050 – High Gas Price/No New Transmission Scenario – Natural Gas Combined Cycle

Week

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.9	0.7	0.7	0.7	0.7	0.6	0.6	0.8	0.7	0.6	0.6	0.7	0.8	0.8	0.8	0.8	0.9	0.8
New York	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9	1.0	0.8	0.8	0.7	0.8	0.7	0.7	0.7	0.7	0.7	0.6	0.8	0.9	0.9	0.8	0.9	0.9	0.9
Mid-Atlantic	1.0	1.0	1.0	0.9	1.0	1.0	1.0	0.9	1.0	0.9	0.9	0.7	0.8	0.7	0.7	0.8	0.7	0.7	0.6	0.8	0.9	0.9	0.8	1.0	1.0	0.9
South Atlantic	0.9	0.9	0.7	0.6	0.9	0.9	0.9	0.8	0.8	0.7	0.6	0.4	0.4	0.3	0.4	0.5	0.4	0.4	0.3	0.5	0.7	0.7	0.5	0.9	0.9	0.8
Florida	0.8	0.9	0.7	0.6	0.8	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.7	0.9	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.0
East North Central (Regulated)	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.8	0.8	0.7	0.7	0.9	0.7	0.8	0.7	0.9	1.0	1.0	0.9	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.8	0.8	0.9	0.9	0.9	0.8	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	1.0	1.0	0.9	0.8	1.0	1.0	1.0	0.9	0.9	0.8	0.9	0.7	0.7	0.6	0.7	0.7	0.7	0.8	0.7	0.9	0.9	0.9	0.9	1.0	1.0	1.0
West North Central	1.0	0.9	1.0	0.8	0.9	1.0	0.9	1.0	0.9	0.7	0.8	0.5	0.3	0.5	0.4	0.8	0.3	0.6	0.5	0.8	0.6	0.7	0.7	0.8	0.8	0.9
West South Central	0.9	1.0	1.0	0.7	0.9	1.0	0.9	0.9	0.9	0.6	0.7	0.4	0.2	0.4	0.3	0.9	0.3	0.6	0.5	0.9	0.7	0.8	0.8	0.9	0.8	1.0
Texas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.3	0.6	0.3	0.1	0.3	0.3	0.8	0.3	0.4	0.4	0.8	0.6	0.9	0.0	0.0	0.0	0.0
Mountain North (CO, ID, MT, WY)	0.7	0.6	0.7	0.7	0.8	0.9	0.8	0.8	0.9	0.9	0.8	0.6	0.5	0.5	0.7	0.9	0.5	0.5	0.8	0.8	0.6	0.7	0.8	0.7	0.9	0.9
Mountain South (AZ, NM, NV, UT)	0.9	0.9	0.9	0.7	0.9	0.9	0.8	0.8	0.8	0.7	0.7	0.6	0.5	0.6	0.7	0.8	0.5	0.5	0.6	0.7	0.6	0.7	0.8	0.7	0.7	0.8
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.9	0.8	0.8	0.7	0.8	0.8	0.8	0.9	0.7	0.6	0.7	0.8	0.7	0.7	0.6	0.6	0.7	0.7
California	0.9	1.0	1.0	1.0	0.9	0.9	0.8	0.9	0.8	0.8	0.7	0.7	0.7	0.8	0.8	0.9	0.7	0.6	0.7	0.7	0.6	0.7	0.7	0.7	0.7	0.8

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.9	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.7	0.8	0.9	0.7	0.7	0.7	0.8	0.9	0.8	0.8	0.8	0.9	0.9	1.0	0.9
New York	0.9	1.0	1.0	1.0	1.0	0.9	1.0	0.9	0.9	0.8	0.8	0.8	0.9	0.9	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0
Mid-Atlantic	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0
South Atlantic	0.6	0.9	0.9	1.0	1.0	0.9	1.0	0.9	0.8	0.7	0.7	0.8	0.7	0.7	0.8	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.9	0.9	1.0	0.9
Florida	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	1.0	0.9	0.9	0.8	0.9	0.8	0.9	0.9	0.7	0.8	0.8	0.8	0.8	0.9	0.8	0.9
East North Central (Regulated)	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.8	1.0	1.0	1.0	1.0	1.0	0.9	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.8	1.0	1.0	0.9	0.8	0.9	0.8	0.9	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.0
West North Central	0.8	0.9	0.9	0.9	1.0	1.0	0.9	0.9	0.7	0.7	0.9	0.7	0.9	0.7	0.9	0.9	0.7	0.7	0.6	0.9	0.8	0.7	0.9	0.9	1.0	0.9
West South Central	0.8	1.0	0.9	0.9	1.0	1.0	1.0	1.0	0.8	0.8	0.9	0.8	0.9	0.8	0.9	0.8	0.6	0.6	0.4	0.8	0.5	0.6	0.9	0.8	0.9	0.7
Texas	0.6	0.7	0.7	0.7	0.8	0.8	0.9	0.8	0.7	0.1	0.0	0.0	0.0	0.3	0.8	0.8	0.6	0.5	0.4	0.7	0.5	0.6	0.8	0.7	0.8	0.7
Mountain North (CO, ID, MT, WY)	0.9	0.9	1.0	1.0	1.0	0.9	0.9	0.9	0.8	0.7	0.8	0.7	0.9	0.9	0.8	0.8	0.5	0.7	0.7	0.7	0.5	0.5	0.7	0.6	0.8	0.6
Mountain South (AZ, NM, NV, UT)	0.8	0.9	0.9	0.9	0.9	0.9	1.0	0.9	0.8	0.8	0.9	0.8	1.0	1.0	0.9	1.0	0.7	0.8	0.7	0.8	0.7	0.8	0.8	0.8	0.8	0.8
Pacific	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.9	0.9	1.0	1.0	0.9	1.0	0.8	0.9	0.9	0.9	1.0	0.9	1.0	1.0	1.0	0.9
California	0.8	0.9	0.9	0.8	0.9	0.8	0.9	0.9	0.8	0.8	0.8	0.8	0.9	0.9	0.8	0.9	0.8	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.0	0.9

Figure C-156
Capacity Factor – 2050 – High Gas Price/ No New Transmission Scenario – Coal

Week

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	1.0	0.8	0.9	0.8	0.9	0.8	0.8	0.9	0.9	0.7	0.8	0.8	0.9	0.9	0.9	0.9	1.0	0.9
New York	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	1.0	0.8	0.8	0.9	0.9	0.8	0.8	0.9	1.0	0.9	1.0	1.0	1.0	1.0
Mid-Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0
South Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Florida	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Regulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.8	0.8	0.7	1.0	0.8	1.0	0.8	1.0	0.9	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.8	0.9	0.8	1.0	0.9	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Texas	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain North (CO, ID, MT, WY)	*N/A - Mountain North contains no nuclear assets*																									
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	0.9	1.0	1.0	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.7	0.8	0.9	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.8	0.9	0.9
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.9	0.9	1.0	1.0	0.9	0.8	0.8	0.8	0.8	0.8	0.9	0.8	0.9	0.9
California	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.8	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.9

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.8	0.9	0.9	0.9	0.9	0.8	0.9	0.9	0.9	1.0	0.9	0.9	1.0	1.0	1.0	1.0	1.0
New York	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mid-Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
South Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Florida	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Regulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0
Texas	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mountain North (CO, ID, MT, WY)	*N/A - Mountain North contains no nuclear assets*																									
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
California	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	1.0	0.9	1.0	1.0	0.9	1.0	0.9	0.9	0.9	0.9	1.0	0.9	1.0	1.0	1.0	1.0

Figure C-157
Capacity Factor – 2050 – High Gas Price/ No New Transmission Scenario – Nuclear

Week

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New York	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid-Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Florida	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East North Central (Regulated)	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East North Central (Deregulated)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East South Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West North Central	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West South Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Texas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain North (CO, ID, MT, WY)	0.1	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Mountain South (AZ, NM, NV, UT)	0.1	0.1	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Pacific	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
California	0.2	0.2	0.1	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.2

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New York	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid-Atlantic	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
South Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Florida	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East North Central (Regulated)	0.1	0.0	0.1	0.1	0.1	0.2	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
East North Central (Deregulated)	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East South Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West North Central	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0
West South Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Texas	0.4	0.5	0.5	0.5	0.5	0.6	0.5	0.6	0.5	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain North (CO, ID, MT, WY)	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain South (AZ, NM, NV, UT)	0.0	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pacific	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
California	0.1	0.2	0.2	0.2	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.0	0.2	0.0	0.1	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0

Figure C-158
Capacity Factor – 2050 – High Gas Price/ No New Transmission Scenario – Combustion Turbine

Capacity Factor Heat Maps – 2050 – High Gas Price/No New Transmission Scenario (detailed UC Region=NWC)

Week (weeks 1–26)

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.3	0.4	0.3	0.2	0.3	0.2	0.2	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.2	0.1	0.1	0.1	0.2	0.2
New York	0.5	0.6	0.5	0.3	0.5	0.4	0.4	0.4	0.4	0.4	0.2	0.2	0.3	0.2	0.2	0.3	0.3	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4
Mid-Atlantic	0.3	0.4	0.2	0.1	0.4	0.3	0.2	0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.2	0.2	0.2
South Atlantic	0.2	0.3	0.0	0.0	0.1	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0
Florida	0.3	0.5	0.0	0.0	0.1	0.1	0.2	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.2	0.2	0.2	0.2	0.3	0.4	0.3	0.4
East North Central (Regulated)	0.7	0.6	0.4	0.3	0.8	0.5	0.6	0.5	0.5	0.4	0.3	0.1	0.1	0.1	0.2	0.3	0.1	0.1	0.0	0.1	0.4	0.3	0.1	0.5	0.5	0.4
East North Central (Deregulated)	0.6	0.6	0.3	0.2	0.7	0.5	0.5	0.4	0.5	0.3	0.2	0.1	0.1	0.0	0.1	0.2	0.1	0.0	0.0	0.1	0.3	0.3	0.1	0.4	0.4	0.3
East South Central	0.7	0.8	0.3	0.2	0.6	0.5	0.6	0.4	0.5	0.3	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.2	0.2	0.4	0.4	0.3
West North Central	0.3	0.2	0.2	0.0	0.2	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West South Central	0.5	0.5	0.3	0.1	0.5	0.4	0.3	0.3	0.3	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.0	0.2	0.3	0.3	0.2	0.3	0.3	0.4
Texas	0.3	0.4	0.2	0.1	0.4	0.3	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.0	0.2	0.2	0.3	0.2	0.2	0.3	0.4
Mountain North (CO, ID, MT, WY)	0.2	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.2	0.1	0.2	0.1	0.0	0.0	0.1	0.1	0.0	0.0	0.1	0.2	0.0	0.0	0.1	0.1	0.2	0.2
Mountain South (AZ, NM, NV, UT)	0.3	0.4	0.2	0.3	0.4	0.3	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.2	0.1	0.1	0.2	0.1	0.2	0.4
Pacific	0.8	0.9	0.8	0.8	0.8	0.8	0.7	0.8	0.7	0.6	0.6	0.5	0.5	0.5	0.6	0.6	0.5	0.4	0.5	0.5	0.5	0.3	0.2	0.2	0.3	0.3
California	0.6	0.7	0.6	0.7	0.6	0.6	0.5	0.6	0.5	0.4	0.4	0.3	0.3	0.3	0.3	0.4	0.2	0.2	0.3	0.4	0.3	0.4	0.4	0.4	0.4	0.6

Week (weeks 27–52)

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.5	0.5	0.4	0.3	0.4	0.4	0.3	0.2	0.4	0.2	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.1	0.2	0.3	0.4	0.3	0.2
New York	0.6	0.6	0.6	0.6	0.6	0.6	0.5	0.5	0.5	0.3	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.3	0.3	0.4	0.6	0.5	0.4
Mid-Atlantic	0.3	0.3	0.3	0.4	0.4	0.5	0.3	0.2	0.3	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.2	0.1	0.1	0.3	0.4	0.3	0.2
South Atlantic	0.1	0.1	0.1	0.2	0.1	0.2	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.2	0.3	0.1	0.1
Florida	0.2	0.4	0.4	0.4	0.4	0.3	0.4	0.3	0.3	0.2	0.3	0.2	0.2	0.2	0.2	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.2	0.3	0.1	0.3
East North Central (Regulated)	0.5	0.6	0.7	0.7	0.6	0.7	0.7	0.5	0.6	0.2	0.3	0.4	0.3	0.4	0.4	0.3	0.1	0.4	0.4	0.5	0.3	0.3	0.6	0.6	0.7	0.4
East North Central (Deregulated)	0.4	0.6	0.6	0.6	0.6	0.6	0.6	0.4	0.5	0.2	0.2	0.4	0.3	0.3	0.4	0.3	0.1	0.3	0.3	0.4	0.2	0.2	0.6	0.6	0.6	0.3
East South Central	0.3	0.5	0.5	0.6	0.6	0.6	0.6	0.4	0.3	0.2	0.3	0.3	0.2	0.2	0.3	0.2	0.2	0.3	0.4	0.4	0.3	0.4	0.6	0.6	0.6	0.5
West North Central	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.3	0.3	0.2	0.1
West South Central	0.4	0.6	0.4	0.6	0.6	0.7	0.7	0.5	0.3	0.3	0.4	0.2	0.3	0.2	0.3	0.2	0.1	0.1	0.1	0.2	0.1	0.2	0.4	0.4	0.4	0.3
Texas	0.4	0.4	0.3	0.4	0.5	0.6	0.7	0.5	0.3	0.3	0.5	0.2	0.3	0.1	0.2	0.2	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Mountain North (CO, ID, MT, WY)	0.2	0.4	0.4	0.6	0.6	0.1	0.3	0.3	0.1	0.1	0.1	0.1	0.3	0.2	0.2	0.3	0.0	0.2	0.2	0.1	0.0	0.0	0.2	0.1	0.2	0.0
Mountain South (AZ, NM, NV, UT)	0.3	0.4	0.4	0.4	0.3	0.2	0.3	0.3	0.2	0.2	0.2	0.2	0.4	0.2	0.2	0.2	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.2	0.1
Pacific	0.6	0.7	0.6	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.7	0.7	0.8	0.8	0.7	0.8	0.6	0.7	0.7	0.7	0.8	0.7	0.8	0.7	0.9	0.7
California	0.5	0.6	0.6	0.6	0.6	0.5	0.6	0.6	0.4	0.5	0.5	0.5	0.6	0.5	0.5	0.6	0.4	0.5	0.5	0.5	0.6	0.5	0.5	0.5	0.6	0.4

Figure C-159
Capacity Factor – 2050 – High Gas Price/No New Transmission Scenario – Natural Gas Combined Cycle

Week (weeks 1–26)

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.9	0.7	0.7	0.7	0.7	0.6	0.6	0.8	0.7	0.6	0.6	0.7	0.8	0.8	0.8	0.8	0.9	0.8
New York	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9	1.0	0.8	0.8	0.7	0.8	0.7	0.7	0.7	0.7	0.7	0.6	0.8	0.9	0.9	0.8	0.9	0.9	0.9
Mid-Atlantic	1.0	1.0	1.0	0.9	1.0	1.0	1.0	0.9	1.0	0.9	0.9	0.7	0.8	0.7	0.7	0.8	0.7	0.7	0.6	0.8	0.9	0.9	0.8	1.0	1.0	0.9
South Atlantic	0.9	0.9	0.7	0.6	0.9	0.9	0.9	0.8	0.8	0.7	0.6	0.4	0.4	0.4	0.4	0.5	0.4	0.4	0.3	0.5	0.7	0.7	0.5	0.9	0.9	0.8
Florida	0.8	0.9	0.7	0.6	0.8	0.8	0.8	0.8	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.8	0.7	0.9	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.0
East North Central (Regulated)	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.8	0.8	0.7	0.7	0.9	0.7	0.8	0.7	0.9	1.0	1.0	0.9	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.8	0.8	0.9	0.9	0.9	0.8	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	1.0	1.0	0.9	0.8	1.0	1.0	1.0	0.9	0.9	0.8	0.9	0.7	0.7	0.6	0.7	0.7	0.7	0.8	0.7	0.9	0.9	0.9	0.9	1.0	1.0	1.0
West North Central	1.0	0.9	1.0	0.8	1.0	1.0	0.9	1.0	0.9	0.8	0.8	0.5	0.3	0.4	0.3	0.8	0.3	0.6	0.5	0.8	0.6	0.7	0.7	0.8	0.8	0.9
West South Central	0.9	0.9	0.9	0.6	0.9	1.0	0.9	0.9	0.8	0.5	0.7	0.5	0.2	0.4	0.4	0.9	0.3	0.7	0.5	0.9	0.7	0.8	0.8	0.8	0.8	1.0
Texas	0.9	0.9	0.7	0.5	1.0	1.0	0.8	0.8	0.6	0.3	0.5	0.3	0.1	0.3	0.3	0.7	0.3	0.4	0.4	0.8	0.6	0.8	0.8	0.7	0.8	1.0
Mountain North (CO, ID, MT, WY)	0.7	0.6	0.6	0.7	0.8	0.9	0.8	0.8	0.9	0.9	0.8	0.6	0.4	0.5	0.7	0.9	0.5	0.5	0.8	0.8	0.6	0.7	0.8	0.7	0.8	0.9
Mountain South (AZ, NM, NV, UT)	0.9	0.9	0.9	0.7	0.9	0.9	0.8	0.8	0.8	0.7	0.7	0.6	0.5	0.6	0.7	0.8	0.5	0.5	0.6	0.7	0.6	0.7	0.8	0.7	0.7	0.8
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.9	0.8	0.8	0.7	0.8	0.8	0.8	0.9	0.7	0.6	0.7	0.8	0.7	0.7	0.6	0.6	0.7	0.7
California	0.9	1.0	1.0	1.0	0.9	0.9	0.8	0.9	0.8	0.8	0.7	0.7	0.7	0.8	0.8	0.9	0.7	0.6	0.7	0.7	0.6	0.7	0.7	0.7	0.7	0.8

Week (weeks 27–52)

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.9	1.0	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	0.7	0.8	0.9	0.7	0.7	0.7	0.8	0.9	0.8	0.8	0.8	0.9	0.9	1.0	0.9
New York	0.9	1.0	1.0	1.0	1.0	0.9	1.0	0.9	0.9	0.8	0.8	0.8	0.9	0.9	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0
Mid-Atlantic	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0
South Atlantic	0.6	0.9	0.9	1.0	1.0	0.9	1.0	0.9	0.8	0.7	0.7	0.8	0.7	0.7	0.8	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.9	0.9	1.0	0.9
Florida	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	1.0	0.9	0.9	0.8	0.9	0.8	0.9	0.9	0.7	0.8	0.8	0.8	0.8	0.9	0.8	0.9
East North Central (Regulated)	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.8	1.0	1.0	1.0	1.0	1.0	0.9	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.8	1.0	1.0	0.9	0.8	0.9	0.8	0.9	0.8	0.8	0.9	0.9	0.9	1.0	1.0	1.0	1.0
West North Central	0.8	0.9	0.9	0.9	1.0	1.0	0.9	0.9	0.7	0.7	0.9	0.7	0.9	0.8	0.9	0.9	0.7	0.8	0.6	0.9	0.8	0.7	0.9	0.9	1.0	0.9
West South Central	0.9	1.0	0.9	0.9	1.0	1.0	1.0	1.0	0.8	0.8	0.9	0.8	0.9	0.8	0.9	0.8	0.7	0.6	0.5	0.8	0.5	0.6	0.9	0.8	0.9	0.7
Texas	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	0.9	0.8	1.0	0.9	1.0	0.7	0.8	0.7	0.6	0.4	0.4	0.7	0.4	0.6	0.7	0.7	0.8	0.7
Mountain North (CO, ID, MT, WY)	0.9	0.9	0.9	1.0	1.0	0.9	0.9	0.9	0.8	0.7	0.8	0.7	0.9	0.9	0.8	0.8	0.5	0.7	0.7	0.7	0.5	0.5	0.7	0.6	0.8	0.6
Mountain South (AZ, NM, NV, UT)	0.8	0.9	0.9	0.9	0.9	0.9	1.0	0.9	0.8	0.8	0.8	0.8	1.0	1.0	0.9	1.0	0.7	0.8	0.7	0.8	0.6	0.8	0.8	0.8	0.8	0.8
Pacific	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.9	0.9	1.0	1.0	0.9	1.0	0.8	0.9	0.9	0.9	1.0	0.9	1.0	1.0	1.0	0.9
California	0.8	0.9	0.9	0.8	0.9	0.8	0.9	0.9	0.8	0.8	0.8	0.8	0.9	0.9	0.8	0.9	0.8	0.8	0.8	0.8	0.9	0.9	0.9	1.0	1.0	0.9

Figure C-160
Capacity Factor – 2050 – High Gas Price/ No New Transmission Scenario – Coal

Week (weeks 1–26)

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	1.0	0.8	0.9	0.8	0.9	0.8	0.8	0.9	0.9	0.7	0.8	0.8	0.9	0.9	0.9	0.9	1.0	0.9
New York	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	1.0	0.8	0.8	0.9	0.9	0.8	0.8	0.9	1.0	0.9	1.0	1.0	1.0	1.0
Mid-Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0
South Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Florida	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	0.9	0.9	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Regulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.8	0.7	0.8	0.7	1.0	0.7	0.9	0.8	1.0	0.9	1.0	1.0	1.0	1.0	1.0
Texas	1.0	1.0	0.9	0.7	1.0	1.0	0.9	0.9	0.8	0.5	0.8	0.5	0.2	0.4	0.4	0.9	0.4	0.6	0.6	0.9	0.7	1.0	1.0	1.0	1.0	1.0
Mountain North (CO, ID, MT, WY)	N/A - Mountain North contains no nuclear assets																									
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	0.9	1.0	1.0	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.7	0.8	0.9	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.8	0.9	0.9
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	0.9	0.9	1.0	1.0	0.9	0.8	0.8	0.8	0.8	0.8	0.9	0.8	0.9	0.9
California	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.9	0.8	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.9

Week (weeks 27–52)

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.8	0.9	0.9	0.9	0.9	0.8	0.9	0.9	0.9	1.0	0.9	0.9	1.0	1.0	1.0	1.0	1.0
New York	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Mid-Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
South Atlantic	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Florida	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Regulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East North Central (Deregulated)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
East South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West North Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
West South Central	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.9	0.8	1.0	0.9	0.9	1.0	1.0	1.0	1.0
Texas	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	0.9	0.9	0.9	0.8	0.7	0.5	0.8	0.7	0.8	0.9	0.8	0.9	0.8
Mountain North (CO, ID, MT, WY)	N/A - Mountain North contains no nuclear assets																									
Mountain South (AZ, NM, NV, UT)	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	0.9	0.9	0.9	1.0	1.0	1.0	1.0	1.0
Pacific	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
California	0.9	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.9	0.9	1.0	0.9	1.0	1.0	0.9	1.0	0.9	1.0	0.9	0.9	1.0	0.9	1.0	1.0	1.0	1.0

Figure C-161
Capacity Factor – 2050 – High Gas Price/ No New Transmission Scenario – Nuclear

Week (weeks 1–26)

Region	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26
New England	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New York	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid-Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
South Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Florida	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East North Central (Regulated)	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East North Central (Deregulated)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East South Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West North Central	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West South Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Texas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain North (CO, ID, MT, WY)	0.1	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Mountain South (AZ, NM, NV, UT)	0.1	0.1	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Pacific	0.1	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
California	0.2	0.2	0.1	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.1	0.2

Week (weeks 27–52)

Region	27	28	29	30	31	32	33	34	35	36	37	38	39	40	41	42	43	44	45	46	47	48	49	50	51	52
New England	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
New York	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mid-Atlantic	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
South Atlantic	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Florida	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
East North Central (Regulated)	0.1	0.0	0.1	0.1	0.0	0.1	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
East North Central (Deregulated)	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0
East South Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
West North Central	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.0
West South Central	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Texas	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain North (CO, ID, MT, WY)	0.0	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Mountain South (AZ, NM, NV, UT)	0.0	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Pacific	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
California	0.1	0.2	0.2	0.2	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.0	0.2	0.0	0.1	0.0	0.0	0.1	0.0	0.1	0.0	0.1	0.0	0.0	0.0	0.0

Figure C-162
Capacity Factor – 2050 – High Gas Price/ No New Transmission Scenario – Combustion Turbine

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