

Synapse
Energy Economics, Inc.

Meeting Load with a Resource Mix Beyond Business as Usual

A Regional Examination of the Hourly System Operations and Reliability Implications for the United States Electric Power System with Coal Phased Out and High Penetrations of Efficiency and Renewable Generating Resources

April 17, 2013

AUTHORS

Tommy Vitolo, Geoff Keith, Bruce Biewald, Tyler Comings, Ezra Hausman, and Patrick Knight

Prepared for the Civil Society Institute



485 Massachusetts Ave.
Suite 2
Cambridge, MA 02139

617.661.3248
www.synapse-energy.com

Table of Contents

1. EXECUTIVE SUMMARY.....	1
STUDY APPROACH	2
SUMMARY OF FINDINGS	4
2. BACKGROUND.....	5
THE “BEYOND BUSINESS AS USUAL” STUDY.....	5
INTEGRATING VARIABLE-OUTPUT GENERATING RESOURCES	7
<i>Solar</i>	8
<i>Wind</i>	8
<i>Flexible Generation</i>	9
<i>Energy Storage</i>	9
<i>Technologies Facilitating Integration</i>	10
DISPATCH MODEL ANALYSIS	10
<i>Order of Dispatch</i>	11
3. RESULTS BY REGION.....	12
NORTHEAST.....	12
EASTERN MIDWEST.....	17
WESTERN MIDWEST.....	19
SOUTH CENTRAL.....	19
SOUTHEAST.....	20
TEXAS.....	16
CALIFORNIA	13
ARIZONA/NEW MEXICO.....	12
NORTHWEST.....	14
ROCKY MOUNTAINS	15
4. CONCLUSIONS & RECOMMENDATIONS.....	23
5. REFERENCES & DATA SOURCES.....	25
APPENDIX A: SEASONAL RESULTS BY REGION.....	27
APPENDIX B: MODEL DISPATCH ALGORITHM.....	47

1. Executive Summary

A “business as usual” strategy for the U.S. electric power industry, wherein the country continues to rely heavily on coal and other fossil fuels to meet its energy needs, is not tenable if we are to achieve substantial reductions in greenhouse gas emissions over the next several decades. In 2011, Synapse prepared a study for the Civil Society Institute, *Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011* (BBAU 2011), that introduced a “Transition Scenario” in which the United States retires all of its coal plants and a quarter of its nuclear plants by 2050, moving instead toward a power system based on energy efficiency and renewable energy. Synapse’s study showed that this transition scenario, in addition to achieving significant reductions in emissions of CO₂ and other pollutants, ultimately costs society less than a “business as usual” strategy—even without considering the cost of carbon. BBAU 2011 projected that, over 40 years, the Transition Scenario would result in savings of \$83 billion (present value) compared to the business as usual strategy.

As part of this lower-cost and low-emissions strategy, the Transition Scenario included large amounts of renewable energy resources with “variable output,” such as wind and solar. Without the inclusion of these resources, it will be difficult or impossible to reduce electric-sector greenhouse gas emissions to the levels necessary to materially mitigate our contribution to dangerous climate change.

While the need for variable-output resources is well defined, questions have been raised about the impact of large-scale wind and solar integration on electric system reliability.¹ In light of this important concern, Synapse paid careful attention to the amount of wind and solar in each region when designing the Transition Scenario for BBAU 2011, taking steps to ensure that the projected regional resource mixes could respond to all load conditions. These steps included:

- improving the capability of the transmission system to handle large interregional power transfers;
- ensuring that regions with high levels of variable generation also had high levels of flexible generation and capacity;
- adding storage capacity in regions with high levels of wind generation;²
- strengthening the capability and flexibility of electric systems through transmission and distribution investments; and
- developing robust demand-side management resources.

Our current study takes the analysis deeper, in order to explore the extent to which the Transition Scenario’s resource mixes for 2030 and 2050 are capable of meeting projected load for each of the ten studied regions—not just during peak demand conditions, but in every hour of every

¹ Numerous technical studies have demonstrated that it is feasible to add large quantities of variable-output resources to the grid without compromising reliability. Moreover, the studies have shown that the mechanisms for accomplishing this task consist of sensible improvements to grid operation practices, and greater coordination between “control areas” and regions—and that costs to the system would be fairly modest. See, for example, MIT 2012.

² Additional storage was not added in the Northwest region, where the existing dispatchable hydro already serves as a large storage system.

season of the year as consumers require. Using a simplified hourly dispatch model along with empirical load and resource output profiles, we assess the ability of the projected mix in each region to meet load under the varying conditions throughout a day, season, and year. An important limitation of the dispatch model is that it does not include the interregional transfers that were a fundamental part of the resource mix under BBAU 2011, as these have not been defined on an hourly basis. These transfers are an important part of the Transition Scenario for both economic and reliability reasons, and indeed we find that under certain extreme conditions, it is impossible to balance each region in isolation. Nonetheless, our analysis shows that the regional Transition Scenario resource mixes would be capable of meeting load for almost all hours of the year in each region, and that a combination of interregional transfers, local storage, and demand response would be more than adequate to provide a high level of reliability.

This analysis, along with BBAU, is solely based on today's existing technology. We do not expect that the optimal sustainable electricity future for the United States will look exactly like our Transition Scenario, as we anticipate that changes in the technology and economics of carbon-free generation and energy storage will produce options that today would seem unachievable. What we demonstrate in this report is that strategies to address one of the most pressing challenges faced by our species and our planet are already not only achievable, but cost effective. Future developments will only improve this potential—it is up to policymakers to make this potential a reality.

Study Approach

Synapse developed a spreadsheet-based hourly dispatch model to test the capability of the Transition Scenario resource mix in each study region to meet hourly demand in that region.

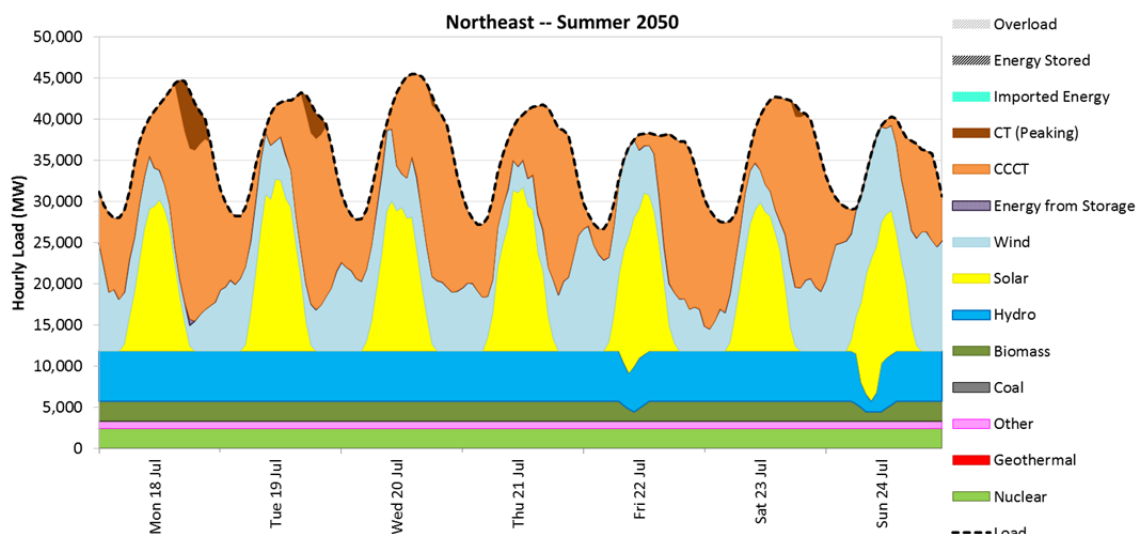
Hourly load data for each region was based on 2010 actual demand, and was adjusted—considering changes in demographics, wealth, and energy efficiency—so that the peak load and annual energy requirements closely matched those in the BBAU 2011 Transition Scenario. Data for these tasks were obtained from FERC 2011, NERC 2012, and U.S. EPA 2011. The generators used in the model came from the BBAU 2011 Transition Scenario.

To model the hourly generation of variable resources, a number of National Renewable Energy Laboratory (NREL) studies and data sets were used. To model hourly wind generation, data sets from NREL's *Eastern Wind Integration and Transmission Study* (EnerNex Corporation 2011) and *Western Wind and Solar Integration Study* (GE Energy 2010) were applied to the power curve of a Vestas V 112 3.0 MW turbine. To model solar output, site specific data from NREL's PVWatts™ calculator was used. Annual hydroelectric capacity factors from the BBAU report were used for the Northeast, Southeast, Eastern Midwest, and Texas regions; monthly hydroelectric capacity factors from the U.S. Bureau of Reclamation were used for the Northwest, California, Arizona/New Mexico, Rocky Mountains, Western Midwest, and South Central regions.

The dispatch model used in this analysis is based on hourly, regional matching of resources to load. At a high level, there are two potential imbalance modes for the model—the available resources could be insufficient to meet projected load, or the output of the resources could exceed projected load, resulting in an unusable surplus. In the vast majority of hours, the model is able to balance resource output exactly with the projected load. Figure 1 shows resource dispatch for a typical, balanced summer week for the Northeast region in 2050. In this case, demand is

being met by a combination of resources, including wind, solar, and natural gas. The level of load is indicated by the dotted line.

Figure 1. Northeast – Modeling Results for One Week in Summer 2050



The imbalance mode in which resources exceed the projected load (to the extent that it results in an unusable surplus) typically occurs in a handful of spring and autumn days with very high wind output and very low demand. In most cases, this would not occur were the model capable of calling on interregional transfers, as is a common practice in physical electric systems and as anticipated in the BBAU report. In addition to such transfers, the dispatching authority would have other tools at its disposal to maintain balance. These include: economic incentives, such as real-time or time-of-use pricing, for shifting the load curve to match resource availability; demand response to *encourage* consumption when surplus energy is available, such as thermal storage in electric water heaters, pre-chilling water for use later in the day, or chemical storage in electric vehicle batteries. As a last resort, dispatchers and operators could angle wind turbine blades to make them less efficient, thereby reducing output.

The tools available for dealing with an unusable surplus ensure that this imbalance mode would not result in reliability or infrastructure impacts; however, angling wind turbine blades to lower output would impact the economics of the wind power facility. Figure 2 below shows a summer week for California in 2050, in which output exceeds load—as well as the ability of storage to capture the surplus—on the last day of the week, a Sunday.

Figure 2. California – Modeling Results for One Week in Summer 2050

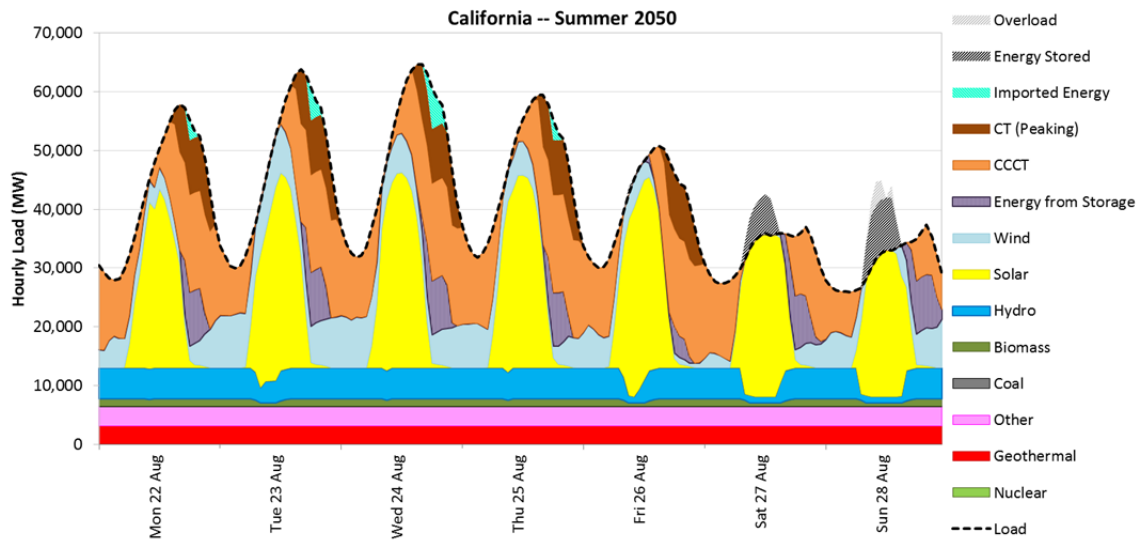


Figure 2 also shows the second imbalance mode, in which local resources are insufficient to meet projected load. This is the least frequent result of our analysis, occurring in circumstances when there is a gap that cannot be met by the Transition Scenario resource mixes for 2030 or 2050. In reality, this circumstance is likely to be averted by importing additional energy from a neighboring region; operators of the future will also likely be able to tap into much more sophisticated demand response techniques, or employ other strategies if necessary to balance resources and load. However, it is informative to see where shortfalls may occur, as a means of identifying issues that could benefit from additional research, and/or regions that may require a resource mix that is substantially different from that which is proposed by BBAU 2011. This discussion may be found in the region-specific discussions in Section 3 of this report.

Summary of Findings

With few exceptions, this study finds that BBAU 2011’s Transition Scenario resource mixes, based entirely on existing technology and operational practices, are capable of balancing projected load in 2030 and 2050 for each region—in nearly every hour of every season of the year. Of course, any viable scenario must be based on much higher levels of reliability, such as a one-outage-in-ten-years standard currently used throughout the United States today. Thus we focus here on any hours with an energy imbalance, either as “unusable surplus” or shortages, to investigate their implications for the feasibility and implementation requirements of the Transition Scenario. This analysis highlights the ways in which interregional cooperation, followed by improvements in technology such as energy storage systems, can provide very high levels of reliability under the Transition Scenario.

In some cases, additional research and/or modifications to the resource mixes posited by BBAU 2011 may be warranted. Discussed in Section 3 of this report, these cases may include the energy shortfalls observed in the southeast and western regions in the summer and winter seasons, and the energy surpluses that occur in Texas and other regions in the shoulder seasons.

As noted above, the BBAU resource mix generally should be seen as an illustrative example, and was never identified as an “optimal” scenario. Integration analysis far beyond that presented here will be an integral part of defining the best combination of resources to provide reliable electric service in a carbon-constrained world. The earlier this sort of in-depth analysis is undertaken, the more options will be available for meeting resource adequacy requirements in a cost-effective way.

This study suggests that it will be feasible to reliably integrate the high levels of zero-carbon energy called for by the Transition Scenario, whether or not this scenario will ultimately provide the most cost effective or elegant nationwide low-carbon energy solution. Achieving this level of integration will likely require incremental improvements in technology and operational practices, including continuation of the current trend toward better interregional coordination. In contrast, the alternative—continuing to rely on increasing combustion of fossil fuels and to bear the growing toll on natural resources and the Earth’s climate presents far more daunting technical, economic, and social challenges to human and environmental welfare.

2. Background

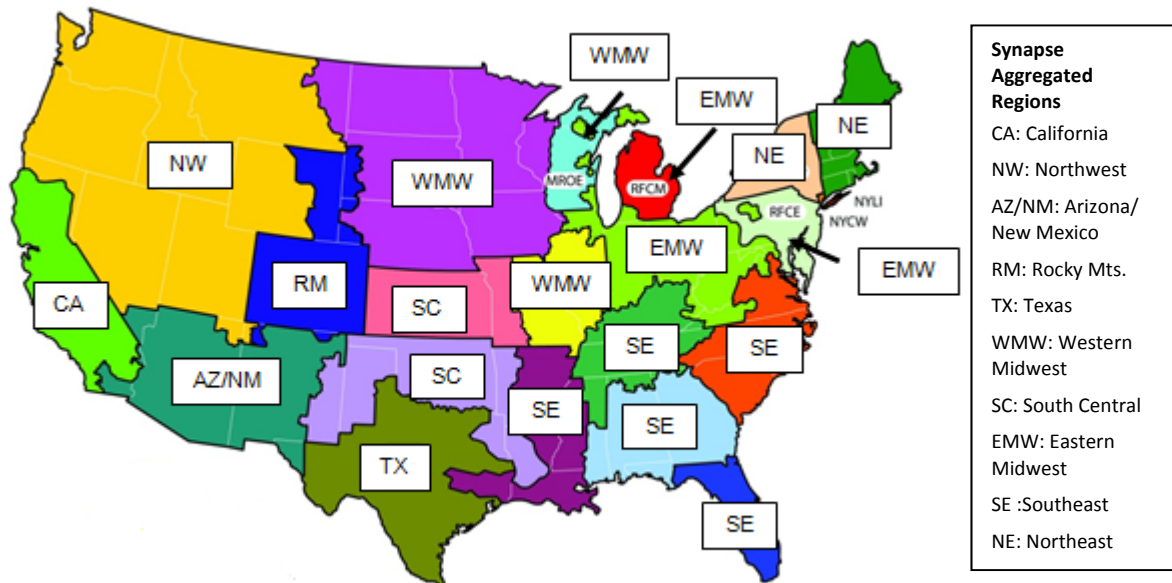
The “Beyond Business as Usual” Study

This study relies heavily on a November 2011 Synapse study for the Civil Society Institute titled *Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011* (BBAU 2011). BBAU 2011 evaluated and compared two scenarios:

- 1) Business as Usual (BAU): Under this scenario, which was based on the U.S. Energy Information Administration’s Annual Energy Outlook (AEO) 2011 modeling work, the country continues to rely on fossil and nuclear generation to meet its energy needs, and electric-sector carbon dioxide (CO₂) emissions continue to increase.
- 2) Transition Scenario: Under this scenario, the country moves toward a power system based on efficiency and renewable energy, and CO₂ emissions are reduced substantially. In the Transition Scenario, all U.S. coal-fired power plants are retired, along with nearly a quarter of the nation’s nuclear fleet, by 2050.

For BBAU 2011, Synapse estimated the net costs and benefits of the Transition Scenario relative to BAU using a spreadsheet model that accounted for generating capacity, energy, fuel use, costs, emissions, and water use. Synapse performed the analysis on a regional basis, with the country divided into ten regions aggregated from the 22 regions used in AEO 2011 as shown in Figure 3. For each region, Synapse ensured that there was sufficient generating capacity in both the BAU and Transition scenarios, and that there was a generally reasonable mix of energy sources in each region from the perspective of power system operation.

Figure 3. Aggregating the EIA Regions for BBAU 2011, and the Current Study



The analysis for the current study is focused on these same ten regions.

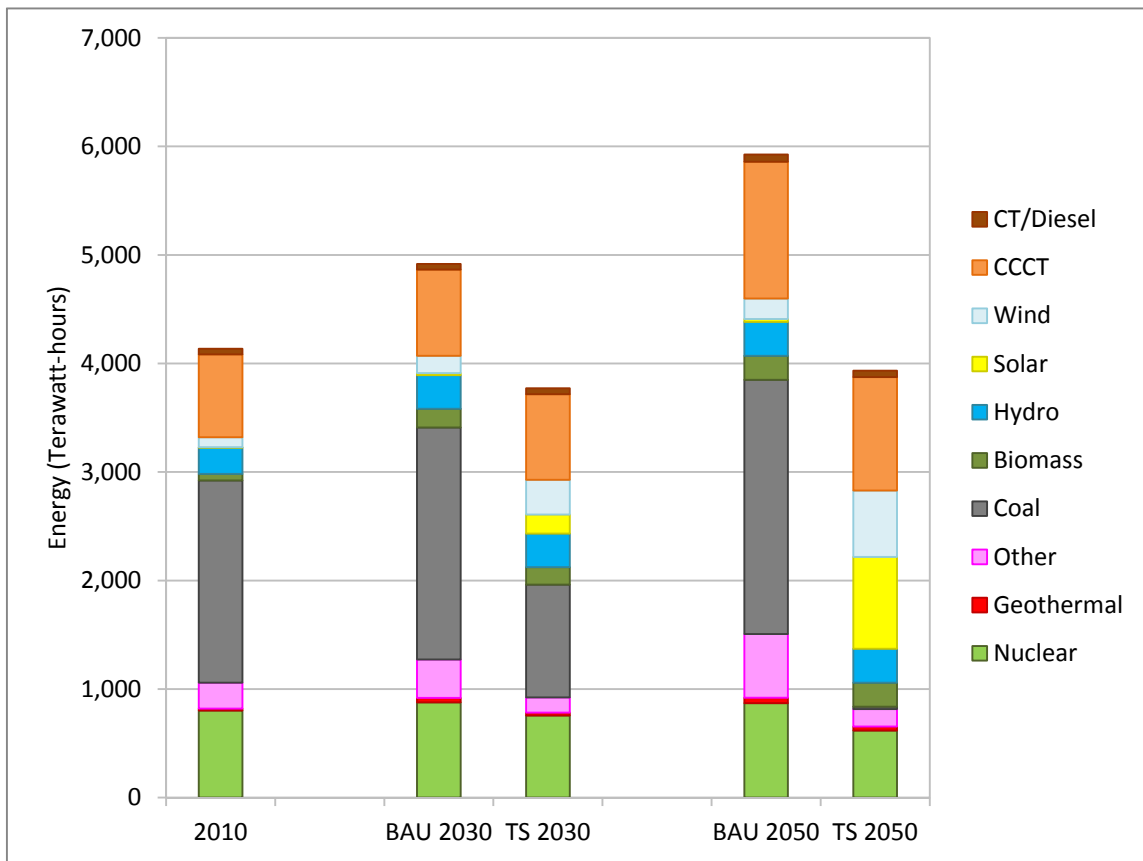
For most of our technology cost and performance assumptions, we relied on the AEO 2011 data (U.S. EIA 2011). If judged to be more accurate than AEO 2011, other data sources were used for some technologies.³

BBAU 2011 found that the Transition Scenario was significantly less expensive than the BAU Scenario—saving a present value of \$83 billion over 40 years. This finding was particularly striking, given that the BAU Scenario included no carbon costs or carbon reductions. If the cost of carbon reductions (or the societal cost of continued emissions) were included in the BAU Scenario, the savings provided by the Transition Scenario would have been far higher.

Figure 4 illustrates the resource mix for the BAU and Transition scenarios for 2030 and 2050.

³ See the appendices of the BBAU 2011 report for a full list of data sources used in that study. The report is available at <http://www.synapse-energy.com/Downloads/SynapseReport.2011-11.CSI.BBAU-2011.11-037.pdf>.

Figure 4. Continental United States Resource Mix for BAU and Transition Scenarios in 2030 and 2050



Synapse included a large amount of zero carbon, variable output resources—i.e., wind and solar—in the Transition Scenario. In designing this scenario, Synapse paid careful attention to the wind and solar energy potential in each region, and attempted to ensure that the projected resource mixes and interregional transfers were likely to be capable of meeting all load conditions. These steps included: ensuring that regions with high levels of variable generation also had high levels of flexible generation and capacity; adding storage capacity in regions with high levels of wind generation; strengthening the capability and flexibility of electric systems through transmission investments; and including the cost of implementing robust demand response programs. We also noted that trends in system operation—such as consolidation of balancing areas, and increased information sharing—were likely to facilitate the integration of variable resources under either scenario.

Our present study takes the analysis deeper to explore the extent to which the Transition Scenario resource mixes for 2030 and 2050 meet projected hourly load for each of the ten regions.

Integrating Variable-Output Generating Resources

Historically, grid operators have responded to real-time changes in demand by virtually instantaneous control of generating resources to maintain frequency and voltage, and to balance electricity supply and demand. Outside of scheduled maintenance outages and unforeseen

events, such as the failure of a generating plant or the loss of a transmission line, operators have assumed that generators are available and reliable, and that demand is fairly predictable—especially if weather conditions are known. Integrating high levels of variable-output resources into the electric grid will require a significant shift in perspective from grid operators (DOE 2008).

While variable-output generators cannot be directly controlled by the operator, they provide significant benefits including increased price stability and contributions to meeting peak demand (APS 2010). By reducing the usage of fossil fuels to produce electricity, solar and wind resources also provide significant benefits in terms of reducing an electric system's greenhouse gasses, air pollutants, water usage, and solid waste.

Solar

The output of solar resources is dependent on the angle of the sun and the presence of clouds. Based on current scientific knowledge, we are able to forecast the angle of the sun with complete accuracy for centuries into the future. Using satellites and other meteorological tools, we can forecast the presence of clouds at a given location for several hours into the future.

Solar thermal resources—which use mirrors to focus sunlight to heat steam for a turbine—cannot operate without direct sunlight; however, they are often able to store heat and thereby continue generating electricity for several hours after dusk (DOE 2008). Solar photovoltaic (PV) resources, on the other hand, do not require direct sunlight to generate electricity, but offer no storage ability. They can be mounted in a fixed position, or can change their angle throughout the day to be optimally positioned with respect to the angle of the sun. Intermittent clouds introduce unpredictability for PV facilities, since they produce energy at lower levels if direct sunlight is not available. PV resources do not produce energy after dusk. Despite these constraints, both types of solar resources are beneficial to the electrical system, since optimal operating conditions with direct sunlight often coincide with summer peak demand (MIT 2012).

Wind

The output of wind resources is often characterized as being very unpredictable. However, while the output of an individual wind turbine at any point in time is extremely difficult to predict, the output of a group of turbines becomes more predictable as the number of turbines and their geographic diversity increase. Individual turbines are sensitive to changes in wind strength which can be localized and short-lived, or broad-scaled and persistent. In contrast, large groups of turbines, such as wind farms, are less subject to local and short-lived variations, and regions with geographically diverse wind resources are even more robust (DOE 2011). Wind resources can also exhibit predictable seasonal and diurnal variations; turbines are typically more likely to run in the early morning and in the winter. Even if the wind is not coincident with peak demand, large-scale patterns provide predictability for balancing purposes (MIT 2012). Additionally, new wind forecasting tools are being developed to help system operators prepare for changes in wind production. The Electric Reliability Council of Texas (ERCOT), working with AWS Truepower and other third parties, has implemented a tool to provide useful 6-hour, 4-hour, and 2-hour-ahead wind power forecasts.⁴

⁴ See ERCOT's 2010 press release: http://www.ercot.com/news/press_releases/show/326

Flexible Generation

Today, unpredictable variations in load and in the output of variable-output resources are accommodated through the use of high flexibility resources including storage hydropower and flexible mid-merit and peaking gas units. The Transition Scenario was designed to include sufficient quantities of these resources to meet additional variable output generation. These resource types include:

- *Storage Hydro* - Hydro facilities with reservoirs can be quickly ramped up or down in response to load, which is useful for complementing variable renewable generation (Denholm 2010). Today many of these facilities use their storage capability to generate as much electricity as physically possible during high-load and high-cost daytime hours and little or none overnight.
- *Combustion Turbine (CT) Peaking Units* - Gas-fired combustion turbines can be ramped up or down quickly; however, they are also the least efficient and typically the most expensive generators to run (MIT 2012). Peaking units typically have a very short lead time for construction, and can be installed quickly to help meet expected growth in load *or* in the need for flexible generation.
- *Combined-Cycle Combustion Turbine (CCCT) Gas Plants* - Gas-fired combined cycle plants provide a valuable mix of high efficiency and operational flexibility to complement variable resources (MIT 2012). They can ramp up and down quickly, and are more efficient and cost-effective to run than CT (peaking) units, as they require less natural gas per MW of output. However, they are more expensive to build and require longer construction lead-time than CTs.

Energy Storage

Energy Storage exists today in the forms of pumped hydropower, compressed air storage, flywheels, and batteries. Thermal energy storage in buildings and industrial settings is also used today. Storage provides the ability to both absorb electricity during hours of surplus and to dispatch it as a generator at a later time. Energy storage will always involve some level of losses—for example, it takes more energy to fill a pumped hydro storage reservoir than can be recovered by releasing the water. Today's advanced storage technologies, such as batteries and flywheels, are relatively expensive and limited in scale, and have thus been applied mostly for specialty applications. However, lower-cost energy storage is an area of very active research and development, including efforts to improve batteries, develop hydrogen production and storage, and implement end-use storage such as thermal storage in buildings, electric water heaters that can respond to system operator controls, and plug-in electric vehicles. Energy storage will almost certainly play an important role in any energy future with higher levels of renewable resources, because storage effectively converts intermittent energy generation to highly flexible dispatchable generation. This study assumed that future storage would have the same cost and efficiency structure as current storage; however, technological advancements will only improve the cost and performance of electrical storage over time.

Technologies Facilitating Integration

All of the aforementioned constraints and operating characteristics must be taken into account when integrating generating resources into the grid, in order to maintain the balance of generation of load.

High levels of variable-output generation (wind and solar) add another layer of complexity to the existing challenges of balancing generation and load in real time while ensuring high levels of reliability. Fortunately, a number of tools are available or under development to help grid operators more easily capture the benefits of variable generation while maintaining a reliable electric system. These tools include electricity and thermal energy storage (described above), extended use of demand response resources, and smart grid applications that can be used for load and frequency balancing (APS 2010; Denholm 2010; MIT 2012). The wider use of electric vehicles will also provide an opportunity for storage and load control to the grid (MIT 2012). As discussed above, geographic diversity and diversity of resource types over larger regions will naturally smooth out some of the variability and unpredictability associated with variable-output resources. Finally, improved approaches to using existing, flexible resources such as storage hydro and gas, combined with better forecasting for variable resource output and real-time control, will substantially enhance the ability to accommodate high levels of variable-output renewable energy (Lew et al. 2010).

Dispatch Model Analysis

The purpose of this study was to determine whether and in how many hours of the year the BBAU 2011 Transition Scenario resource mixes for 2030 and 2050 resulted in insufficient electricity available to serve load, or an unusable surplus of electricity.

To perform this analysis, Synapse built a simplified hourly dispatch model based on hourly, regional matching of resources to load. Inter-hourly constraints such as generator ramping limitations are not considered, nor are local transmission constraints. The model does not explicitly model imports and exports between regions. Finally, the model does not consider the need for reserves or any other ancillary service. While a more comprehensive, in-depth dispatch modeling study might accommodate these dynamics and constraints better, we believe the analytical benefits would be illusory; they would be based on limitations and operational practices of today that are not likely to be characteristic of the future study years. On the other hand, the model does not model demand response as a resource. When dispatched, demand response resources allow the systems operator to shift the load curve in order to mitigate or eliminate energy imbalances. This, along with the exclusion of interregional transfers of power, renders the model relatively conservative for this analysis.

Hourly load data for each region was based on 2010 actual demand, and was adjusted—considering changes in demographics, wealth, and energy efficiency—so that the peak load and annual energy requirements closely matched those in the BBAU 2011 Transition Scenario. Data for these tasks were obtained from FERC 2011, NERC 2012, and U.S. EPA 2011. The generators used in the model came from the BBAU 2011 Transition Scenario. To model the hourly generation of variable resources, a number of National Renewable Energy Laboratory (NREL) studies and data sets were used (NREL PVWatts 2012, GE Energy 2010, and EnerNex Corporation 2011).

Order of Dispatch

For purposes of dispatching units in order of economic merit to meet load, generating resources were divided into four major dispatch categories: low-flexibility dispatchable generation (such as baseload nuclear and coal), variable resources, high-flexibility dispatchable generation, and storage.

The model simulates unit commitment⁵ by looking ahead to the upcoming week (168 hours) to determine if coal or biomass resources would be needed to meet demand, or if they would be called on in the ordered dispatch frequently enough to justify being made available for the week. The model then calculates hourly load net of variable resource output to determine how much energy from conventional resources is required, if any. If variable resource output is too high relative to load, the model attempts to absorb the excess energy into available storage. If more energy is required, the model tries to meet load using the following resource ordering, using all available capacity in one before moving on to the next: storage hydro; coal (if available); biomass (if available); energy stored from any surplus in previous hours; CCCT gas, and then peaking gas. If all of those resources, when dispatched, still fail to meet load, any available emergency storage is called upon. The model assumes that, in an actual scenario like this, system operators would have anticipated the need for energy reserves,⁶ and would have prepared by storing surplus energy in the prior time periods.⁷ If the emergency storage is not sufficient to meet load, then a shortfall occurs.

Under realistic operating conditions, it is likely that techniques to shift load such as time-of-use pricing and thermal and chemical storage demand response would be employed, thereby reducing the extent of surpluses and shortages. Any shortfall would be met by importing energy from a neighboring region (as is commonly done for economic and reliability reasons today) or by the use of additional demand response. These resources are not available to the dispatch logic in our model, rendering the dispatch analysis conservative relative to the actual challenged likely to be faced by system operators.

A detailed description of the rules by which the model dispatches resources is provided in Appendix B.

⁵ “Unit commitment” is the process of determining which long-lead resources will be made available for use during the commitment period, based on anticipated load conditions. In this analysis, coal and biomass resources are only “committed” for weeks in which regional load could not be met in their absence, or if they would be used frequently for economic reasons.

⁶ System operators anticipate the need for reserves based on a thorough understanding of the load curve, weather forecasts, and other factors. Taking these factors into account, dispatchers can anticipate the need for reserves, and “fill up” necessary storage, 24 to 48 hours in advance.

⁷ This use of storage may be likened to the logic used in hybrid-electric vehicles, which optimize the use of battery storage to both have capacity available to store energy from regenerative braking, and to ensure that energy is available when needed to provide extra torque to the drive train.

3. Results by Region

As described above, this study divides the contiguous United States into ten regions to conduct the analysis (see Figure 3). Here we summarize the results of the analysis for each of these regions, for the study years 2030 and 2050. During most hours in every region, the dispatch logic produces a balanced system using Transition Scenario resources. All of these scenarios should ultimately be analyzed using probabilistic electric system reliability modeling. Thus the figures and discussion in this section focus on hours with energy imbalance, either as “unusable surplus” or shortages, to investigate their implications for the feasibility and implementation requirements of the Transition Scenario.

Arizona/New Mexico

2030

No energy shortages occur in 2030. CT units are dispatched for a significant number of hours in the summer, and fewer hours in the fall, to help meet load.

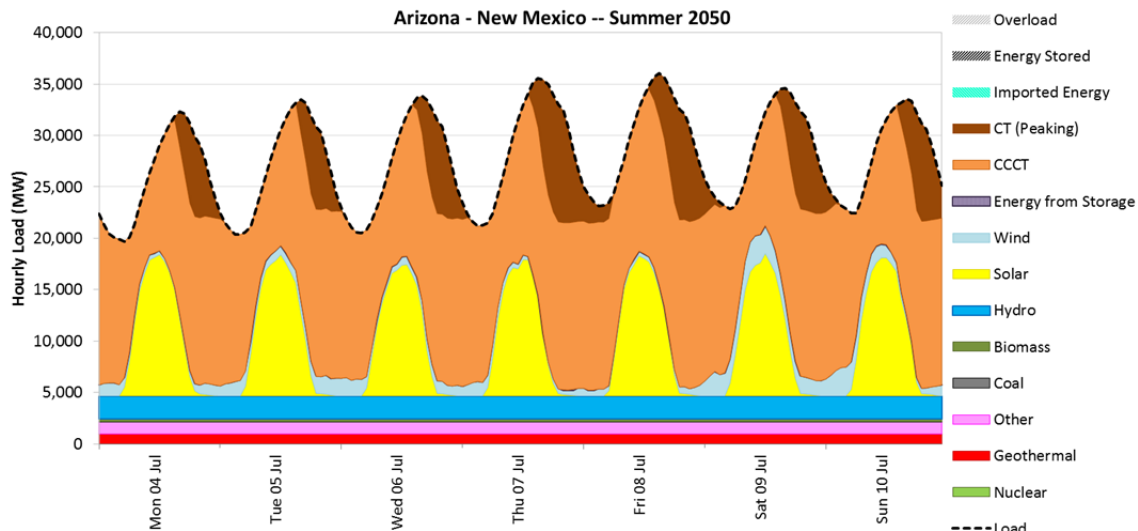
No surpluses occur in any of the seasons, in part due to the region’s flexible hydro resources.

2050

There are a small number of hours in the summer in which the available resources were insufficient to meet load, and imports would be required from a neighboring region. The twelve hours span seven days, and never exceed 1.2 GW.

As shown in Figure 5, below, CT units are dispatched for a large number of hours in the summer, especially in the late afternoon and evening, to meet load.

Figure 5. Arizona/New Mexico – Modeling Results for a Summer Week in 2050



Surpluses of energy, beyond what can be captured by available storage, occur in a few hours in spring and winter, peaking at around 2 GW. Usable surpluses of energy, which are absorbed by storage to be dispatched later, occur throughout the year, less than once per week.

These results suggest that the Arizona/New Mexico region may benefit from additional storage or import/export capacity, and would also benefit from the construction of additional solar or wind to help reduce CC usage year-round and CT usage in the summer. The region would also derive substantial benefit from more solar thermal resources than BBAU calls for, thereby helping meet the late afternoon energy gap, particularly in the summer months.

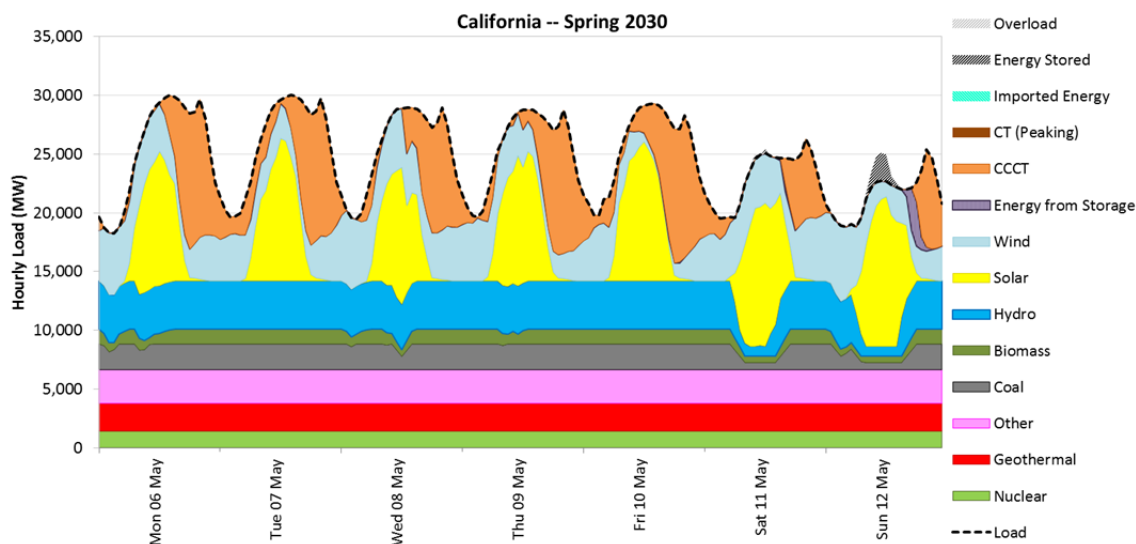
California

2030

There are a few peak days in the summer, and three consecutive days the fall, in which the available resources were insufficient to meet load, and imports would be required from a neighboring region. On the hours of insufficient California generation on these sixteen days, the three other western regions—the Northwest, Rocky Mountains, and Arizona/New Mexico—all had power available for California to import. This highlights the importance of intraregional planning, dispatch, and transmission.

CT units are dispatched for a large number of hours in the summer and fall, and a few hours in the spring and winter, to meet load.

Figure 6. California – Modeling Results for a Spring Week in 2030



Surpluses of energy, beyond what can be captured by available storage, occur in a small number of hours in 2030. Usable surpluses of energy, which are absorbed by storage to be dispatched later, occur frequently on weekends, particularly in spring and fall. A spring week with a “usable surplus” is shown in Figure 6, above.

2050

There are several hours in the summer and early fall in which the available resources were insufficient to meet load. These shortages occurred in late afternoon and evening hours during periods of high demand and low wind. Unlike in 2030, the other western regions do not have substantial surplus in these hours, suggesting that California would need to rely on additional

strategies—above and beyond importing energy—to meet load in 2050. Because Texas did have surplus renewable energy during those hours, one approach could be to increase the amount of DC transmission capacity from Texas to the Western Interconnect’s load centers.

CT units are dispatched for a significant number of hours in the summer, fall, and winter to meet load.

Surpluses of energy, beyond what can be captured by available storage, occur in a few hours in 2050. These “unusable surpluses” occur on approximately 50 days throughout the year, and peak at about 10 GW in wintertime. Usable surpluses of energy, which are absorbed by storage to be dispatched later, occur multiple times each week during most weeks of the year, and at least once each week.

These results suggest that California may want to construct more storage and/or dispatchable generation, implement demand side management programs to shift demand from after sundown to late afternoon/evening peaks in summer and fall, and/or construct more solar thermal generation (which, when built with a storage component, continues to produce energy after dusk).

Northwest

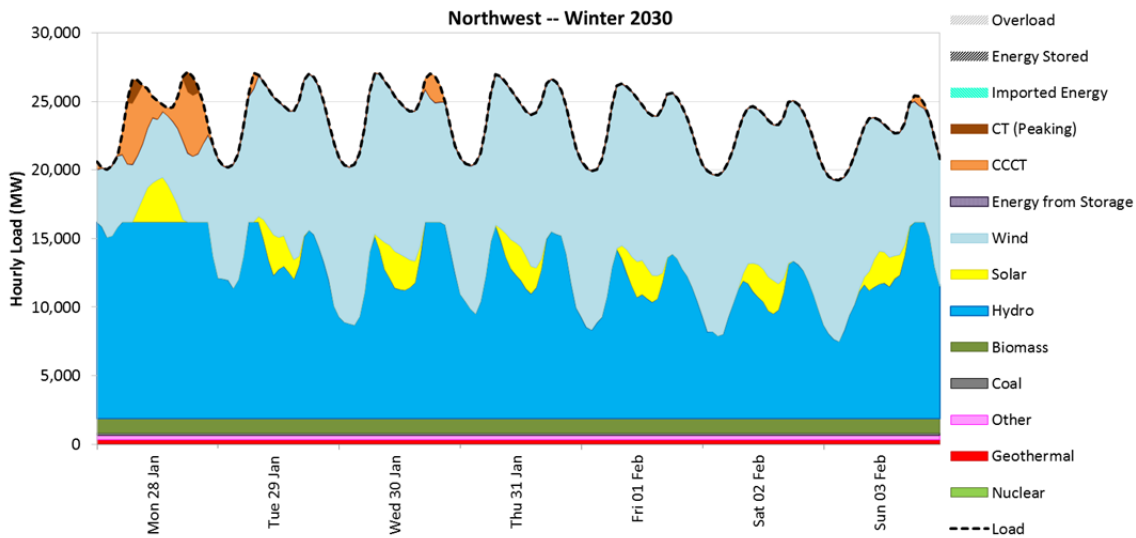
2030

There is one instance in the summer, and a few hours in the winter, in which the available resources were insufficient to meet load. In all of these hours, other western regions had generation available to export to the Northwest.

CT units are dispatched in July and December to help meet load. Natural gas usage is rare in the spring season, due to high production from hydroelectric facilities. As shown in Figure 7, renewable resource generation is so substantial that coal units are often not dispatched at all. In fact, coal units are not dispatched in over half of the weeks of the year.

Surpluses are extremely rare and on the order of 1 GW, in part due to the extent of the region’s flexible hydro resources.

Figure 7. Northwest – Modeling Results for a Winter Week in 2030



2050

There are a large number of hours in the fall and winter in which the available resources were insufficient to meet load; shortages peaked at about 10 GW, although most were under 1 GW. While surplus was available from other western regions for some of these hours, the frequency and magnitude (as large as 10 GW) of the fall/winter shortages suggests that more generation may be needed in the Northwest region.

CT units are dispatched for a significant number of hours in autumn and winter to meet load. No fossil-fuel generators are dispatched from late spring through early September.

Surpluses of energy, the majority of which are captured by available storage, occur as often as a few times per week in 2050. The “unusable surpluses” occur much less frequently, typically in the first half of the year when renewable generation capacity factors high. The surplus energy peaks at about 7 GW on a weekend day in the spring.

These results suggest that the BBAU resource mix would need to be modified for the Northwest in 2050. The region may benefit from more generation and, if that generation is variable, more storage. These results also point to the need for additional research and analysis in the Northwest. The difficulty in modeling hydro is exacerbated in this region, where hydro can make up over 50% of a week’s energy generation. In order to get a clearer sense of the ability of the BBAU resource mix to meet hourly demands in the Northwest, an essential step would be to apply a model that includes more detailed information about each of the region’s hydro generation facilities

Rocky Mountains

2030

No energy shortages occur in 2030. CT units are dispatched for a significant number of hours in the summer to help meet load.

Surpluses of energy, beyond what can be captured by available storage, do not occur in 2030. Usable surpluses of energy, which are absorbed by storage to be dispatched later, occur rarely and in very small amounts, the result of an increase in wind or solar generation exceeding the ability for coal and biomass fired generators to scale back their generation.

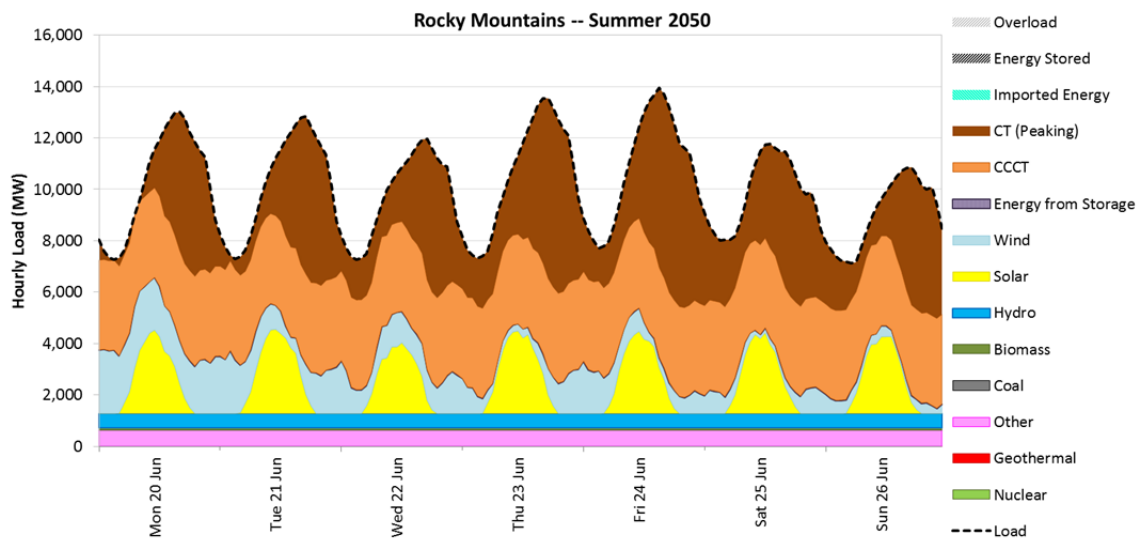
2050

No energy shortages occur in 2050. CT units are dispatched for a significant number of hours in every season to help meet load. Figure 8, below, shows significant CT deployment in a summer week.

Surpluses of energy do not occur in 2050.

The region’s frequent CT usage in 2050, and the nonexistence of surplus energy hours, demonstrate that there are likely lower-cost and less carbon intense methods to help meet load, including deploying more wind and solar resources, utilizing imports from other western regions when they are flush with renewable energy, or building more combined cycle (CC) generation units, which consume less natural gas per megawatt than the CT units being deployed.

Figure 8. Rocky Mountains – Modeling Results for a Summer Week in 2050



Texas

2030

No energy shortages occur in 2030. CT units are dispatched for a few hours a day, for about a dozen days, to help meet summer load.

Surpluses of energy, beyond what can be captured by available storage, occur in a large number of hours in 2030, and no storage has been specified for the region. These “unusable surpluses” occur in spring, fall, and winter, and peak at about 10 GW.

These results suggest the need for Texas to employ some combination of additional storage facilities, load shifting techniques, an increase in DC transmission lines to allow for exporting to Eastern or Western Interconnects (particularly the Southeast), and curtailment of wind production.

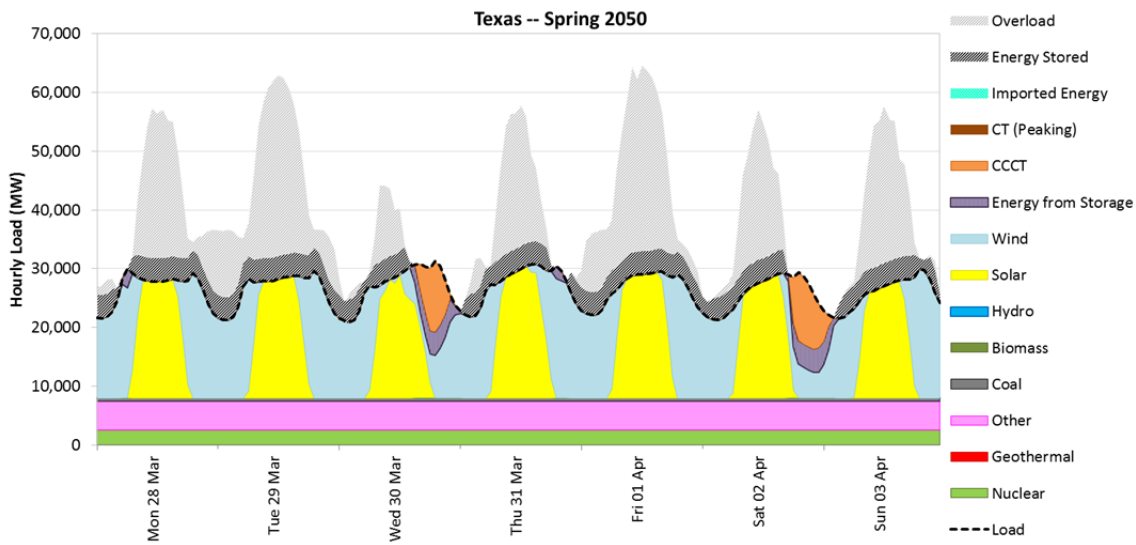
2050

No energy shortages occur in 2050. CT units are dispatched for a few hours in summer to help meet load.

Surpluses of energy, beyond what can be captured by available storage, occur in over 3,000 hours in 2050. These surpluses occur in every season, often at substantial levels, and peak at about 31 GW in spring (see

Figure 9, below). Texas is positioned to export energy both to the Southeast and Southwest, two regions where the majority of the hours see the burning of fossil fuels in 2050, although perhaps more transmission will be needed to take full advantage of Texas' tremendous renewable energy generation potential.

Figure 9. Texas – Modeling Results for a Spring Week in 2050



These results make clear that Texas would benefit from changes to the BBAU resource mix for 2050. On an annual or even a weekly basis, Texas is able to meet its energy needs without coal or gas generation. However, without a substantial increase in storage, load shifting ability, or increased import/export capabilities, the region will have to curtail substantial amounts of renewable generation in many hours, and unnecessarily rely on fossil fuel generation in others.

Eastern Midwest

2030

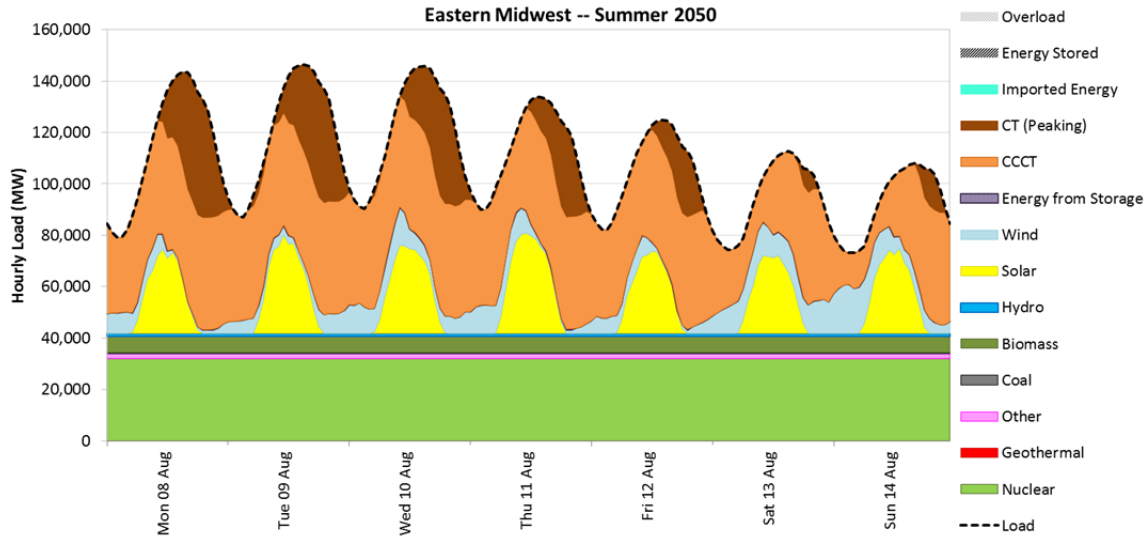
No energy shortages occur in 2030. CT (peaking) units are dispatched for a small number of hours in the winter, and on several weekday afternoons in the summer, to help meet load.

No surpluses occur in any of the seasons.

2050

No energy shortages occur in 2050. CT units are dispatched in a similar pattern to 2030, due to lower summertime wind capacity factors. As seen in Figure 10, the Eastern Midwest frequently burns natural gas, even at the height of solar generation. This suggests that the region could comfortably build even more wind and solar generation, or could frequently import the surplus generation common in the Northeast and Western Midwest regions.

Figure 10. Eastern Midwest – Modeling Results for One Week in Summer 2050



Surpluses of energy, beyond what can be captured by available storage, occur in a few hours in 2050. These “unusable surpluses” occur primarily during the mid-morning hours in spring and fall, and peak at 20 GW. Some of these surpluses can be exported, but occasionally they occur during hours when many or all of the regions on the Eastern Interconnect also have surplus. During that handful of hours, other methods of handling surplus energy must be employed.

Usable surpluses of energy, which are captured by storage to be dispatched later, occur in all seasons, including rare occasions in winter and summer.

Northeast

2030

No energy shortages occur in 2030. In some summer days, CT (peaking) units and stored energy are both dispatched to meet load in late afternoon.

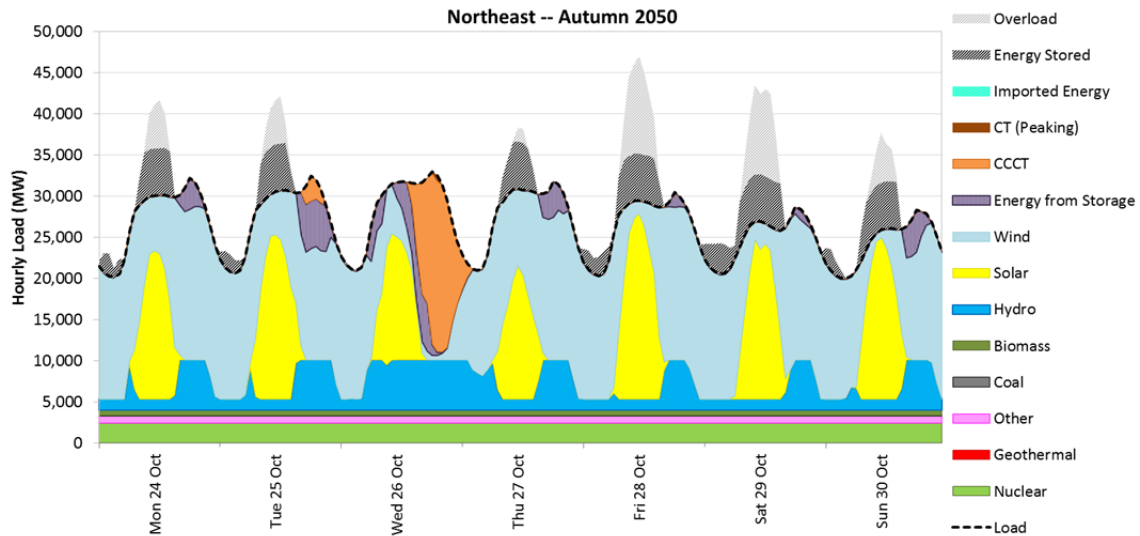
A surplus of energy, beyond what can be captured by available storage, occurs during spring and fall during late hours. Usable surpluses of energy, which are absorbed by storage to be dispatched the following day, occur occasionally at 2 a.m. in the shoulder seasons. This is due to low loads and ample wind. Usable surpluses also occur in the winter. The summer sees very little surplus.

2050

No energy shortages occur in 2050. CT (peaking) units are dispatched on a few summer days to help meet load.

Surpluses of energy, beyond what can be captured by available storage, occur frequently in 2050. These “unusable surpluses” occur primarily during the daytime hours in spring and fall, and peak at around 10 GW, as seen in Figure 11, below. Usable surpluses of energy, which are absorbed by storage to be dispatched later, occur in all seasons, including a few winter and summer days.

Figure 11. Northeast – A Week with Surplus Energy Output - Autumn 2050



It is worth noting that, in 2050, the neighboring Eastern Midwest (EMW) region is dispatching natural gas generation during most of the hours in which the Northeast is producing excess energy, suggesting the opportunity to export the surplus and thereby decrease both cost and fossil fuel consumption in EMW. However, there are multiple days in the summer when exporting the surplus energy would be impossible (i.e., surrounding regions were also generating a surplus); for these situations, the Northeast would benefit from more storage than BBAU 2011 proposes. This might include increased traditional storage—such as pumped hydro, batteries, or compressed air—or thermal storage, through which load is shifted to strategically make use of the surplus energy when it is occurring. Without sufficient export or storage capacity, the grid operator might be forced to curtail some of the variable-output renewables, likely wind.

South Central

2030

No energy shortages occur in 2030. CT units are dispatched for a few hours in the winter, and for a significant number of hours in the summer, to help meet load.

No surpluses occur in any of the seasons.

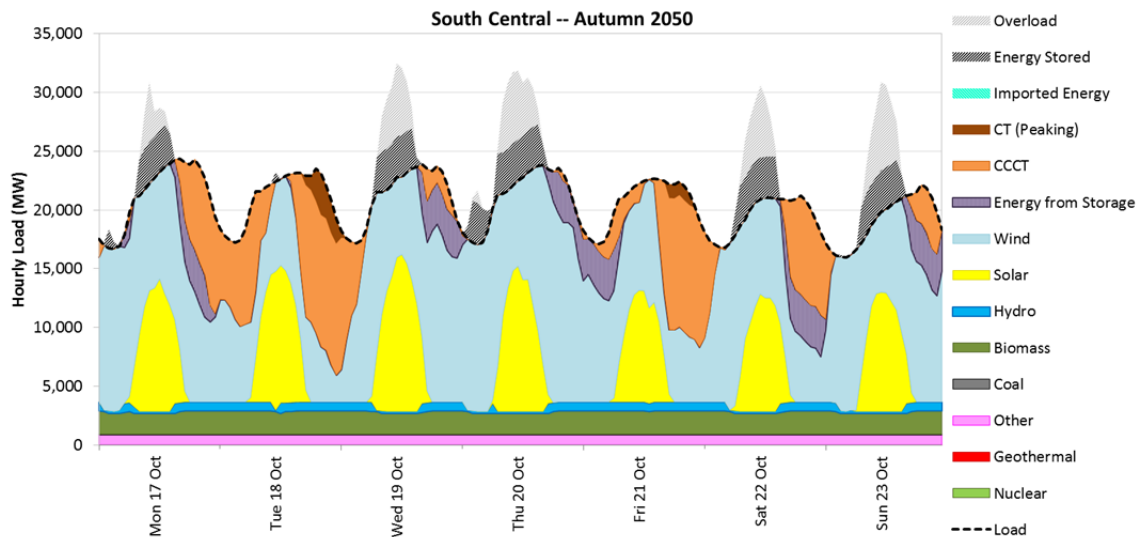
2050

No energy shortages occur in 2050. CT units are dispatched a substantial amount in both the summer and winter months to meet load.

Surpluses of energy, beyond what can be captured by available storage, occur for over 1,000 hours in 2050. They occur in spring and fall, and peak at about 9 GW. Usable surpluses of energy, which are absorbed by storage to be dispatched later, occur in all seasons, including a few hours in winter and summer. During many of the hours of surplus, the neighboring Southeast region is burning fuel to generate electricity; there would be an opportunity to export renewable energy to the Southeast during those hours.

These results suggest that, similar to the Northeast and the Western Midwest, the South Central region might benefit from more storage than BBAU 2011 proposes, as well as load-shifting and export capacity to Eastern Midwest and the Southeast regions.

Figure 12. South Central – Modeling Results for an Autumn Week in 2050



Southeast

2030

No energy shortages occur in 2030. CT units are dispatched for a significant number of hours in the winter and summer to help meet load.

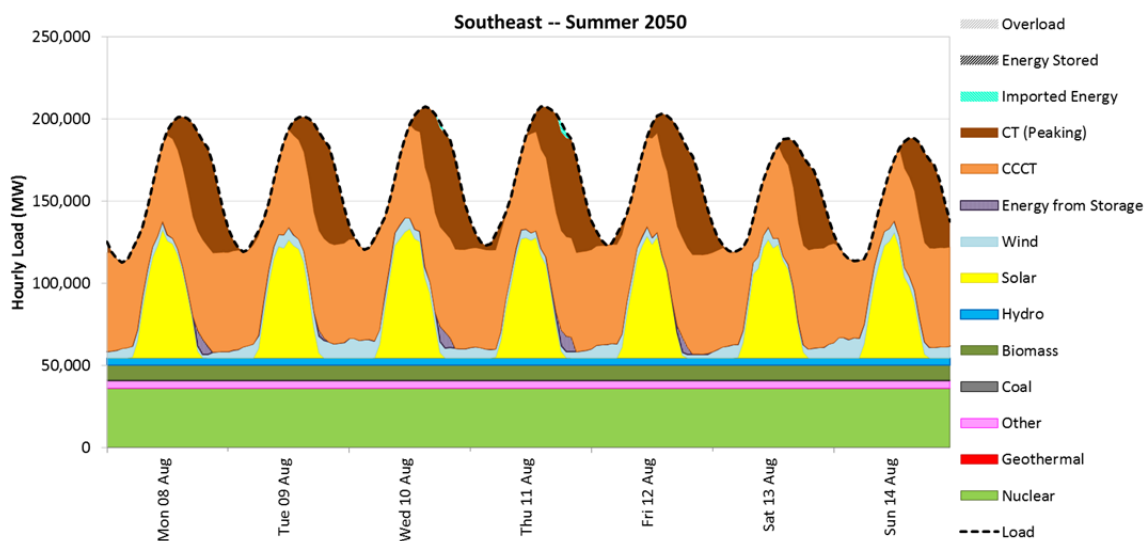
No surpluses occur in any of the seasons.

2050

As illustrated in Figure 13, there are a few hours in the summer and winter in which the available resources were insufficient to meet load, and imports would be required from a neighboring region. The shortages, though infrequent and small in magnitude, demonstrate that more resource sharing and intraregional planning must occur in the future. During the hours when the Southeast

is unable to meet its own load, the Eastern Midwest, Western Midwest, South Central, and Texas regions had sufficiently large surplus capacity to allow the Southeast to meet load with the help of imports. On multiple summer and winter days, CT units, as well as emergency storage, are dispatched.

Figure 13. Southeast – Modeling Results for a Summer Week in 2050



Surpluses of energy, beyond what can be captured by available storage, occur in 2050 due to simultaneous high output from solar and wind resources at mid-day. These “unusable surpluses” occur primarily in spring and fall, peaking at about 20 GW in the spring and 10 GW in the fall. During some of those hours it would be possible to export the surplus energy to other regions. Usable surpluses of energy, which are absorbed by storage to be dispatched later, occur in all seasons.

These results suggest that the Southeast region may benefit from the construction of more storage and/or dispatchable generation above and beyond the BBAU 2050 resource allocation, and/or the implementation of demand side management programs to shift tens of gigawatts of demand from after sundown to mid-day. An alternative is to sign import contracts to ensure that energy can be brought in from the South Central, Western Midwest, Eastern Midwest, or Texas regions during winter and summer weekdays in the late-afternoon hours.

Western Midwest

2030

No energy shortages occur in 2030. Some amount of fossil fuel is burned to meet load in nearly every hour of the shoulder seasons. CT units are dispatched for a few hours in the winter and for a substantial number of summer hours in order to meet load.

No surpluses occur in any of the seasons.

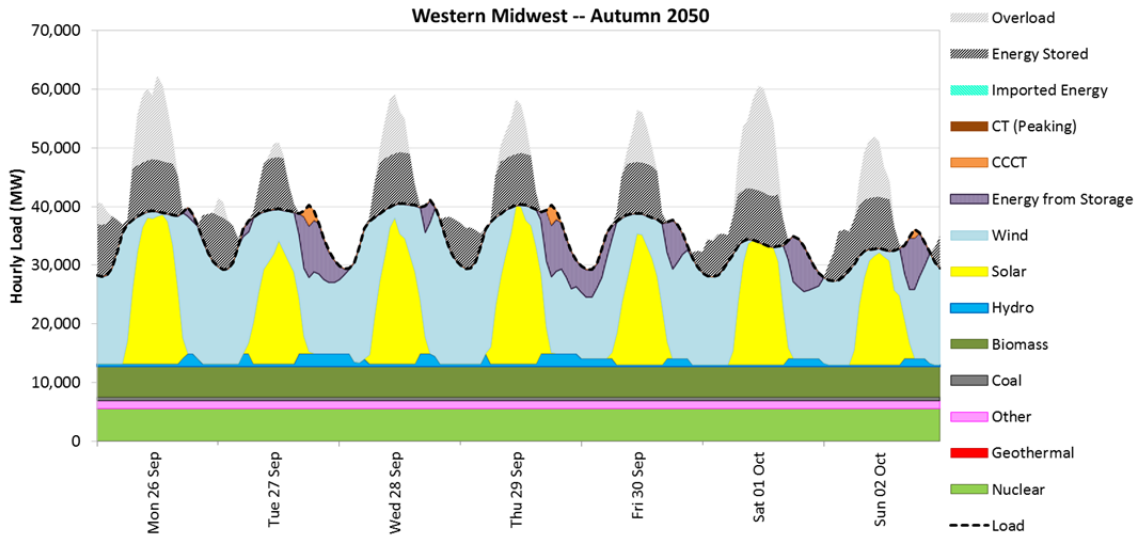
2050

No energy shortages occur in 2050. CT units are dispatched on many weekdays in both the summer and winter months to meet load.

Surpluses of energy, beyond what can be captured by available storage, occur primarily during peak periods in spring and autumn (see Figure 14, below), occur in nearly 20% of the year's hours, and peak at about 20 GW. Exporting to the Eastern Midwest and Southeast regions are possible during most hours of excess energy, as the Eastern Midwest and Southeast regions are often burning natural gas to create electricity during those hours. Usable surpluses of energy, which are absorbed by storage to be dispatched later, occur in all seasons.

These results suggest that, similar to the Northeast, the Western Midwest region might benefit from more storage than BBAU 2011 proposes, as well as load-shifting and export capacity.

Figure 14. Western Midwest – Modeling Results for One Week in Autumn 2050



4. Conclusions & Recommendations

With few exceptions, this study finds that BBAU 2011’s Transition Scenario resource mixes, based entirely on existing technology and operational practices, are capable of balancing projected load in 2030 and 2050 for each region—in nearly every hour of every season of the year. Of course, any viable scenario must undergo an extensive suite of analysis, including probabilistic electric system reliability modeling. This study highlights the ways in which interregional cooperation, along with improvements in technology such as energy storage systems, can provide very high levels of reliability under the Transition Scenario.

The primary limitation of this analysis is the lack of important resource options for balancing load—interregional transfers and demand response—that would almost certainly play a key role in a clean-energy future; and indeed that are in widespread use today, and that were an important element of the BBAU 2011 Transition Scenario. Use of these resources would almost certainly substantially reduce or eliminate regional imbalances, and would make system operations more efficient and economical. On the other hand, the fact that the regions were almost always able to balance load *without* these resources adds to our confidence in the capability of the Transition Scenario.

Table 1. Days and hours in which generation exceeds load and days and hours in which generation does not meet load within a region.

	Load Surplus Events		Load Underserved Events	
	# Days	# Hours	# Days	# Hours
Arizona/New Mexico	34	81	7	12
California	96	394	16	52
Northwest	40	121	56	486
Rocky Mountains	0	0	0	0
Texas	300	3,389	0	0
Eastern Midwest	35	159	0	0
Northeast	121	509	0	0
South Central	170	1,063	0	0
Southeast	112	410	11	16
Western Midwest	263	1,692	0	0

The BBAU 2011 Transition Scenario resource mix was never intended to be an “optimal” scenario. Our expectation is that improvements in technology and operational practices over the coming decades will eclipse the resource options and practices that we can envision today. Nonetheless, we believe that providing a comprehensive, feasible vision for a clean energy future (and highlighting the technological challenges such a future presents) is an important contribution to facilitating this crucial transition. The sooner that we undertake in-depth analyses of resource and integration needs, the more options will be available for meeting future resource adequacy requirements in a cost-effective way.

Although it is unlikely that BBAU 2011’s Transition Scenario will ultimately provide the most cost effective or elegant nationwide low-carbon energy solution, this study suggests that it will be

feasible to reliably integrate the high levels of zero-carbon energy called for by the Transition Scenario. Achieving this future will require only incremental improvements in technology and operational practices, including continuation of the current trend toward better interregional coordination and intermittent resource capacity forecasting.

Our findings are consistent with other studies, such as MIT 2012, which suggest that much of the U.S. grid could integrate and balance many times the current level of renewables with no additional reliability issues. Recent improvements in both renewable technologies themselves and in the technologies that are used to control and balance the grid have been proceeding at a rapid pace, and the incentives and rewards for success in this area continue to drive substantial progress. In contrast, the alternative—continuing to rely on increasing combustion of fossil fuels to generate electricity, and producing ever-increasing levels of greenhouse gases—is far less feasible, and presents much more daunting technical, economic, and social challenges to human and environmental welfare. In comparison, the challenge of integrating increasing levels of solar and wind power on the U.S. power grids requires only incremental improvements in technology and operational practices.

5. References & Data Sources

American Physical Society (APS) Panel on Public Affairs. 2010. *Integrating Electricity on the Grid*. November 2010.

Denholm, P., E. Ela, B. Kirby, and M. Milligan. 2010. *The Role of Energy Storage with Renewable Electricity Generation*. January 2010.

EnerNex Corporation. *Eastern Wind Integration and Transmission Study*. Prepared for the National Renewable Energy Laboratory (NREL). Published January 2010. Revised February 2011.

Federal Energy Regulatory Commission (FERC). FERC 2006 – 2010 Form No. 714 Dataset. *Annual Electric Balancing Authority Area and Planning Area Report*. 2011. Available at <http://www.ferc.gov/docs-filing/forms/form-714/data/form714-database.zip>. Accessed March 26, 2012.

GE Energy. *Western Wind and Solar Integration Study*. Prepared for the National Renewable Energy Laboratory (NREL). May 2010.

Keith, Geoff, Bruce Biewald, Ezra Hausman, Kenji Takahashi, Tommy Vitolo, Tyler Comings, and Patrick Knight. *Toward a Sustainable Future for the U.S. Power Sector: Beyond Business as Usual 2011*. Prepared by Synapse Energy Economics for the Civil Society Institute. November 2011.

Lew, D., D. Piwko, N. Miller, G. Jordan, K. Clark, and L. Freeman. *How Do High Levels of Wind and Solar Impact the Grid? The Western Wind and Solar Integration Study*. National Renewable Energy Laboratory. December 2010.

Massachusetts Institute of Technology (MIT). 2011. *The Future of the Electric Grid*. An Interdisciplinary MIT Study.

National Renewable Energy Laboratory (NREL). PVWatts™ calculator. Available at: <http://www.nrel.gov/irredc/pvwatts/>. Accessed March 26, 2012.

North American Electric Reliability Corporation (NERC). *Balancing Authority Acronym List*. 2012. Available at <http://www.nerc.com/filez/ctrlarealist.htm>. Accessed March 26, 2012.

U.S. Bureau of Reclamation. *Facility Generation by Month (Rolling Data for last 10 Years)*. 2009. Available at <http://www.usbr.gov/power/data/10%20Year%20Rolling%20Monthly%20Generation%20by%20Facility.xls>. Accessed March 19, 2012.

U.S. Department of Energy (DOE). *2010 Wind Technologies Market Report*. Office of Energy Efficiency and Renewable Energy. June 2011.

U.S. Department of Energy (DOE). *Solar Energy Technologies Program*. Office of Energy Efficiency and Renewable Energy. September 2008.

U.S. Energy Information Administration (EIA). *Annual Energy Outlook 2011, with Projections to 2035*. April 2011.

U.S. Environmental Protection Agency (EPA). *The Emissions & Generation Resource Integrated Database (eGRID)*. eGRID2010 Version 1.1 Dataset. 2011. Available at http://www.epa.gov/cleanenergy/documents/egridzips/eGRID2010_Version1-1.zip. Accessed March 26, 2012.

Appendix A: Seasonal Results by Region

A. Northeast

In this section, we provide the 2050 model results for the Northeast region for: 1) Annual daily generation indicating selected seasonal weeks, 2) the spring week with the lowest demand, 3) the summer week with the highest peak demand, 4) the autumn week with the lowest demand, and 5) the winter week with the highest peak demand.

Figure A-1. Annual daily generation in the Northeast - 2050

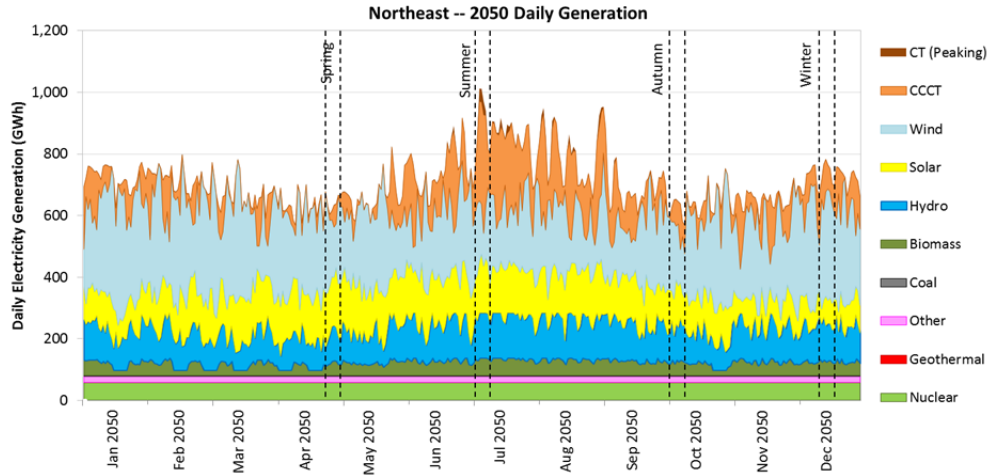


Figure A-2. Trough Spring Week in the Northeast - 2050

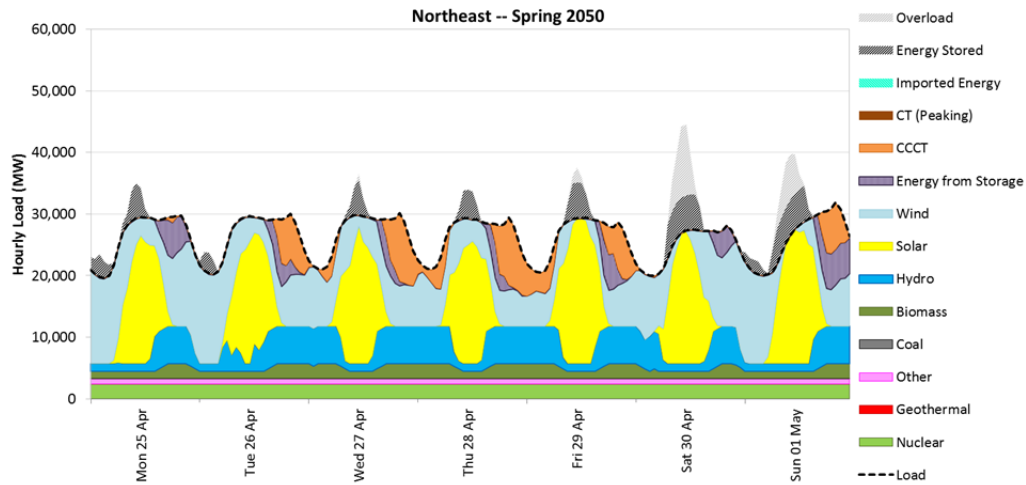


Figure A-3. Peak Summer Week in the Northeast - 2050

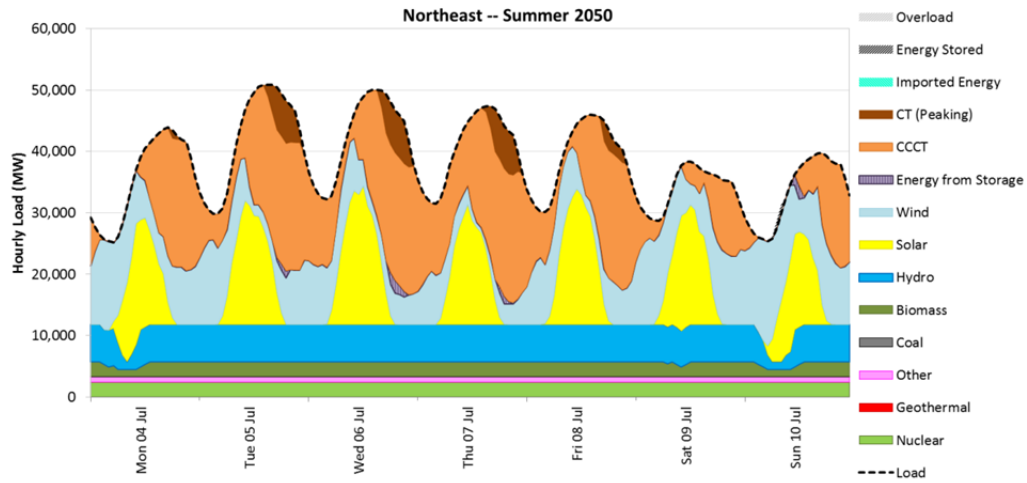


Figure A-4. Trough Autumn Week in the Northeast - 2050

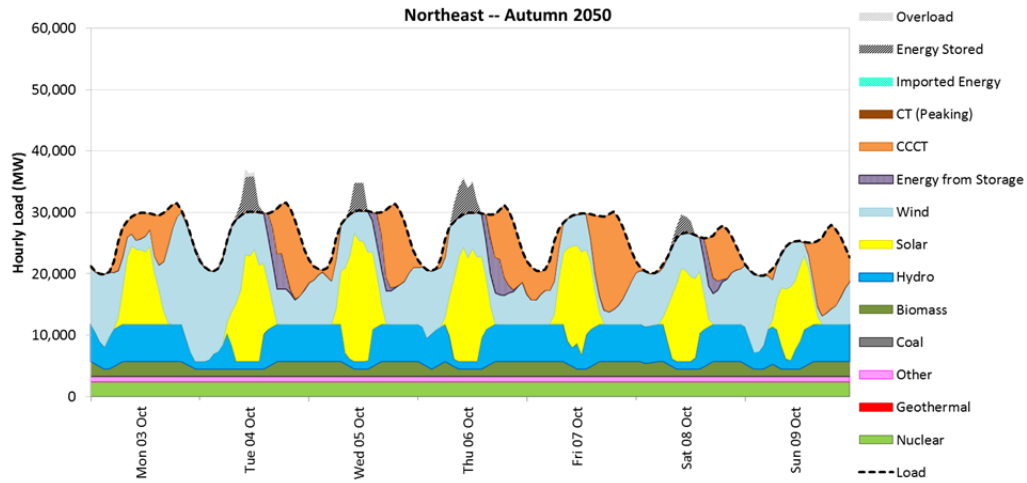
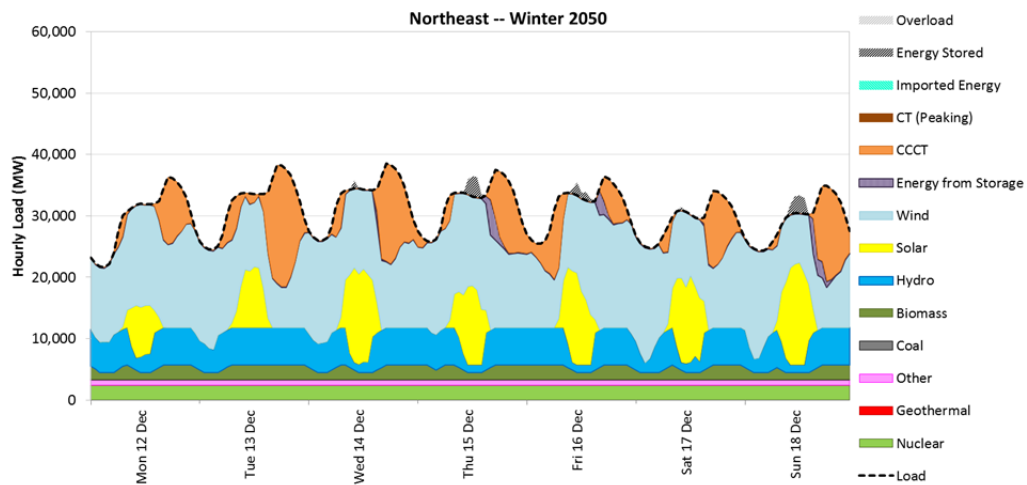


Figure A-5. Peak Winter Week in the Northeast - 2050



B. Eastern Midwest

In this section, we provide the 2050 model results for the Eastern Midwest region for: 1) Annual daily generation indicating selected seasonal weeks, 2) the spring week with the lowest demand, 3) the summer week with the highest peak demand, 4) the autumn week with the lowest demand, and 5) the winter week with the highest peak demand.

Figure A-6. Annual daily generation in the Eastern Midwest - 2050

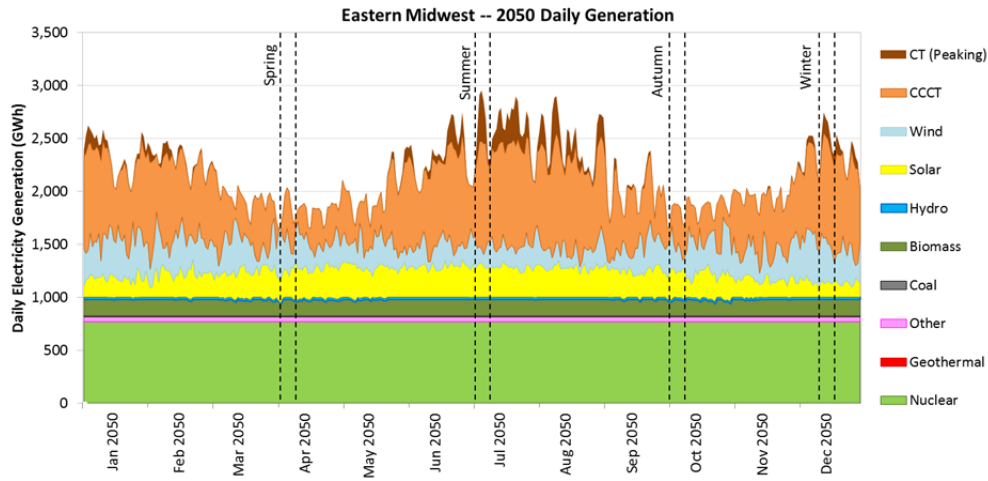


Figure A-7. Trough Spring Week in the Eastern Midwest - 2050

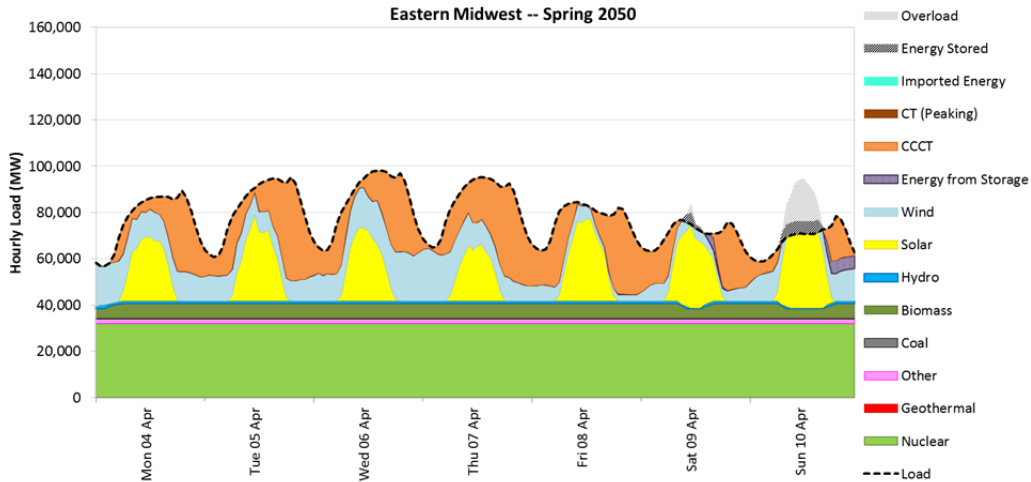


Figure A-8. Peak Summer Week in the Eastern Midwest - 2050

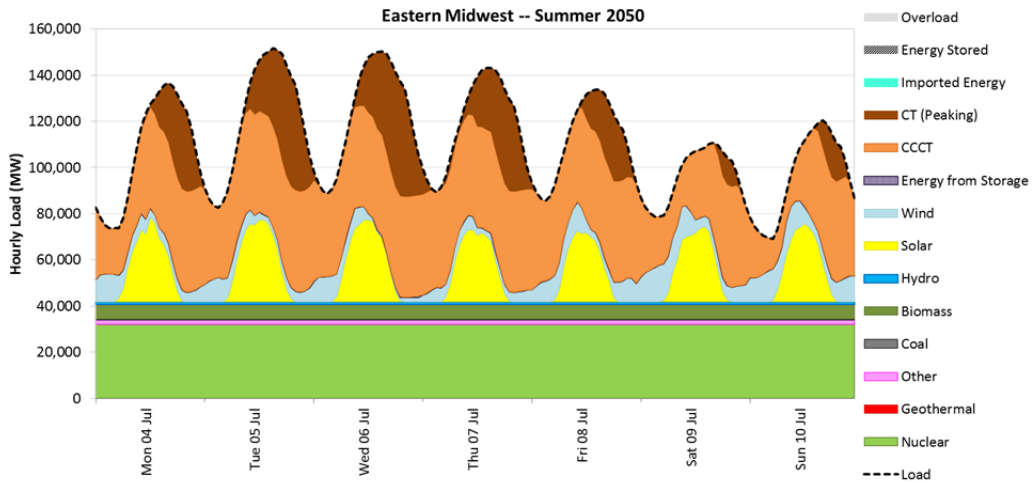


Figure A-9. Trough Autumn Week in the Eastern Midwest - 2050

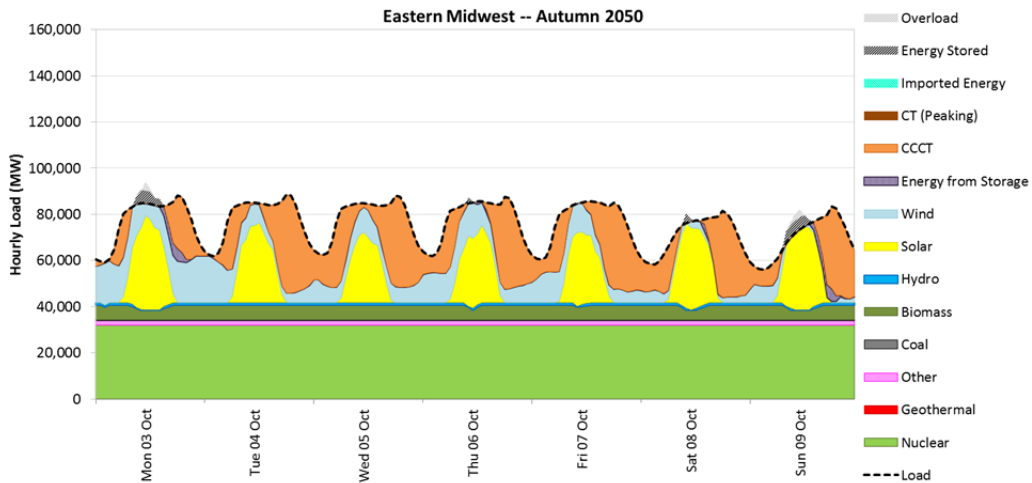
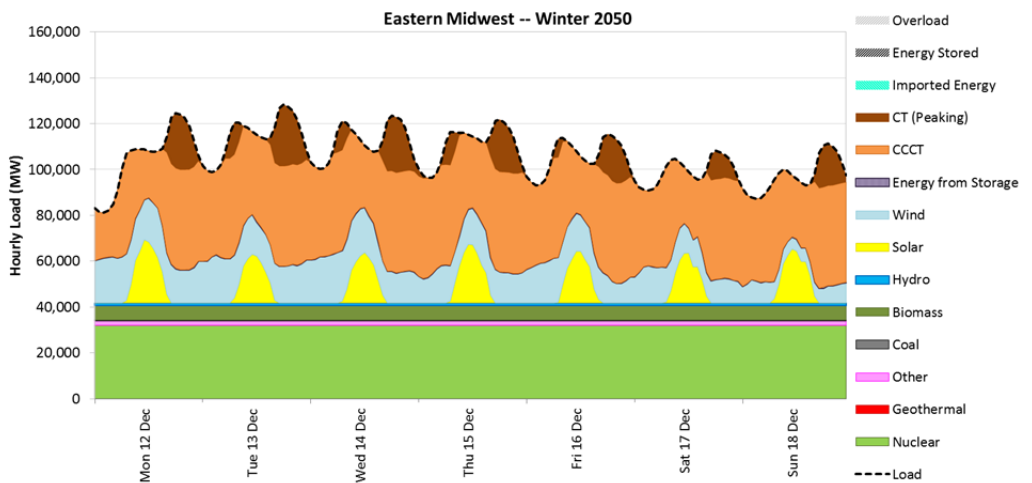


Figure A-10. Peak Winter Week in the Eastern Midwest - 2050



C. Western Midwest

In this section, we provide the 2050 model results for the Western Midwest region for: 1) Annual daily generation indicating selected seasonal weeks, 2) the spring week with the lowest demand, 3) the summer week with the highest peak demand, 4) the autumn week with the lowest demand, and 5) the winter week with the highest peak demand.

Figure A-11. Annual daily generation in the Western Midwest - 2050

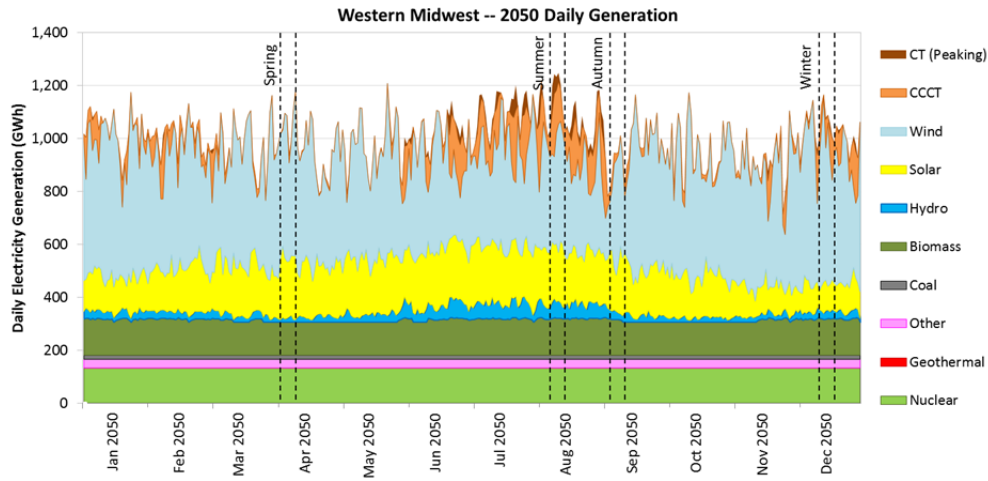


Figure A-12. Trough Spring Week in the Western Midwest - 2050

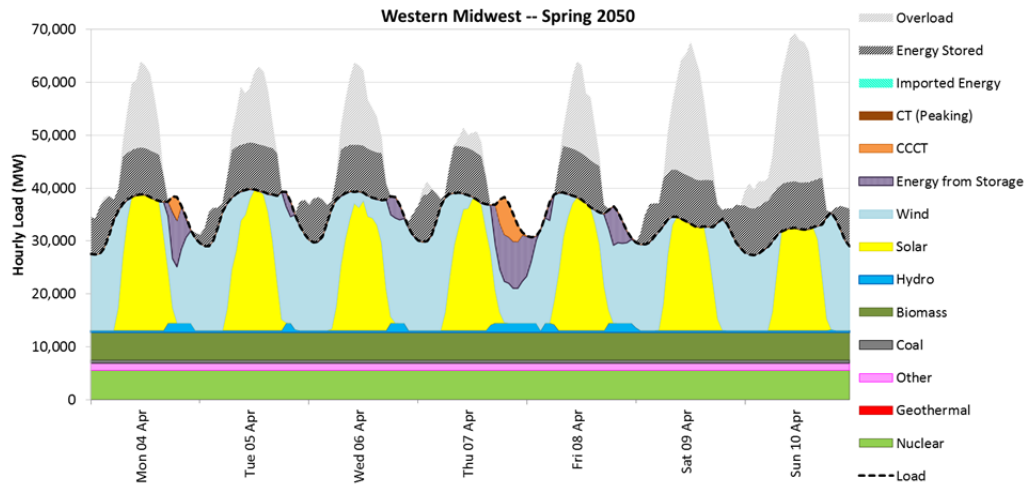


Figure A-13. Peak Summer Week in the Western Midwest - 2050

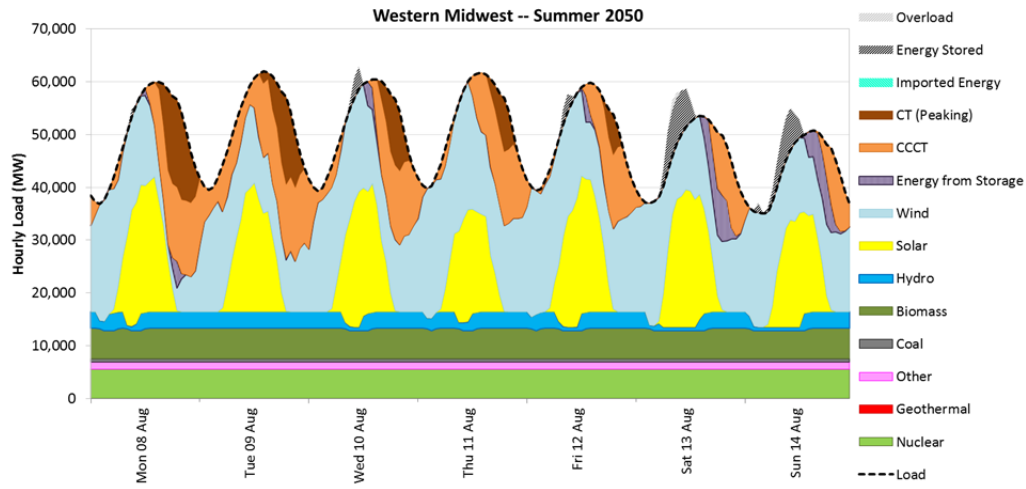


Figure A-14. Trough Autumn Week in the Western Midwest - 2050

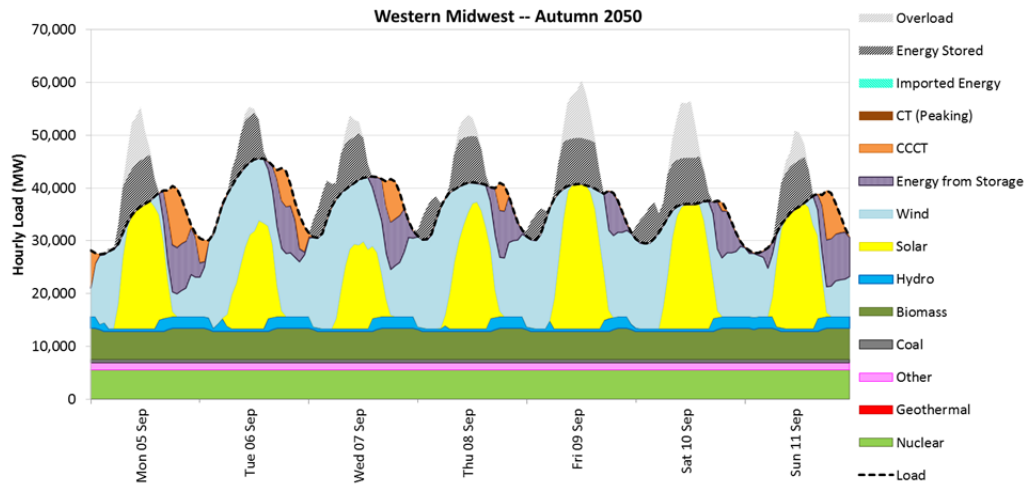
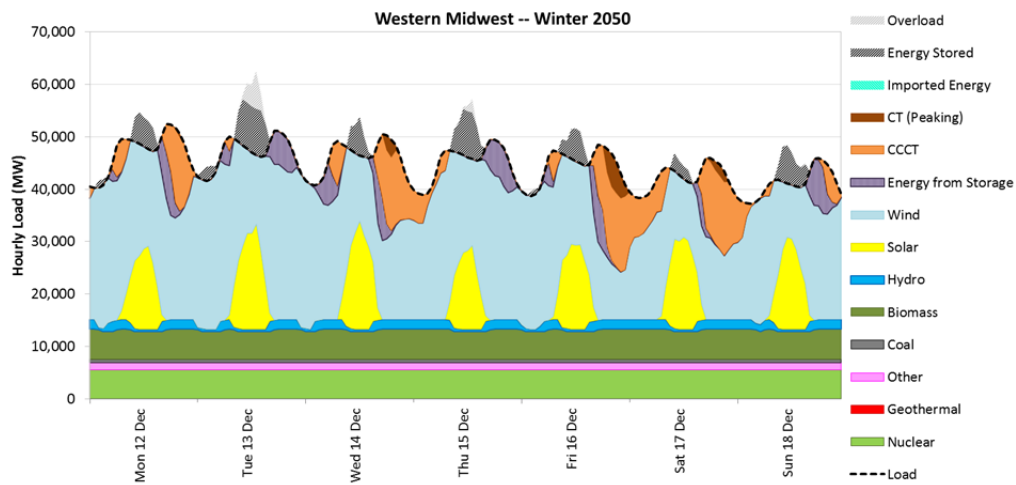


Figure A-15. Peak Winter Week in the Western Midwest - 2050



D. South Central

In this section, we provide the 2050 model results for the South Central region for: 1) Annual daily generation indicating selected seasonal weeks, 2) the spring week with the lowest demand, 3) the summer week with the highest peak demand, 4) the autumn week with the lowest demand, and 5) the winter week with the highest peak demand.

Figure A-16. Annual daily generation in the South Central - 2050

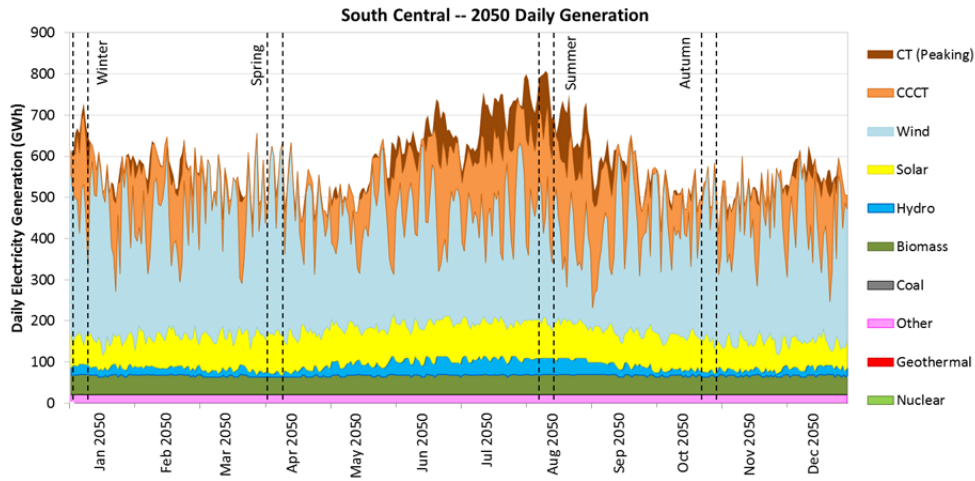


Figure A-17. Trough Spring Week in the South Central - 2050

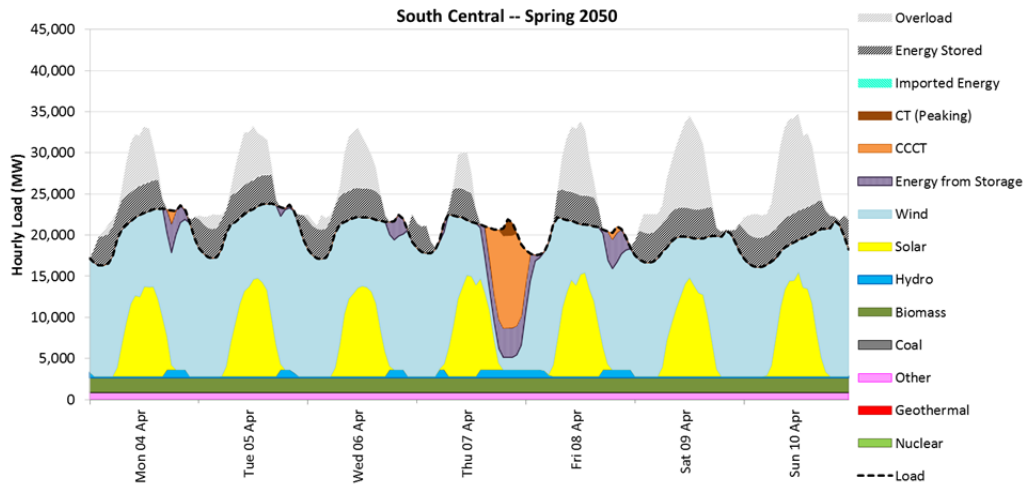


Figure A-18. Peak Summer Week in the South Central - 2050

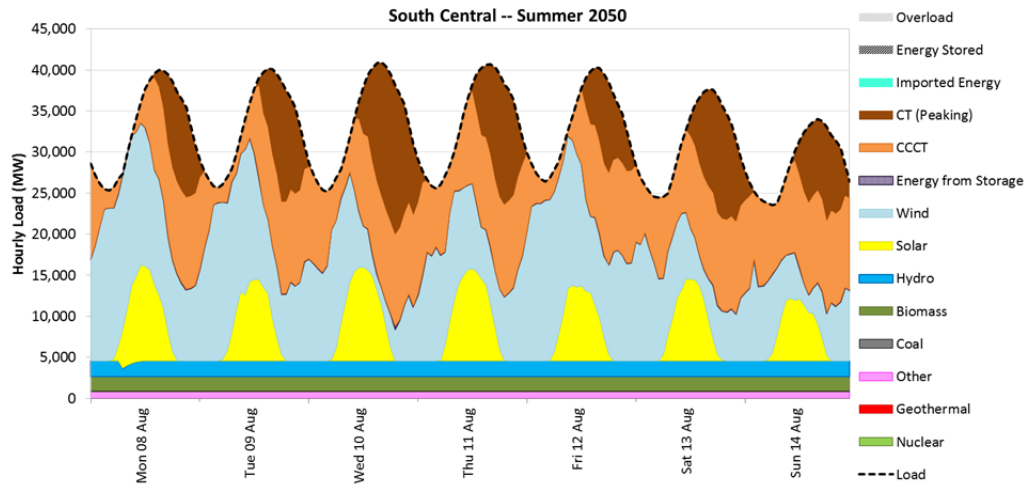


Figure A-19. Trough Autumn Week in the South Central - 2050

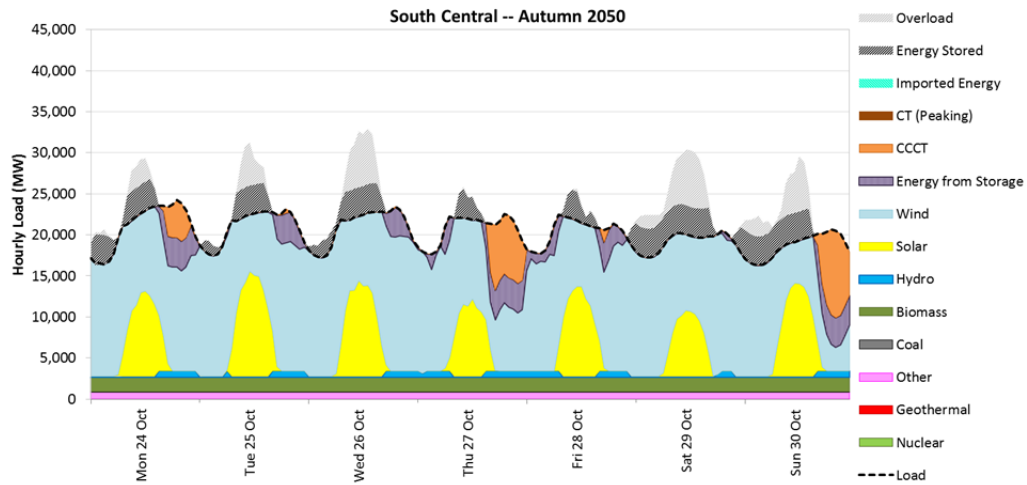
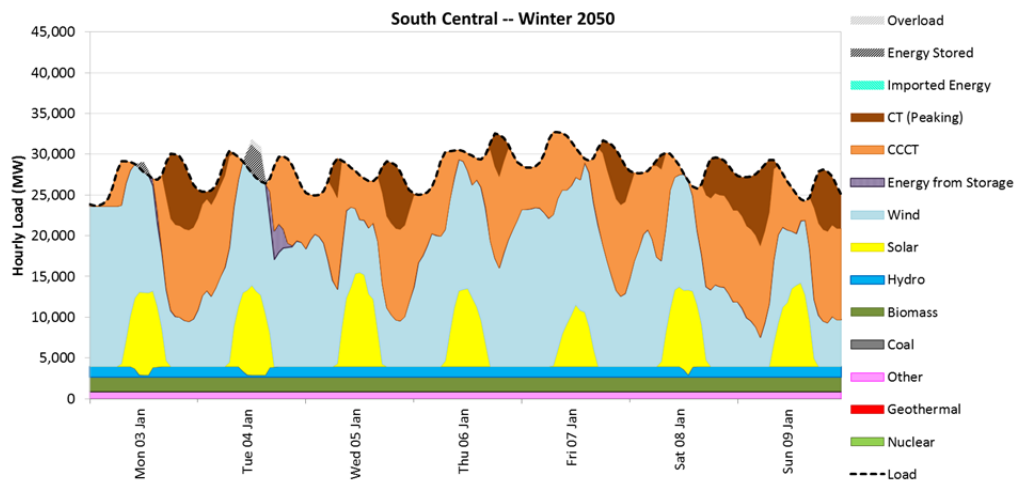


Figure A-20. Peak Winter Week in the South Central - 2050



E. Southeast

In this section, we provide the 2050 model results for the Southeast region for: 1) Annual daily generation indicating selected seasonal weeks, 2) the spring week with the lowest demand, 3) the summer week with the highest peak demand, 4) the autumn week with the lowest demand, and 5) the winter week with the highest peak demand.

Figure A-21. Annual daily generation in the Southeast - 2050

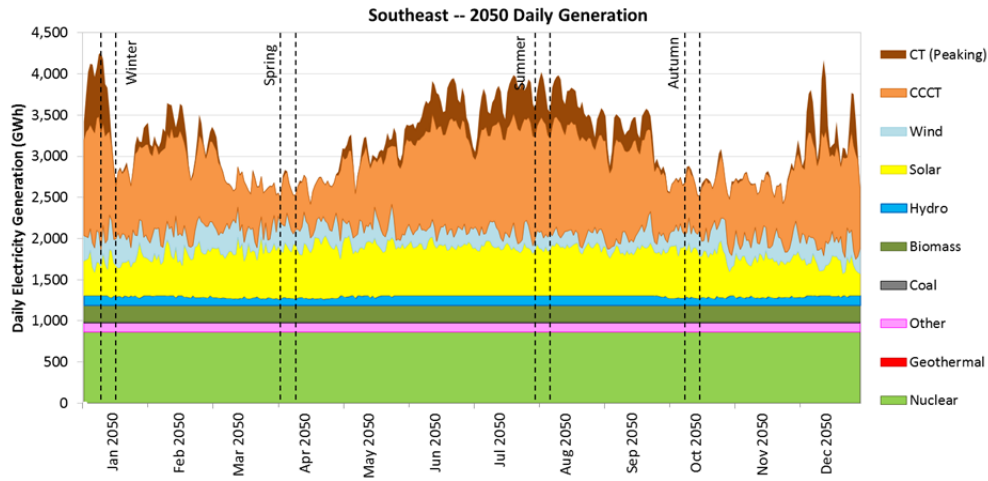


Figure A-22. Trough Spring Week in the Southeast - 2050

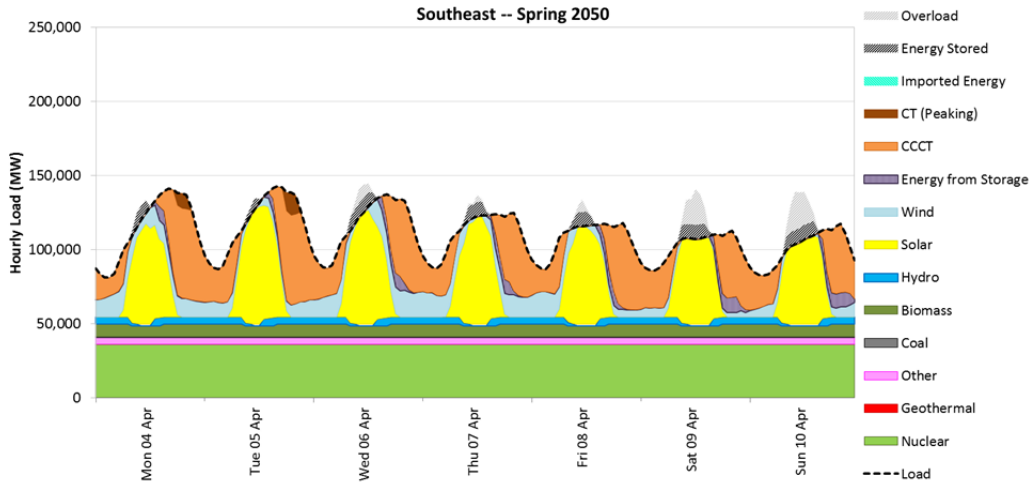


Figure A-23. Peak Summer Week in the Southeast - 2050

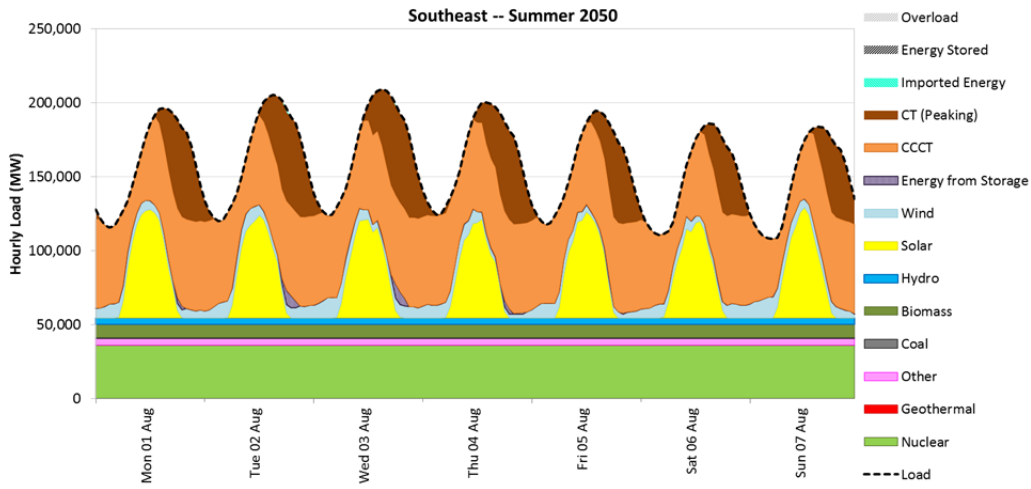


Figure A-24. Trough Autumn Week in the Southeast - 2050

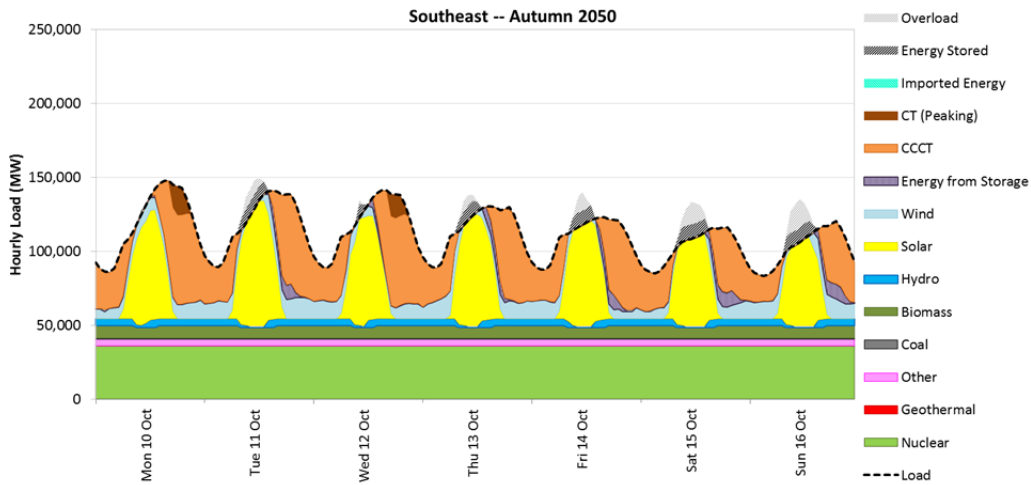
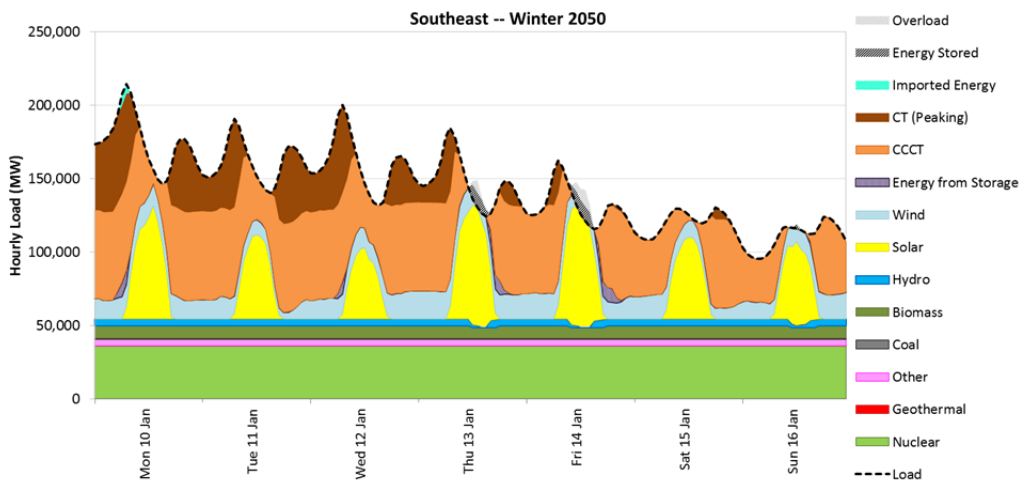


Figure A-25. Peak Winter Week in the Southeast - 2050



F. Texas

In this section, we provide the 2050 model results for the Texas region for: 1) Annual daily generation indicating selected seasonal weeks, 2) the spring week with the lowest demand, 3) the summer week with the highest peak demand, 4) the autumn week with the lowest demand, and 5) the winter week with the highest peak demand.

Figure A-26. Annual daily generation in Texas - 2050

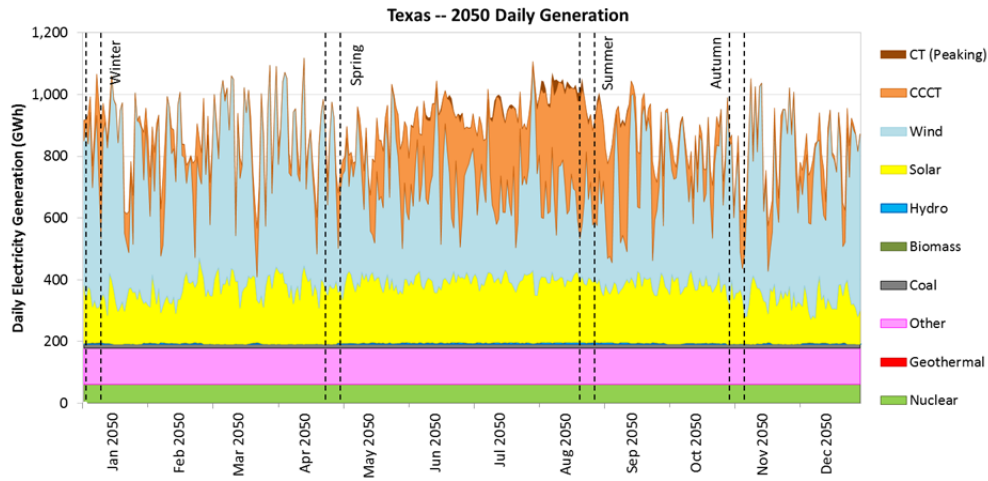


Figure A-27. Trough Spring Week in Texas - 2050

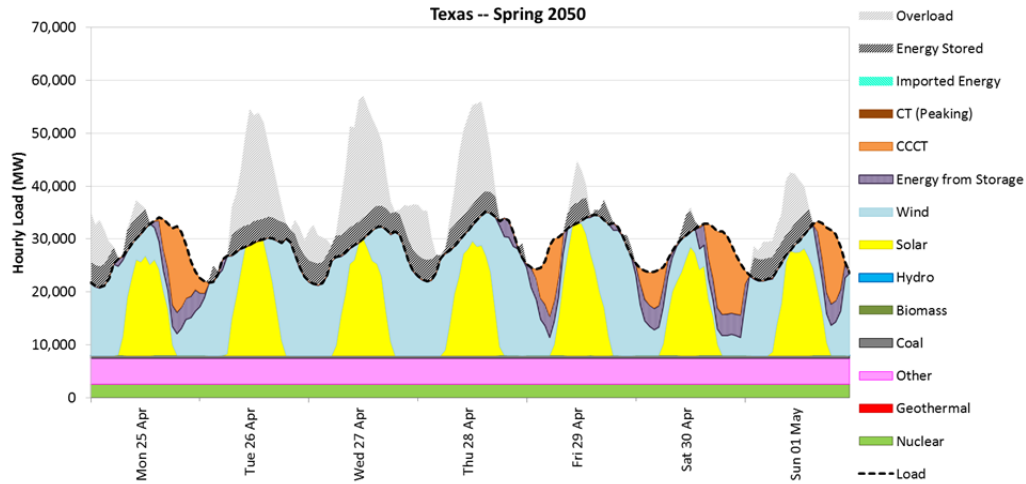


Figure A-28. Peak Summer Week in Texas - 2050

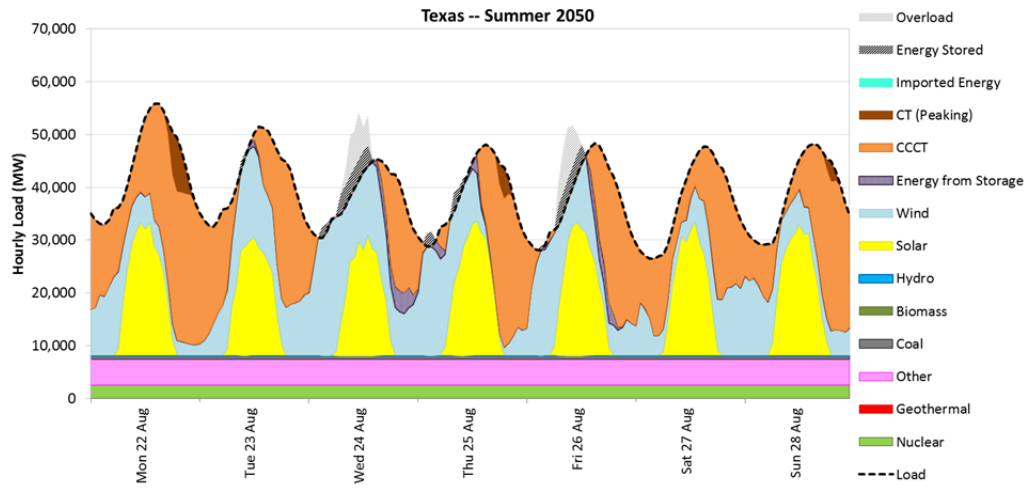


Figure A-29. Trough Autumn Week in Texas - 2050

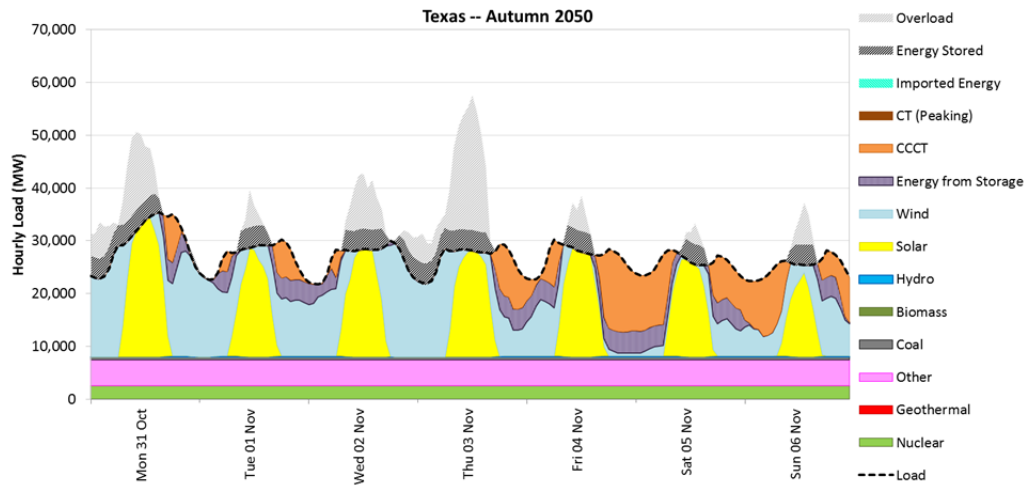
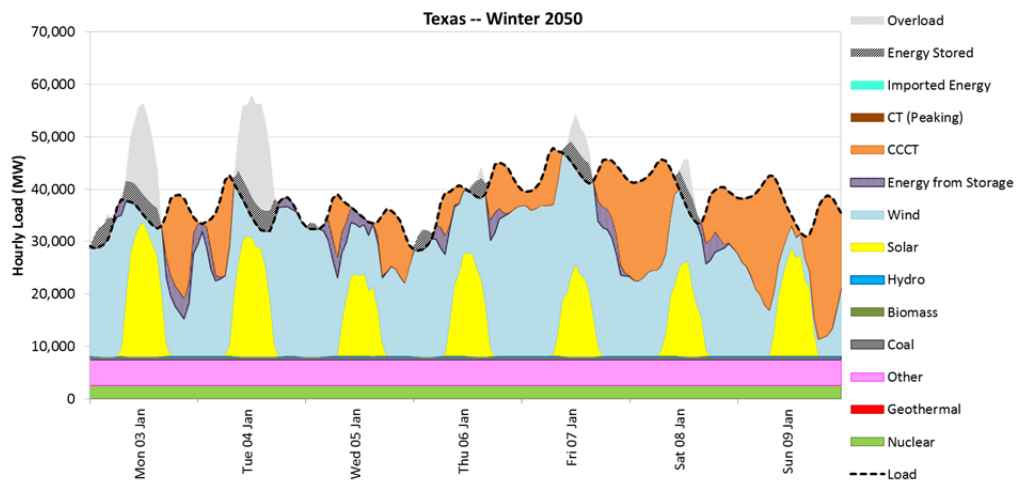


Figure A-30. Peak Winter Week in Texas - 2050



G. California

In this section, we provide the 2050 model results for the California region for: 1) Annual daily generation indicating selected seasonal weeks, 2) the spring week with the lowest demand, 3) the summer week with the highest peak demand, 4) the autumn week with the lowest demand, and 5) the winter week with the highest peak demand.

Figure A-31. Annual daily generation in California - 2050

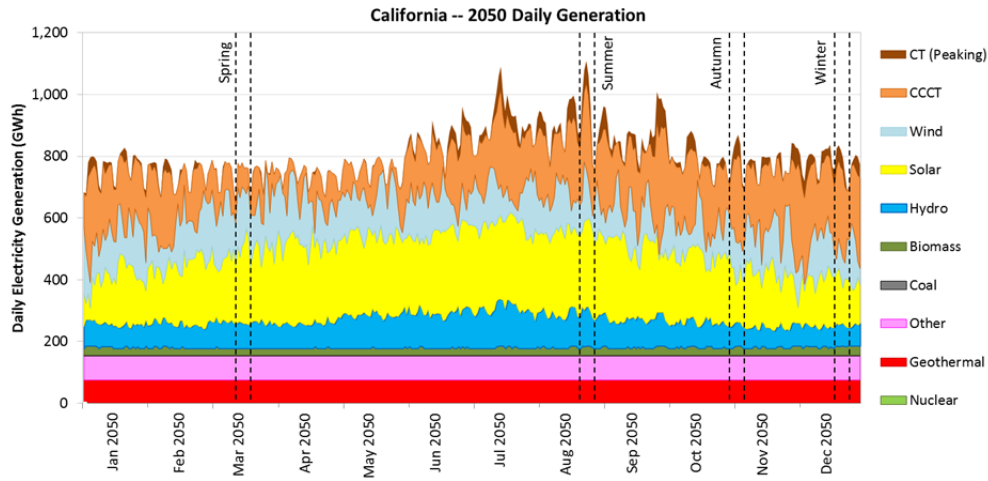


Figure A-32. Trough Spring Week in California - 2050

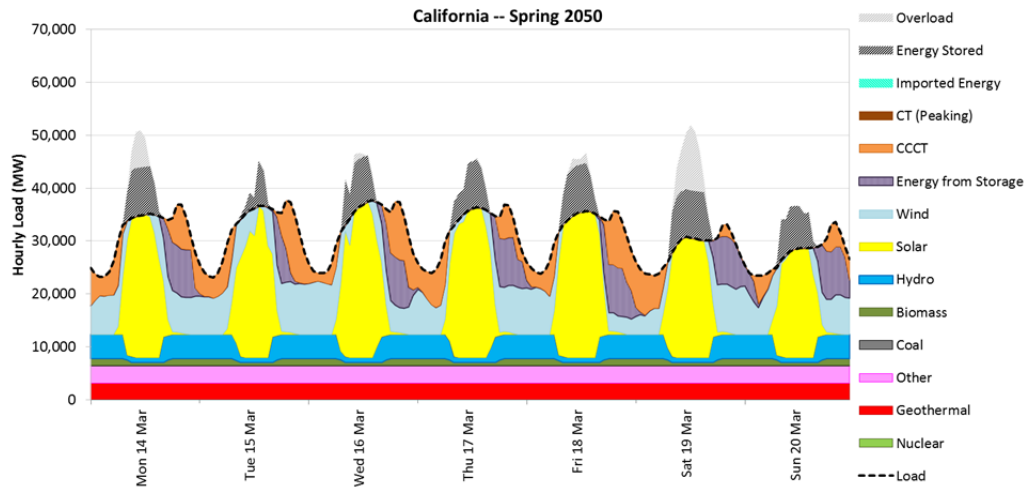


Figure A-33. Peak Summer Week in California - 2050

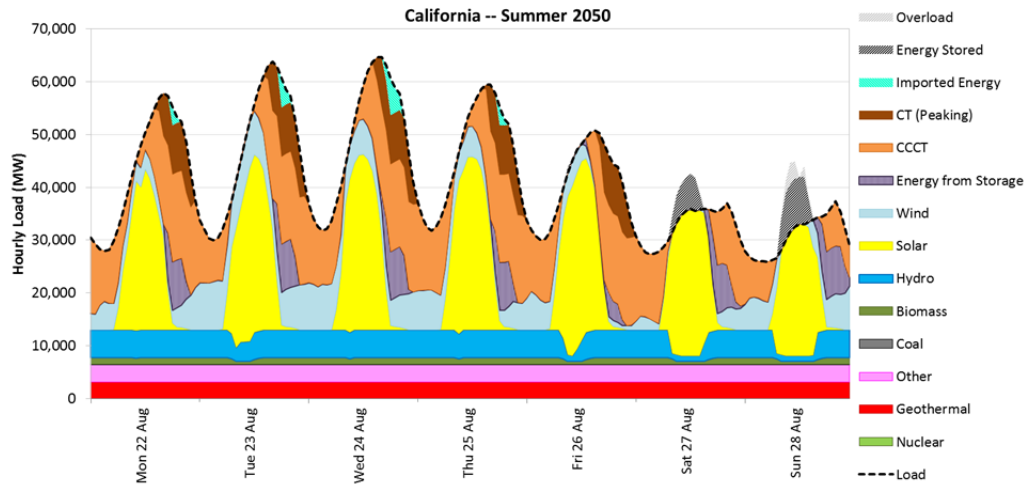


Figure A-34. Trough Autumn Week in California - 2050

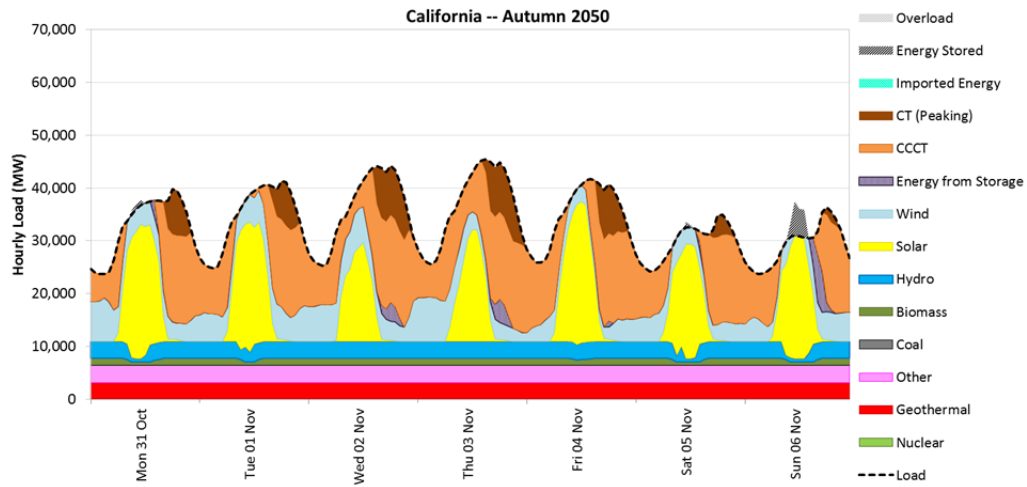
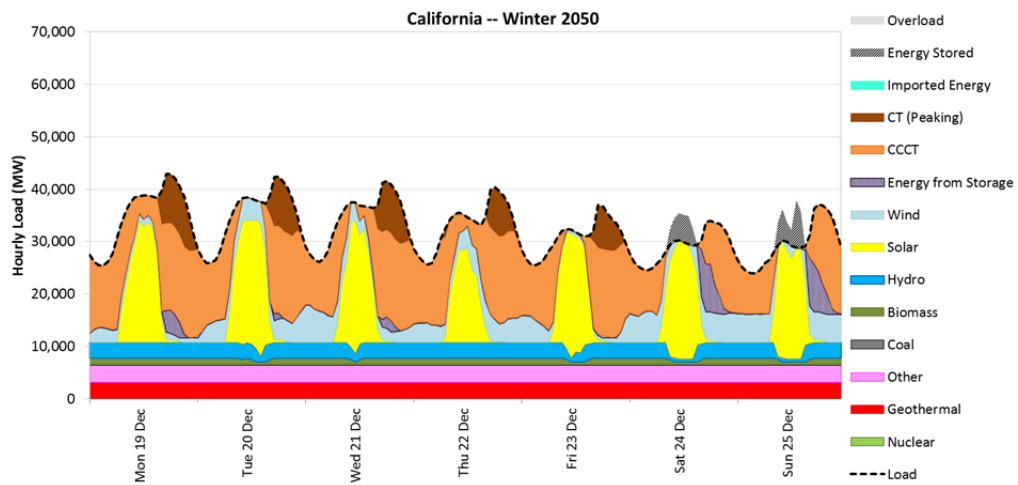


Figure A-35. Peak Winter Week in California - 2050



H. Arizona/New Mexico

In this section, we provide the 2050 model results for the Arizona/New Mexico region for: 1) Annual daily generation indicating selected seasonal weeks, 2) the spring week with the lowest demand, 3) the summer week with the highest peak demand, 4) the autumn week with the lowest demand, and 5) the winter week with the highest peak demand.

Figure A-36. Annual daily generation in Arizona/New Mexico - 2050

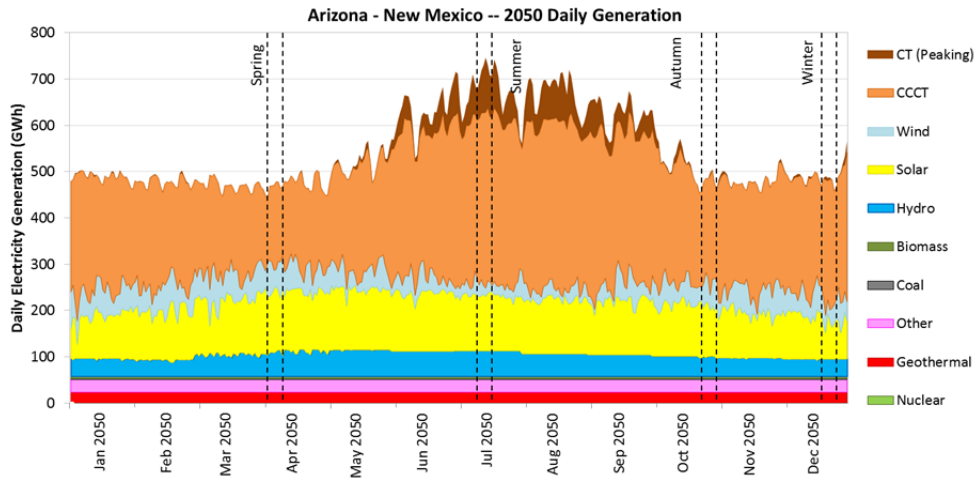


Figure A-37. Trough Spring Week in Arizona/New Mexico - 2050

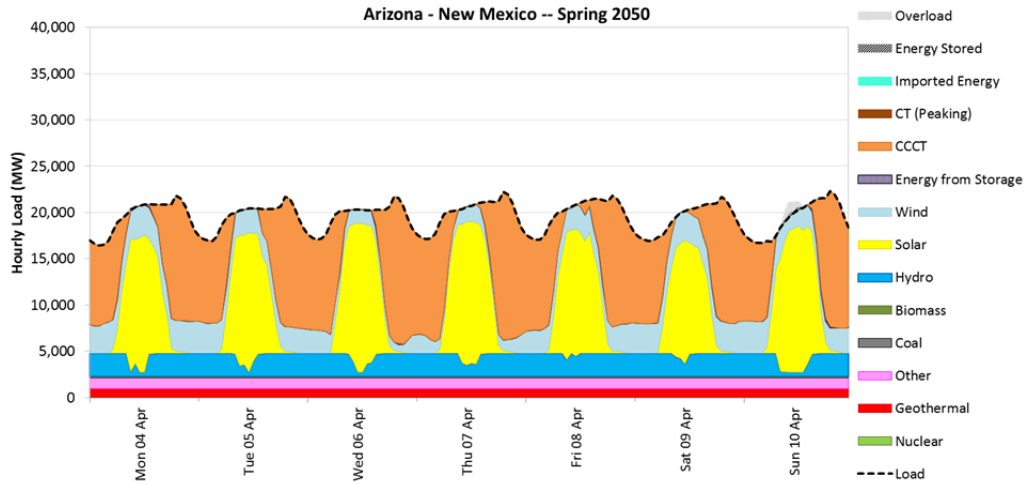


Figure A-38. Peak Summer Week in Arizona/New Mexico - 2050

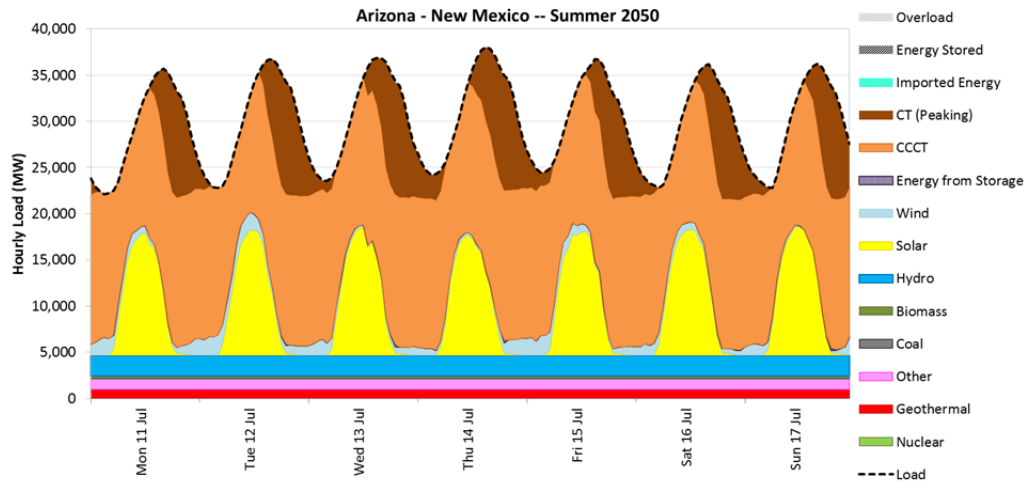


Figure A-39. Trough Autumn Week in Arizona/New Mexico - 2050

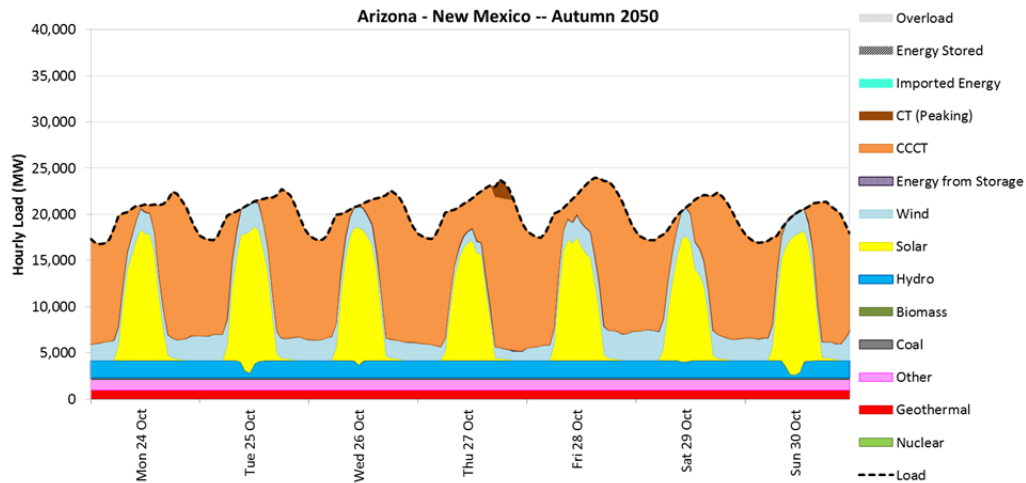
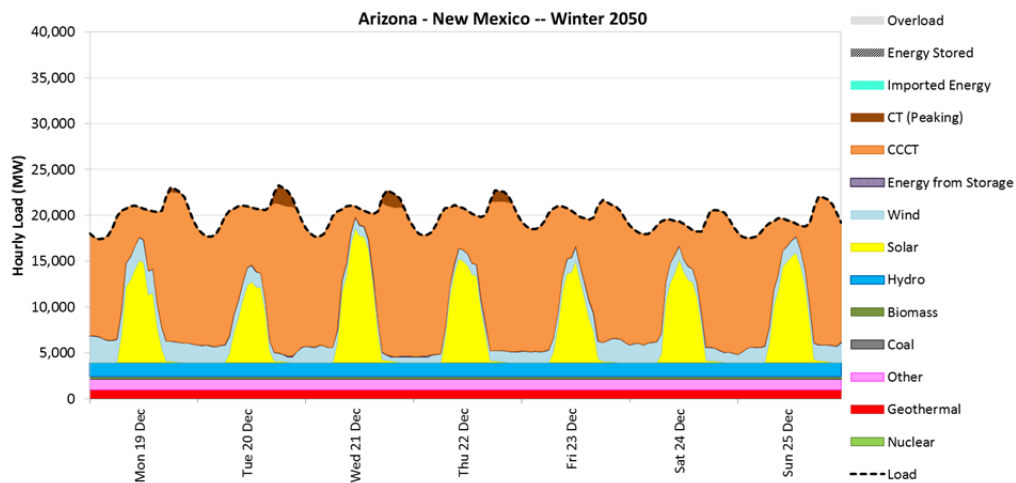


Figure A-40. Peak Winter Week in Arizona/New Mexico - 2050



I. Northwest

In this section, we provide the 2050 model results for the Northwest region for: 1) Annual daily generation indicating selected seasonal weeks, 2) the spring week with the lowest demand, 3) the summer week with the highest peak demand, 4) the autumn week with the lowest demand, and 5) the winter week with the highest peak demand.

Figure A-41. Annual daily generation in the Northwest - 2050

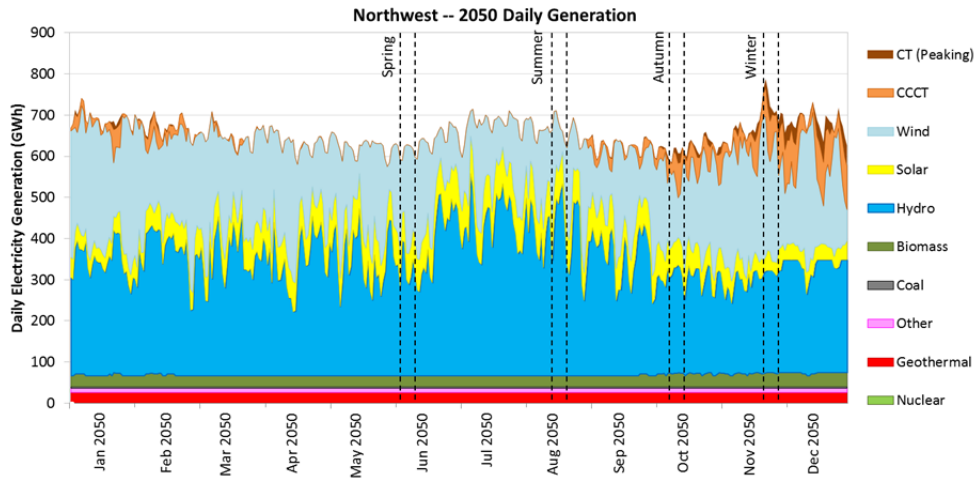


Figure A-42. Trough Spring Week in the Northwest - 2050

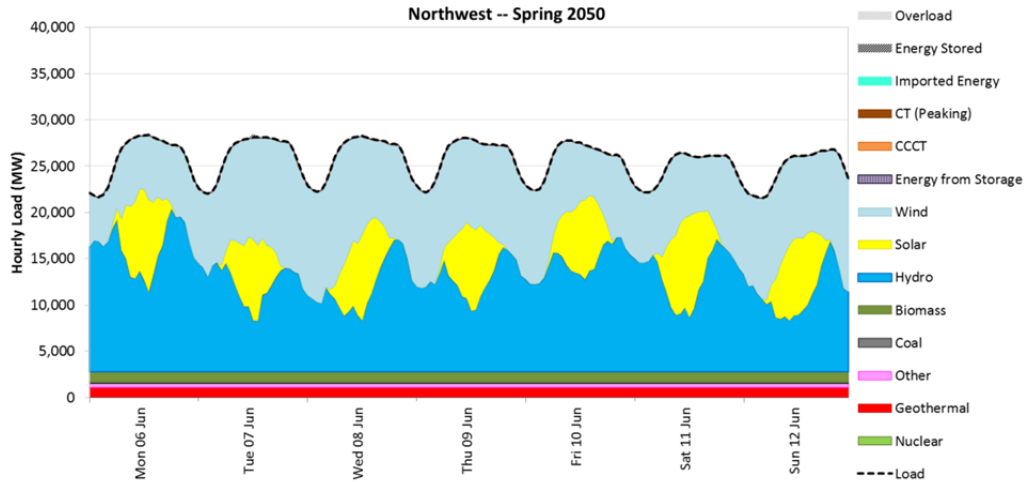


Figure A-43. Peak Summer Week in the Northwest - 2050

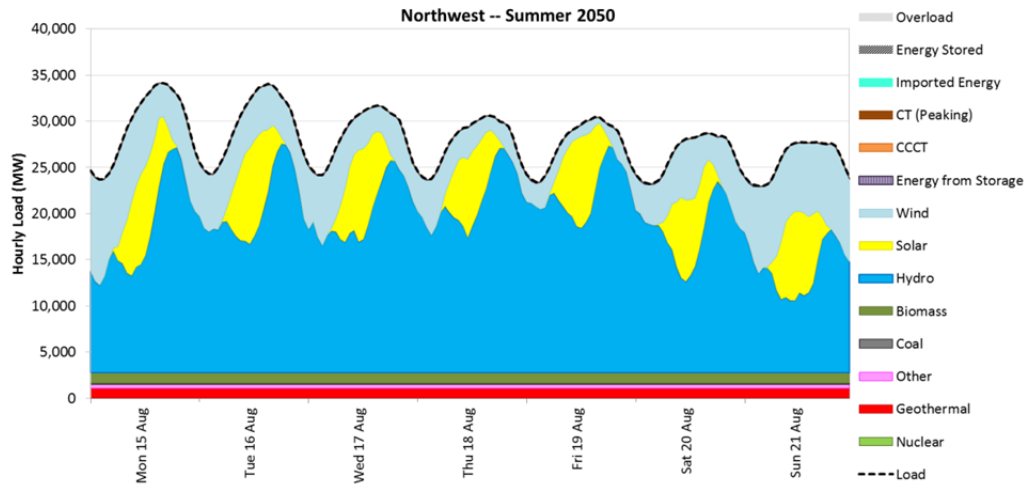


Figure A-44. Trough Autumn Week in the Northwest - 2050

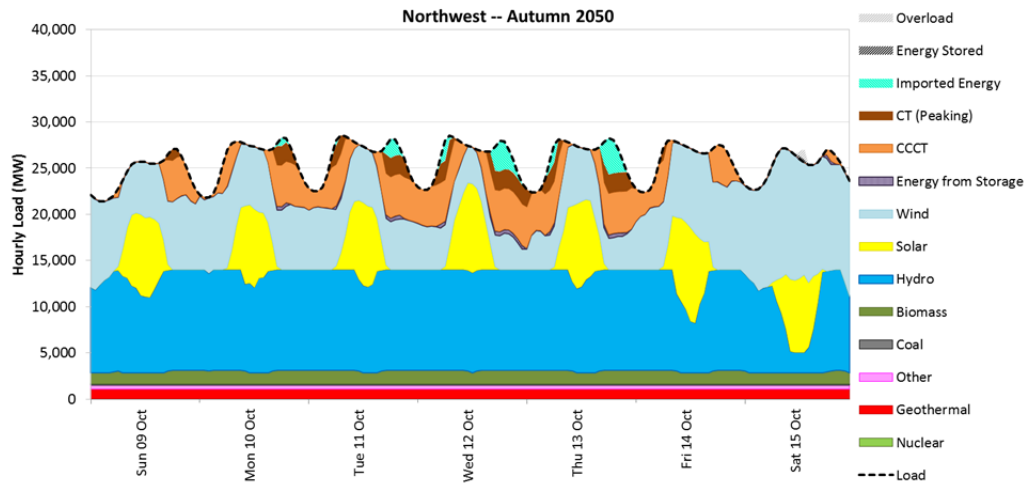
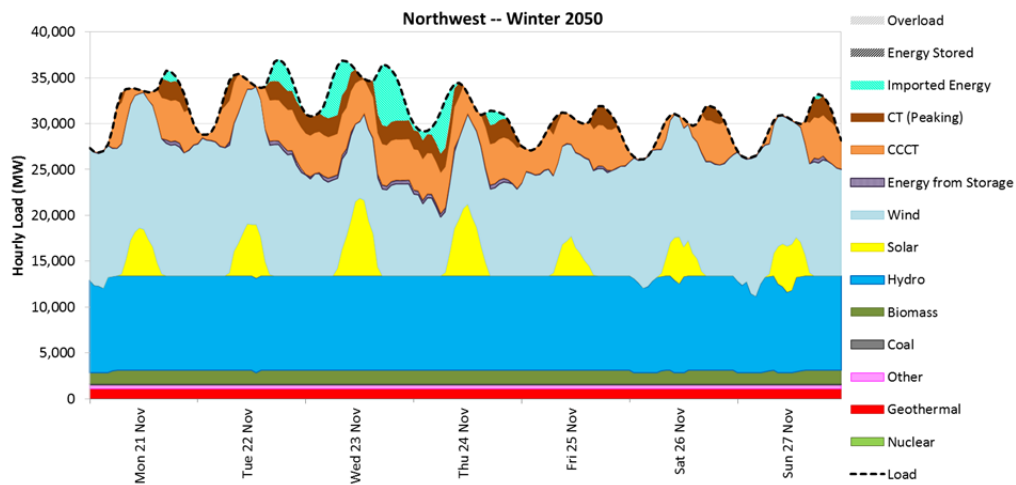


Figure A-45. Peak Winter Week in the Northwest - 2050



J. Rocky Mountains

In this section, we provide the 2050 model results for the Rocky Mountains region for: 1) Annual daily generation indicating selected seasonal weeks, 2) the spring week with the lowest demand, 3) the summer week with the highest peak demand, 4) the autumn week with the lowest demand, and 5) the winter week with the highest peak demand.

Figure A-46. Annual daily generation in the Rocky Mountains - 2050

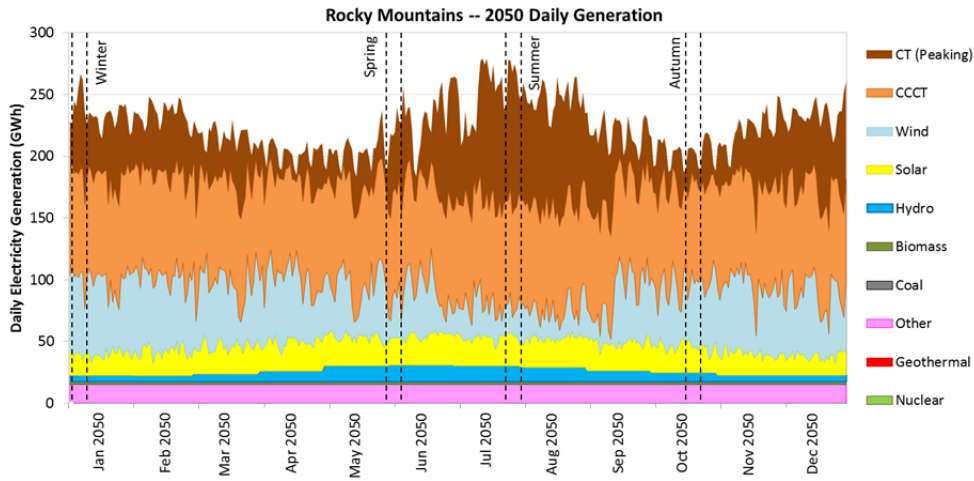


Figure A-47. Trough Spring Week in the Rocky Mountains - 2050

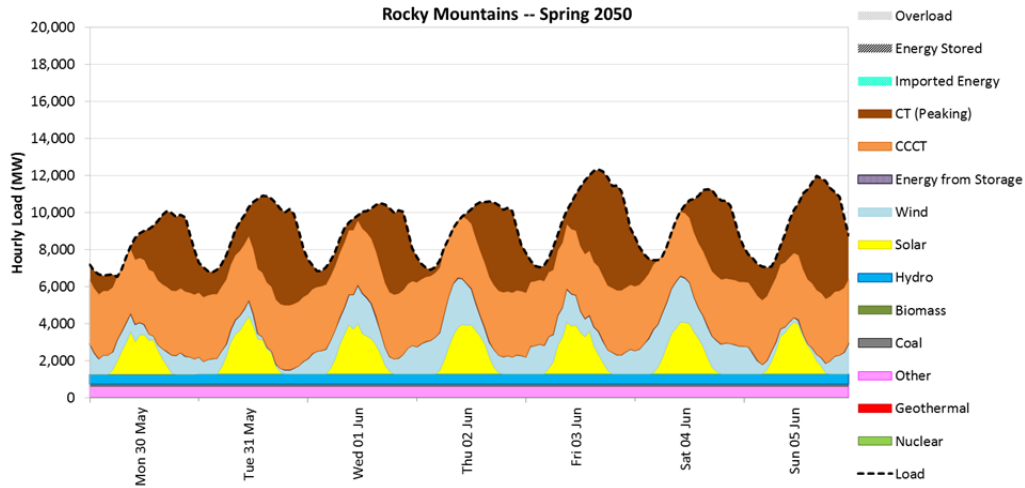


Figure A-48. Peak Summer Week in the Rocky Mountains - 2050

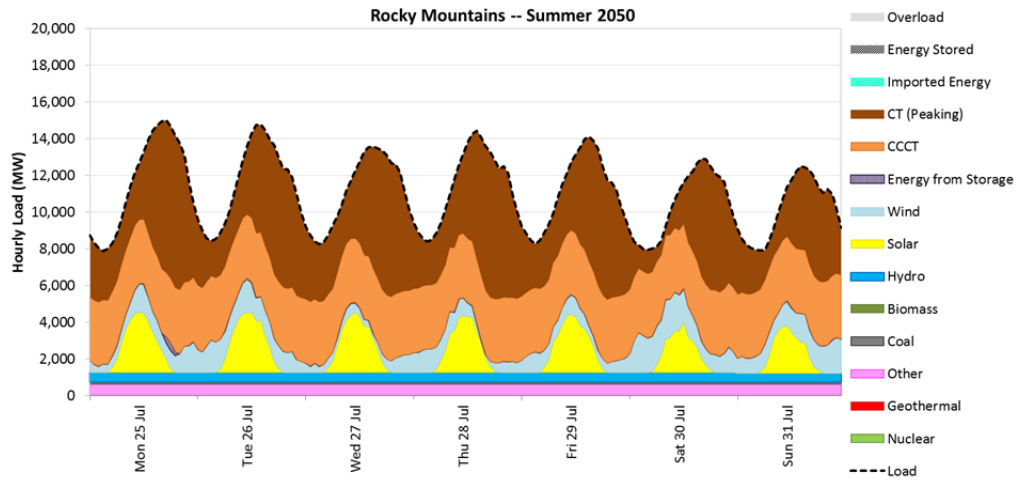


Figure A-49. Trough Autumn Week in the Rocky Mountains - 2050

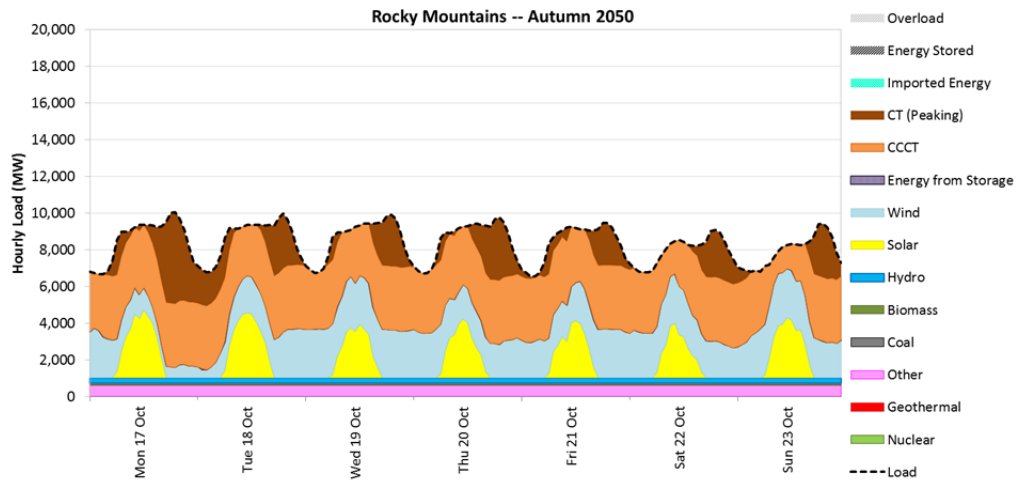
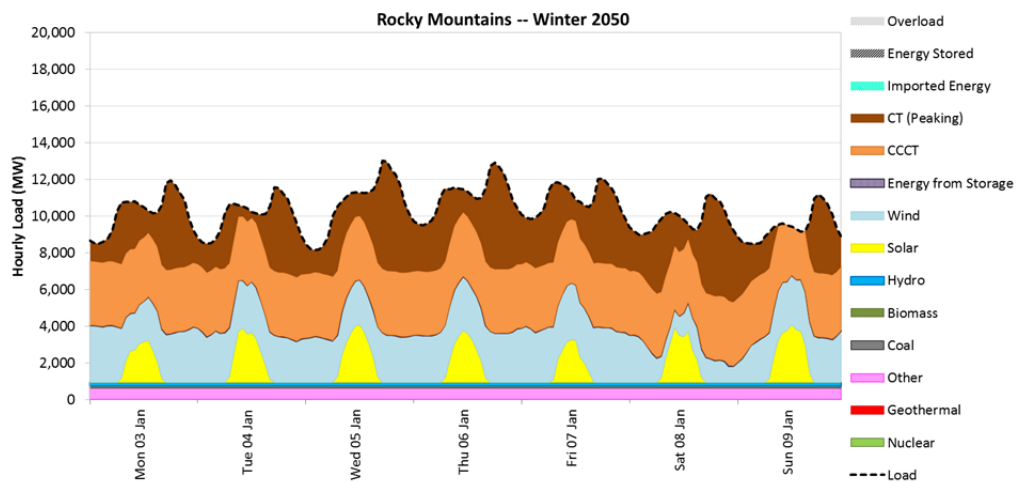


Figure A-50. Peak Winter Week in the Rocky Mountains - 2050



Appendix B: Model Dispatch Algorithm

The algorithm to determine which resources are dispatched, and how much, works by considering the resources in the following order and either (a) dispatching all of the resource, or (b) dispatching just enough to meet load.

1. Must Take Resources: the following resources are dispatched regardless of demand
 - a. Nuclear (nameplate capacity)
 - b. Geothermal (nameplate capacity)
 - c. Distributed generation including generic end use generation and fuel cells (average capacity factor)
 - d. Solar PV (hourly capacity factor for each region a geographic aggregate from NREL's PVWatts data set)
 - e. Solar Thermal (hourly capacity factor modeled using NREL's PVWatts data on a four hour delay)
 - f. River Must Run Hydro (annual capacity factors from CSI II report, modified monthly for CA, NW, AZNM, RM, WMW, and SC using *US Bureau of Reclamation Monthly Hydropower Generation Data by Facility* and modified for NE by assuming HydroQuébec's proposed transmission upgrades are approved). River Must Run is assumed to be 20% of total hydro capacity.
 - g. Wind (hourly capacity factor modeled using geographic aggregates from NREL's Eastern Wind Integration and Transmission Study (EWITS) as well as NREL's Western Wind and Solar Study (WWSIS), 100 meter hub height. TX wind was modeled using the NREL WWSIS study data points located solely in northern and west Texas).
 - h. Coal (nameplate capacity). If coal is dispatched (see below), the maximum amount of MW of coal dispatched over the next week is calculated, and every hour for the week requires that at least 25% of that maximum be dispatched. Furthermore, ability to ramp upward or downward is limited to 25% of the aforementioned maximum. To determine if coal is dispatched at all, a three pronged test is administered with coal hypothetically dispatched with no constraints on ramp rates, minimum run time, or minimum down time. An affirmative response to any of the three tests results in coal dispatched for the week:
 - i. In addition to the must take and dispatchable resources, the energy from the coal plants was necessary to meet load
 - ii. Some amount of coal generation was dispatched a minimum of 85 hours
 - iii. The capacity factor of the coal dispatched *as a function of the maximum hourly amount of coal dispatched* exceeded 40%
 - i. Biomass (nameplate capacity). Biomass is dispatched using the exact same algorithm as coal.



2. Overgeneration: the following resources are dispatched at up to their full capacity
 - a. New Other Storage (nameplate capacity). The amount of energy stored is accumulated at 70% of the excess generation to account for storage inefficiencies. The quantity of energy stored is not bounded from above.
 - b. Pumped Hydro Storage (nameplate capacity). Same as New Other Storage.
3. Dispatchable resources: the following resources are dispatched at up to their full capacity
 - a. Dispatchable Hydro (capacity as in River Must Run Hydro). Dispatchable Hydro is assumed to be 80% of total hydro capacity. Note that the RMR/Dispatchable ratio effects how much surplus energy is generated during times of surplus, but doesn't impact the analysis in times of possible shortage.
 - b. Coal. If dispatched for the week (see 1.h.), nameplate capacity minus the quantity dispatched in (1.h) is available.
 - c. Biomass. If dispatched for the week (see 1.i.), nameplate capacity minus the quantity dispatched in (1.i) is available.
 - d. New Other Storage. If there is energy in new other storage generated in earlier hours, the minimum of the nameplate capacity of the new other storage and the total energy stored in new other storage is available.
 - e. Pumped Hydro. If there is energy in pumped hydro storage generated in earlier hours, the minimum of the nameplate capacity of the pumped hydro storage and the total energy stored in pumped hydro facilities is available.
 - f. CCCT (nameplate capacity)
 - g. CT (nameplate capacity)
4. Emergency Storage: the following resources are dispatched at up to their full capacity
 - a. New Other Storage. If there is still an energy shortage and new other storage wasn't dispatched to its full nameplate capacity (3.d.), the model assumes that the dispatch organization used forecasts to predict a possible energy storage and ensured that there was enough energy stored so that the resource could be dispatched in this hour at full capacity.
 - b. Pumped Hydro Storage. If there is still an energy shortage and pumped hydro storage wasn't dispatched to its full nameplate capacity (3.d.), the model assumes that the dispatch organization used forecasts to predict a possible energy storage and ensured that there was enough energy stored so that the resource could be dispatched in this hour at full capacity.
5. Import/export: if there remains a shortage, energy is imported from neighboring regions which have surplus capacity