WECC

WECC 2038 Scenarios Reliability Assessment

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1. Executive Summary

This report presents the results and analysis of potential risks to the reliability of the Western Interconnection associated with potential futures on a 20-year time horizon, relative to 2018 when the WECC 2018/2019 study cycle began. The WECC 2038 Scenarios were developed by the WECC Scenario Development Subcommittee (SDS). The 2028 ADS PCM served as the foundational model from which 2038 Scenarios and Reference Case were created by extending the models another 10 years as discussed later in this report.

An old Danish proverb states "it's difficult to make predictions, especially about the future." In scenario planning, the goal is not to predict the future, but to investigate the range of plausible futures. Long-term planning models are not absolute and predictive. There are always gaps. The study results discussed in this report are not meant to be a prediction of the future, but an imagination of plausible energy futures and underlying drivers. WECC uses scenario planning to imagine what long-term risks to the reliability of the Western Interconnection are plausible and what strategies need to be considered to reduce exposure to those risks.

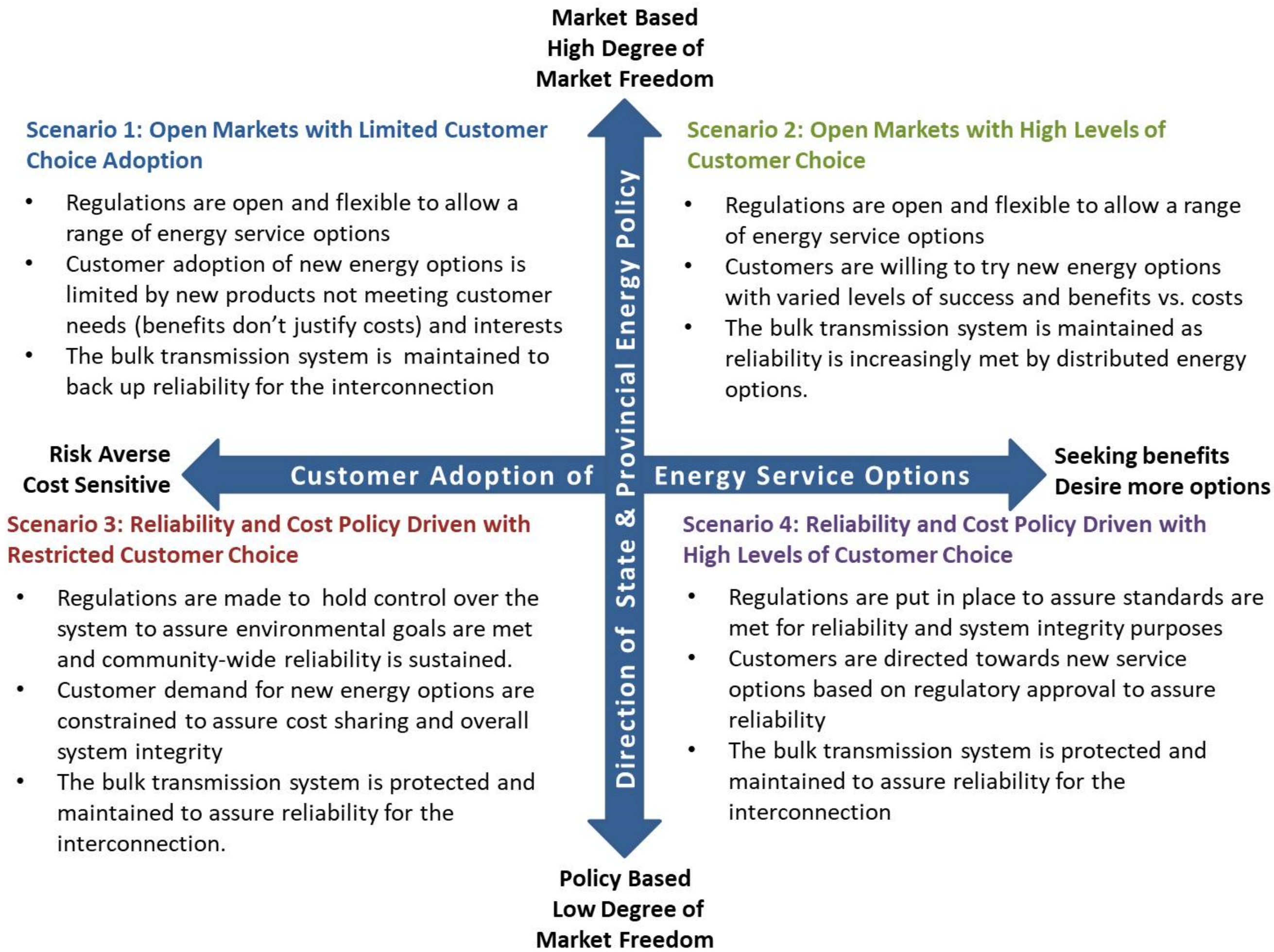
The WECC 2038 Scenarios in this report were studied from this perspective. Scenario planning is a stakeholder driven process that begins with the creation of a focus question. The focus question for the 2038 Scenarios is:

> *How might customer demand for electric services in the Western Interconnection evolve as new technologies and policies create more market options, and with that, what risks and opportunities may emerge for the power industry in sustaining electric reliability?*

The Scenarios Matrix, shown in Figure 1, was created from the focus question to help establish context by developing key narratives that consider:

- Customer adoption of energy service options; and
- Direction of state and provincial energy policy.

Figure 1: WECC 2038 Scenarios Matrix [12]



Recently, new energy service options have been emerging at an accelerated pace that have traditionally been dominated by non-electric technologies. This trend toward electrification could have a significant impact on the Western Interconnection. How consumers, policy makers, and markets may respond is uncertain. The purpose of this study is to assess the risks to future grid reliability in the context of the focus question and assumptions set out in the WECC 2038 Scenario Matrix.

Motivation

In the past, growth in electricity consumption has slowed as technology advancements have matured and consumer adoption of available service options have leveled off as encompassed in the findings of the NREL Electrification Futures Study (EFS) and shown in Figure 2.

Figure 2: Historic Electricity Consumption Trend [1]

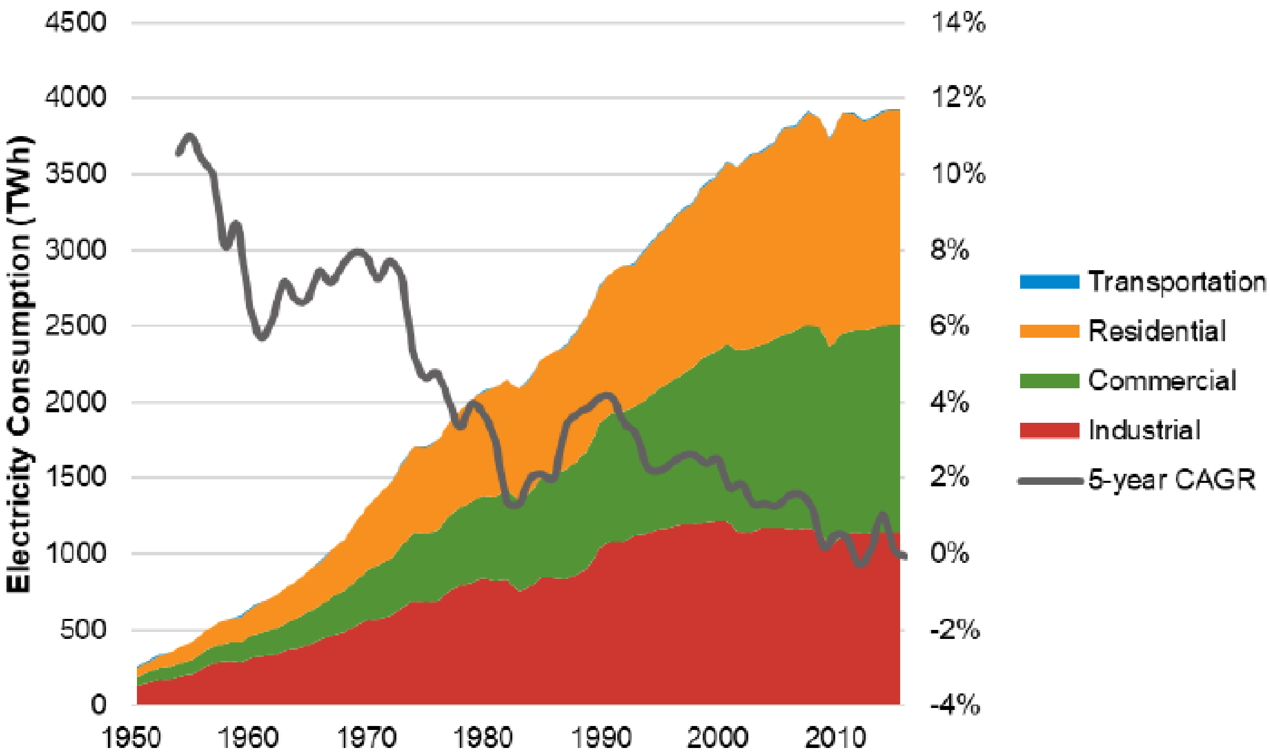
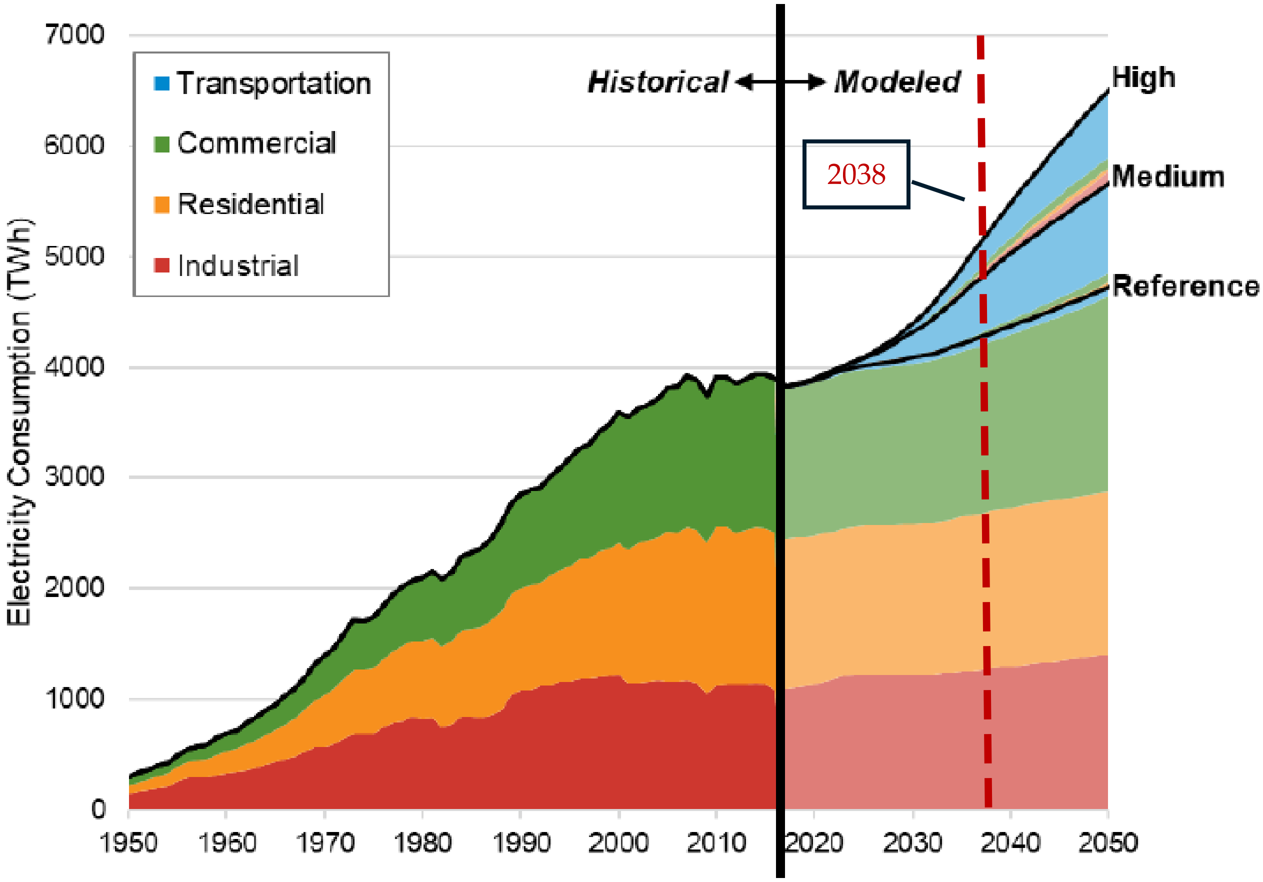


Figure 2 shows that until recently, electricity consumption by the transportation sector was negligible. With increased electrification, however, accelerated growth is looming (as Figure 3 shows). [1] Most of that growth will come from the transportation sector. Structural (building) electrification will lead to more-limited incremental growth in annual electricity consumption in part because of greater device efficiencies, like the high efficiency of heat pumps and their partial displacement of inefficient electric resistance heaters.

Figure 3: Historic and Projected Annual Electricity Consumption [1]



The "Reference", "Medium", and "High" labels in Figure 3 refer to NREL consumer adoption scenarios which will be discussed later in this report. The 2038 study horizon for the Scenarios Assessment is shown by the red dashed line. The 2038 Scenario Assessments are intended to create a better understanding of the effects that consumer adoption of new service options (consumer choice) will have on the reliability of the Western Interconnection and the extent to which policy and market forces may influence such trends.

Key Findings

- Load Growth
    - Most of the potential electrification growth will likely come from the transportation sector as the transition to vehicle electrification continues to accelerate. The transportation sector currently accounts for less than 1% of electricity demand but accounts for nearly 30% of total energy consumption in the U.S. [1] Widespread adoption of electric vehicles (EV) would have a monumental impact on the Western Interconnection and lead to its transformation.

- Most of the electrification load growth is concentrated around evening peak demand periods, usually around 7:00 p.m., and lead to more exaggerated diurnal load demand shapes. This is considered to create higher risks of unserved load and greater dependence on resource flexibility.

- Electrification: The Devil in the Details
  - The growth of EVs may be viewed as a potential problem or as a potential solution to address surplus solar PV/low load demand periods and could function as a source of storage at evening peak demand. With displacements of baseload resources (primarily coal fired) and increased penetrations of variable generation (primarily solar PV and wind), increases to diurnal evening peak demands from electrification increases operational challenges and risks to the operation of the bulk power system (BPS). If, however, distributed EV (DER-EV) infrastructure were strategically designed with time-of-use considerations in mind, the diurnal load demand shapes could be smoothed to shift load demand from evening peak to those times when energy production from solar PV is at its highest.
  - To the extent that it was modeled in the study, dispatchable DER-EV proved to be highly effective at mitigating unserved load. While DER-EV amounted to less than 2% of total annual energy production of the portfolio, DER-EV proved to reduce the occurrence of unserved load by as much as 50%.
- Resource Portfolio Mix
  - Dependence on natural gas-fired generation for energy production and resource flexibility, in the absence of other flexible resource types, is projected to continue with displacements of baseload resources (primarily coal fired) and increases in variable generation (primarily wind and solar).
  - Electrical storage was heavily dispatched for resource flexibility by the PCM simulation tool during evening peaks and was highly effective at reducing the instances of unserved load.
  - The results of the studies highlight the potential benefits that electrical storage offers especially in terms of balancing the operational challenges that rooftop solar PV presents to resource flexibility. Operationally, charging electrical storage when energy production from solar is high would reduce the risk of energy spillage, while dispatch of electrical storage at evening peak demand would reduce the risk of unserved load.
- Challenges of Solar
  - While annual energy production from solar averaged roughly 12% of the total resource portfolio energy production across all the simulations, the dispatch from solar at evening peak demand when unserved load occurred averaged less than 1% of the total resource portfolio dispatch. Ways to improve coordinated operation of electrical storage

    with that of solar should be developed. Increased dispatch capacity from electrical storage at evening peak would help to avoid the risk of unserved energy while charging electrical storage when energy production from solar is at its highest would help to avoid spillage from excess energy production.
    - Spillage of excess energy production occurs when load demand is low and energy production from wind and solar is high, leading to operational challenges and the commitment of resources.
- Demand-Side Management
    - Demand-side management appears to be beneficial as a mitigation strategy to smooth diurnal demand shapes and mitigate energy spillage by moving demand from high demand peak periods to low demand periods. Demand-side management of EV charging looks to be highly effective, followed by commercial and residential energy management strategies. Industrial demand-side management methods are well developed, so the potential for incremental improvements in demand-side management from the industrial sector is much lower than that from the transportation, commercial, and residential sectors.
    - EV infrastructure that incorporates time of use mechanisms shows great promise to smooth demand variations and better use renewable, intermittent resources.
- Transmission Use
    - Transmission path use increased in the Basin, Rocky Mountain, and Southwest regions with increasing surpluses of energy production in the Southwest and Basin regions and deficits in energy production from the Rocky Mountain region, due to displacements of baseload resources (primarily coal fired).
    - Transmission path use into California continues to be high from both the Northwest and the Southwest.
- Model Limitations
    - Consumer choice models need to be further investigated and refined beyond the fuel/energy source switching transitions captured in this assessment, to better identify likely electrification futures and to better forecast the implications to the reliability of the Western Interconnection. NREL identified this as a limitation in its EFS study and the limitation applies to the scenario studies. For more on this limitation, see the NREL EFS study. [1]
    - With DER technology gains, a better forecast of how DER will continue to develop is also needed.

2. Table of Contents

3. Introduction

This assessment investigates and analyzes potential risks to the reliability of the Western Interconnection associated with each of four potential futures developed by the WECC Scenario Development Subcommittee (SDS). WECC and its stakeholders developed the four future scenarios for the Western Interconnection based on a "focus question" developed during a scenario development workshop held March 27-28, 2018 at WECC's headquarters in Salt Lake City, Utah.

> *How might customer demand for electric services in the Western Interconnection evolve as new technologies and policies create more market options, and with that, what risks and opportunities may emerge for the power industry in sustaining electric reliability?*

From this focus question, the group created the Scenario Matrix with four themes for study:

Scenario 1 (SC1): Open Markets with Limited Customer Choice

Scenario 2 (SC2): Open Markets with High Levels of Customer Choice

Scenario 3 (SC3): Reliability and Cost Policy Driven with Restricted Customer Choice

Scenario 4 (SC4): Reliability and Cost Policy Driven with High Levels of Customer Choice

Scenario narratives for each theme were then created and study approaches defined for the narratives that identify tools, models, methods, and metrics to be used in each analysis.

In addition to the Scenarios, a WECC 2038 Reference Case was derived from the WECC 2028 ADS PCM P2V2.0 (2028 ADS PCM) by extending the load profiles of the 2028 ADS PCM another ten years to 2038. The Reference Case was created to serve as a comparative basis in the analyses.

In addition to the Scenario Matrix themes, other key drivers that were considered in the analysis included:

1. Changes in state and provincial electric energy market policies
2. Changes in federal electric energy market policies
3. Evolution of customer-side energy supply technology and service options
4. Changes in the character and shape of customer demand for electric power
5. Changes in utility-scale power supply options
6. Changes in state, provincial, and federal electric system regulations for reliability
7. Evolution of climate change and environmental considerations in relation to electric power service
8. Evolution of fuel markets in the electric power sector
9. Shifts in the cost of capital and financial markets
10. Economic growth within the Western Interconnection
11. Worldwide developments in the electric power industry

4. Scenario Design

Scenario Development Process

WECC uses scenario-based planning to manage uncertainty in long-term decision-making. It is useful to uncover possible risks to reliability and to develop strategies to reduce exposure to those risks. Scenarios offer a tool for imagining plausible futures, and planning for those futures. When used consistently and with proper detail, this approach can spur learning and help identify emerging risks and opportunities.

The scenarios examined in this report came from a workshop meant to help SDS members and stakeholders gather ideas, facts, and suggestions for new long-term scenarios. Twenty-five people from WECC and its member organizations attended the workshop and the Quantum Planning Group, Inc. facilitated. The WECC 2038 Scenarios Reports was the result of this workshop. [12]

This report uses the same scenarios and their results to define a scope of change that could occur in the Western Interconnection. The scenario narratives were used to select important modeling inputs (such as the NREL Electrification data inputs) that fit each narrative. This process, connecting qualitative description with quantitative measures, uses modeling and scenarios as informative tools to manage uncertainty and better understand plausible energy futures. In this way, as underlying data and modeling capabilities improve over time, more scenario-based analysis can provide longer-term opportunities for learning, and better equip WECC to assess system reliability from data refinements and other lessons learned.

Focus Question

Scenario planning allows stakeholders to create and test responses in a wide range of combinations of plausible future conditions. Useful scenarios are based on a clear sense of the issues at hand: the "focus question." Leading up to and during the scenario development workshop, the SDS agreed on the focus question detailed in Table 1.

Table 1: WECC 2038 Scenarios Focus Question

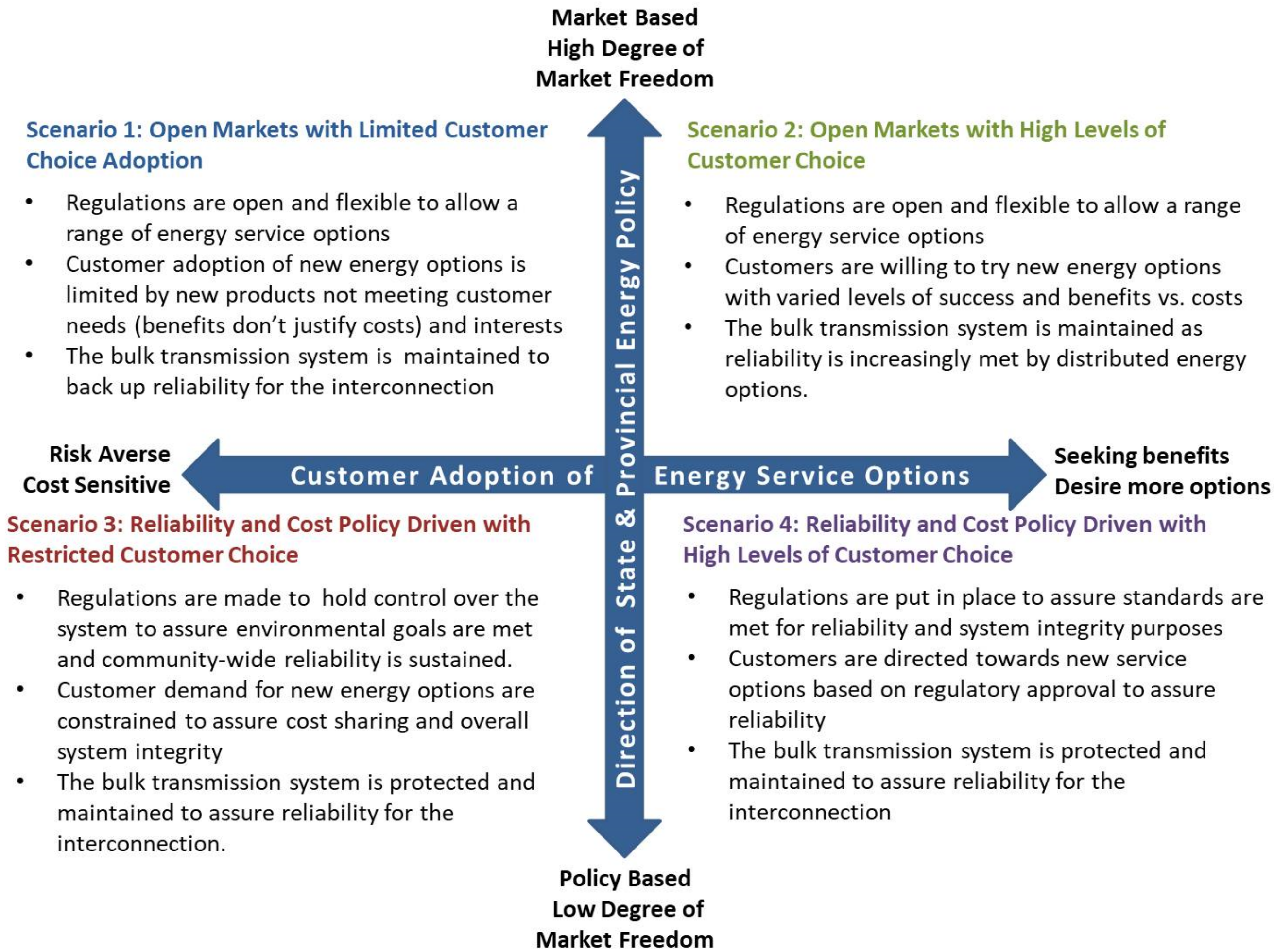
How might customer demand	How do we define customers, in what segments or categories? With DER? Grid connected?
for electric services	What services beyond commodity supply of electricity? What kinds of enhanced services?
in the Western Interconnection evolve as new technologies	Technology innovation that affects distributed energy as well as utility scale supply and delivery systems.
and policies	Policies at all levels.
create more market options, and with that,	Markets: regulated and unregulated. Options: Power supplies.
what risks and opportunities may emerge for the power industry	Who and what players will be in it?
in sustaining electric reliability?	What risks to the reliability of the BPS in the Western Interconnection? What standards and requirements apply?

Scenario Matrix

While scenario analysis does not allow accurate predictions of the future, it does provide a way to investigate and better understand plausible futures in which important decisions may play out. Useful scenarios derive these imagined futures from a studied consideration of factors and trends — key drivers — that will most likely influence future conditions. These key drivers are discussed in greater detail in the Assessment Approach section, and in Appendix D.

From this list of drivers, the SDS created a scenario matrix. A scenario-matrix helps organize and distinguish ideas when creating sets of future conditions. To create the matrix, the SDS prioritized the key drivers by consensus with two chosen as the most uncertain and most important. The SDS also selected these two drivers to be independent of one another. A range of uncertainty was then assigned to these two drivers, depicted as arrows with ends pointing in opposite directions to indicate polar opposites. Crossing these arrows creates two axes and four quadrants that function as "scaffolding" for developing scenarios as shown in Figure 4.

Figure 4: WECC 2038 Scenarios Matrix [12]



WECC Event/Pattern/Structure Trend Analysis System

The key drivers are organized and tracked in the WECC Event/Pattern/Structure (EPS) System. [10] The EPS tracking system is a tool to identify, organize, and analyze current events with respect to event relationships and overlaps, and to catalogue trends in the Western Interconnection and in the WECC scenarios. The basic parts of the method include:

Event Level - What happened or what did you observe?

Pattern Level - What pattern or trend is indicated?

Structure Level - What might be driving this on a core or structure level?

A set of early indicators were created for each scenario as a way to show movement toward or away from a scenario. Any EPS can then be related to one or more scenarios, key drivers, and early indicators. This system is designed to give broad context with rich content for continual learning and updating across the scenarios and drivers.

In addition, these EPS submissions are compiled, on a quarterly basis into a trends report that is posted on the WECC Scenario Planning Trends Reports portal. [11] Together, the WECC EPS tracking system and trend reports informs the scenarios development process and interested stakeholders of events that may be shaping the energy future of the Western Interconnection. Information from WECC's EPS system can give context and a deeper understanding of the issues addressed in this report and help in assessing results and future work.

5. Assessment Approach

The WECC Scenarios Task Force (WSTF) was formed to review and provide guidance to WECC staff throughout the Scenarios Assessment process; that effort included establishing the study approach, reviewing relevant modeling metrics, results, analysis, and drafting this assessment report. [15] This section of the report is meant to provide a high-level description of the study approach. Appendix D describes the assessment approach in greater detail.

Tools, Models, Methods, Data

Tools and models used to perform this study included:

- GridView tool used for production cost model (PCM) analysis.
- WECC Generation Capital Cost Tool for capital expansion analysis. [8]
- PowerWorld tool used for power flow analysis and the construction of the PCM model and to perform data validations.
- Various productivity tools to create model inputs, parse results, and create charts and tables.
- The NREL Electrification Futures Study, Demand-Side Scenarios, and Standard Scenarios. [1]

The 2028 ADS PCM was the foundation upon which the 2038 Scenario Cases and the Reference Case were built. Assumptions that went into the construction of the 2028 ADS PCM (e.g., transmission path constraints, planned generation) also apply to the 2038 study cases unless otherwise superseded by requirements of the Scenarios and Reference Case (e.g., candidate resource additions, load growth).

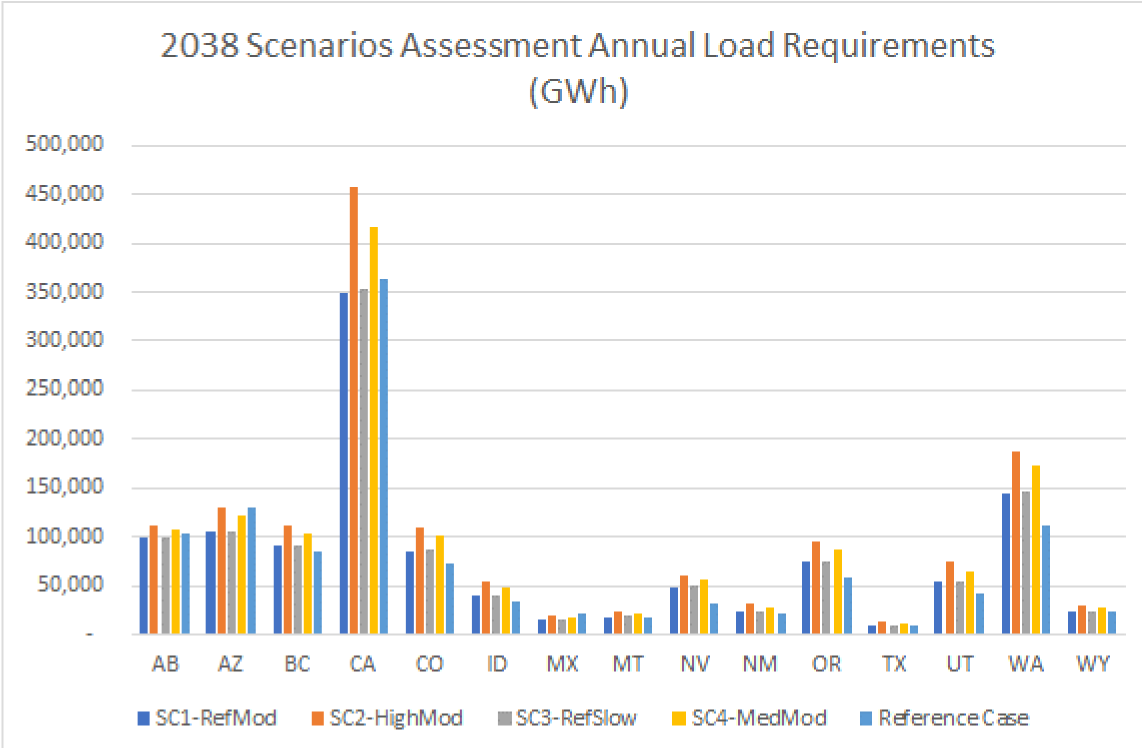
The load demand profiles and resource additions were derived from the 2028 ADS PCM and from the NREL EFS and Standard Scenarios. The underlying tools, models, methods, and data used by NREL to produce the models used in this assessment will be discussed briefly in this report.

More details can be found in Appendix D.

Load

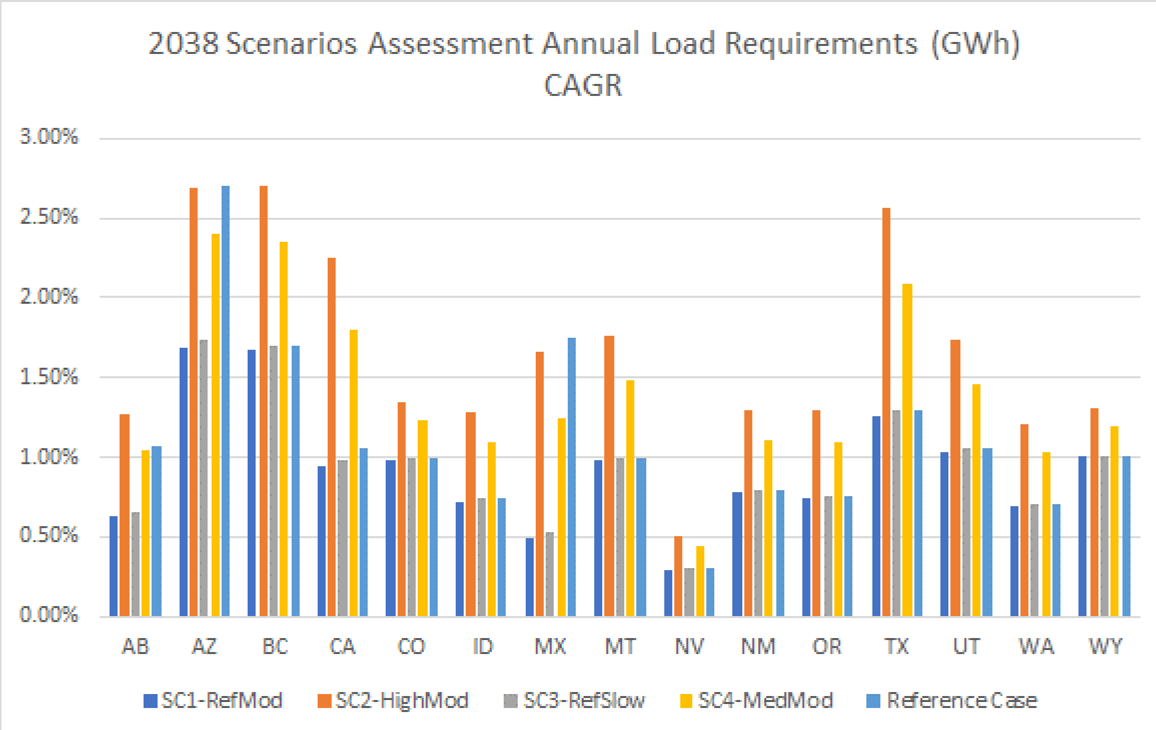
Annual load energy requirements by state and province for the Scenarios and the Reference Case are shown in Figure 5.

Figure 5: 2038 Scenarios Assessment Annual Load Requirements (GWh)



The Reference Case load profiles were constructed by extending the load profiles of the 2028 ADS PCM another 10 years using compound annual growth rates (CAGR) taken from integrated resource plans published by several balancing authorities in the Western Interconnection as shown in Figure 6. As Figure 5 shows, load requirements for SC1 and SC3 are like those of the Reference Case, but the load requirements for SC2 and SC4 are much higher due to assumed higher customer adoption of new electricity service options.

Figure 6: 2038 Scenarios Assessment Annual Load Requirements (GWh) CAGR



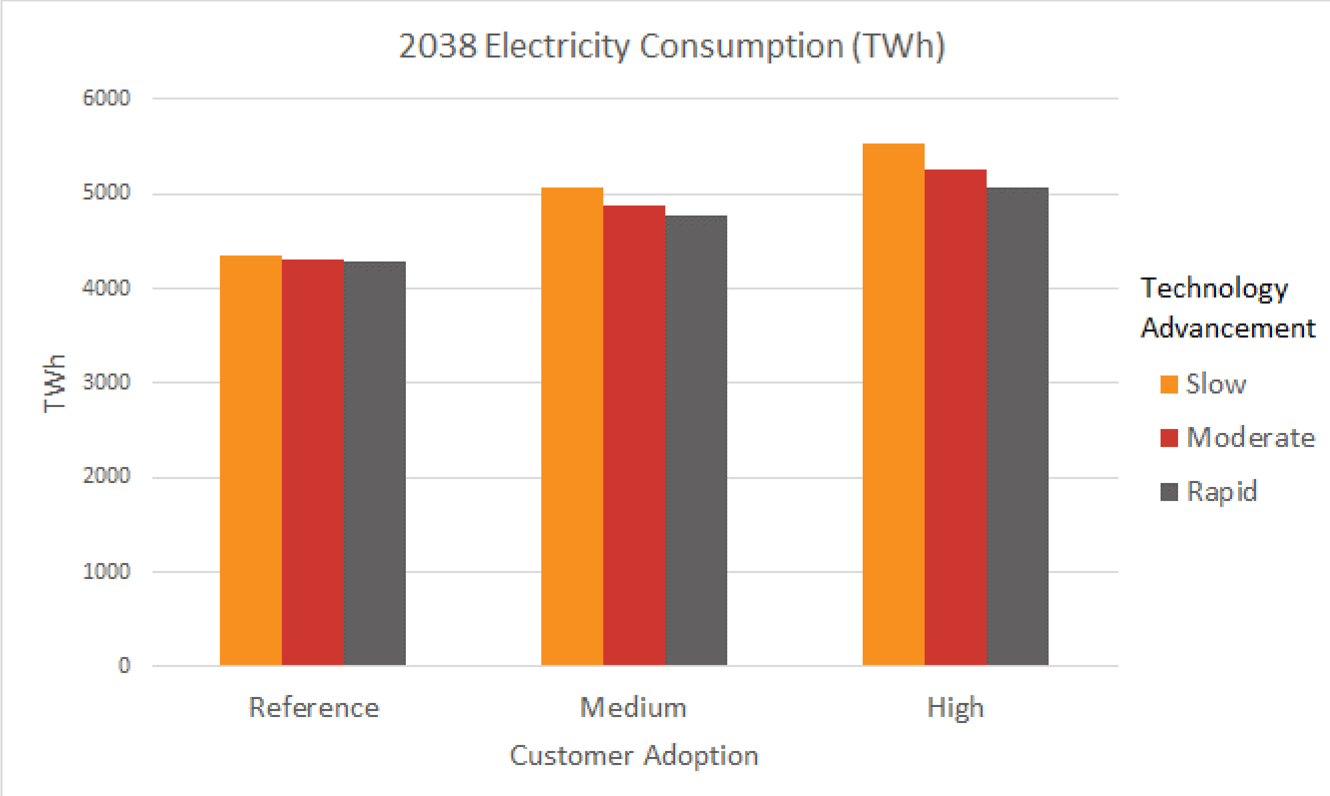
The four scenarios shown in the Scenario Matrix define different loads to be served, based on the drivers defined by the Scenario Matrix. To create these distinct load profiles, it was necessary to associate each with various levels of customer adoption of new service options. These were based on assumptions underlying the narratives for each scenario. To complete this step, WECC and the WSTF turned to NREL. NREL has defined a series of potential future load profiles, called the Demand-Side Scenarios, as part of the Electrifications Futures Study (EFS). [1] These demand-side scenarios are based on the rate of future technology advancement and the rate of customer adoption of new technologies. From these nine demand-side scenarios, the WSTF selected four that most closely aligned to the narratives for each of the scenarios shown in Table 2.

Table 2: NREL Demand-Side Scenarios Matrix [1]

	Slow Technology Advancement	Moderate Technology Advancement	Rapid Technology Advancement
Reference Customer Adoption	Reference Adoption, Slow Technology Advancem SC3	Reference Adoption, Moderate Technology Advancem SC1	Reference Adoption, Rapid Technology Advancement
Medium Customer Adoption	Medium Adoption, Slow Technology Advancement	**Medium Adoption, Moderate Technology Advancem** SC4	Medium Adoption, Rapid Technology Advancement
High Customer Adoption	High Adoption, Slow Technology Advancement	High Adoption, Moderate Technology Advancem SC2	High Adoption, Rapid Technology Advancement

The load requirements for the Demand-Side Scenarios appear to be more sensitive to assumptions about customer adoption of new service options than about technology advancement shown in Figure 7.

Figure 7: NREL Demand-Side Scenarios -- 2038 Adoption versus Tech Advancement [1]



The load requirements for each Demand-Side Scenario also appear to decrease with technology advancement due to improved efficiencies.

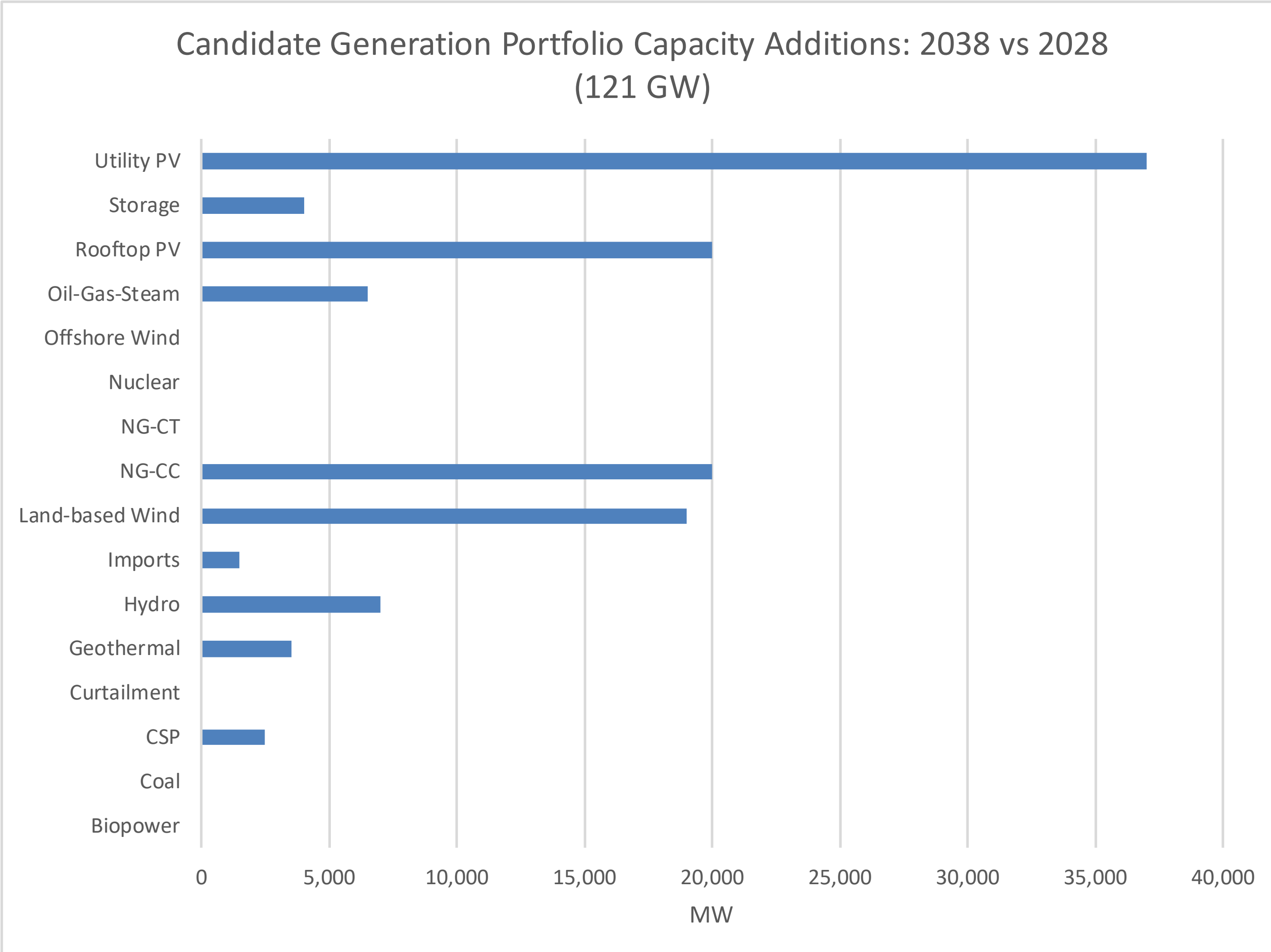
The hourly demand profiles shown for each Scenario are those of the Demand-Side Scenarios based on a bottoms-up approach and include flexible DER from EV.

More detail on NREL's bottoms up approach to construct the Demand-Side Scenarios can be found in Appendix D.

Generation Resources

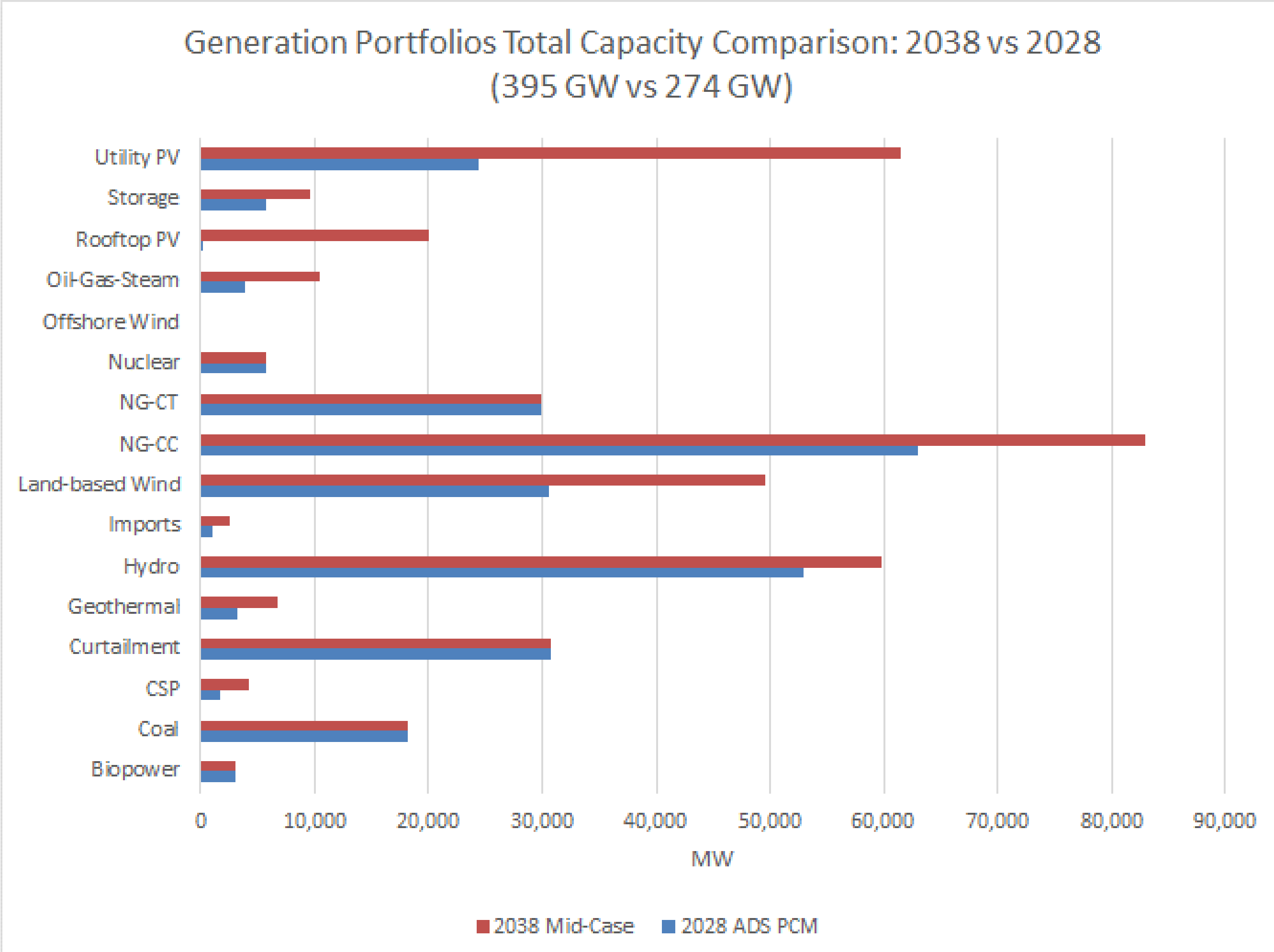
The generation resource model used in the 2038 scenarios was derived from the 2028 ADS PCM and augmented with new candidate resources derived from the NREL Mid-Case Standard Scenario shown in Figure 8. [5]

Figure 8: Reference Case Resource Additions to 2028 ADS PCM



A comparison of total resource capacities by resource type between the Reference Case and the 2028 ADS PCM is shown in Figure 9.

Figure 9: Total Generation Capacities Comparison – Reference Case vs 2028 ADS PCM



The construction of the generation resource portfolio used in the studies is the result of augmenting the 2028 ADS PCM with additional resource types so that the resulting resource mix matched the Mid-Case Resource Portfolio, which then yielded the 2038 Reference Case Candidate Resource Portfolio (RCCRP). The RCCRP includes potential energy resources that are available for commitment and dispatch in PCM simulations of the Reference Case.

The RCCRP was further augmented with hourly resources representing dispatchable distributed energy resources (DER) from electrical vehicles (DER-EV) to produce a candidate resource portfolio for each scenario (SCRP).

DER-EV is not the only representation of DER captured in the Reference Case and the Scenarios Cases. DER resources already modeled in the 2028 ADS PCM are also included. The types of DER that are captured in the model in some form are described in Table 3.

Table 3: Distributed Generation Modeled with the Scenarios Cases

Distributed Generation Modeled within the Scenarios Cases	
Nomenclature	**Descriptions**
BTM	**Behind-The-Meter**: A generating unit or multiple generating units at a single location (regardless of ownership), of any nameplate size, on the customer's side of the retail meter that serve all or part of the customer's retail load with electric energy. All electrical equipment from and including generation up to the metering point is behind the meter. This definition does not include BTM resources that are directly interconnected to the BPS.
DER	**Distributed Energy Resource**: Any generation resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the BPS.
DER-EV	**Distributed Energy Resource – Electric Vehicle**: DER, as described above, provided by Electric Vehicle Storage. Representative only of flexible load associated with the NREL Demand-Side Scenarios used to derive the load profiles modeled in the scenario PCM cases.
DG	**Distributed Generation**: Any non-BPS generating unit or multiple generating units at a single location owned and/or operated by 1) the distribution utility, or 2) a merchant entity.
DR	**Distributed Resource**: same as DER.
EE	**Energy Efficiency**: When modeled on the supply, represents an hourly resource that service as a proxy for load demand management (e.g., peak smoothing, increasing load factors)
Rooftop Solar PV	**Rooftop Solar PV**: Energy production provided by rooftop solar photo voltaic resources, either commercial or residential that is not connected directly to the BPS.
Storage ES	**Electrical Storage**: An energy storage device or multiple devices at a single location (regardless of ownership), on either the utility side or the customer's side of the retail meter. May be any of various technology types, including electric vehicle (EV) charging stations.

The nature of DER is expected to transform over the timeline identified in this report and, as such, future work is warranted to better understand how DER may evolve.

More detail can be found in Appendix D.

Transmission

The inter-regional transmission path assumptions in the 2028 ADS PCM are carried forward to the Reference Case and the Scenario Cases and are enforced as constraints. Since the focus of 20-year horizon studies is on inter-regional transmission paths, necessary reinforcements to intra-regional transmission (transmission not associated with a WECC interface path) are assumed and therefore not enforced as a constraint in the PCM. The inter-regional transmission paths are shown in Figure 10.

Figure 10: Western Interconnection Transmission Interface Paths [20]

More information on WECC Interface Paths is available in the WECC Path Rating Catalog. [20]

More details on the transmission modeling can be found in Appendix D.

Economics

Various economic metrics are used either as inputs or produced as results and include:

Locational Marginal Price (LMP): A way to represent the price of the next increment of wholesale electric energy at different locations required to respond to the next incremental change in load subject to physical constraints of the transmission system. LMP is the basis for the security constrained economic dispatch cost function modeled in PCMs. The units of LMP are expressed in $/MWh. LMPs have three components: energy, congestion, and loss. In the absence of congestion and losses, the LMPs at all nodes in a system will be equal to that at the reference point (e.g., System LMP or shadow price). Price spreads across transmission paths are due to losses and congestion. In nodal markets, there is usually a maximum value defined that an LMP at a node can incur. The maximum LMP is reached when unserved load occurs since the cost of unserved load as a last resort dispatch measure is so high.

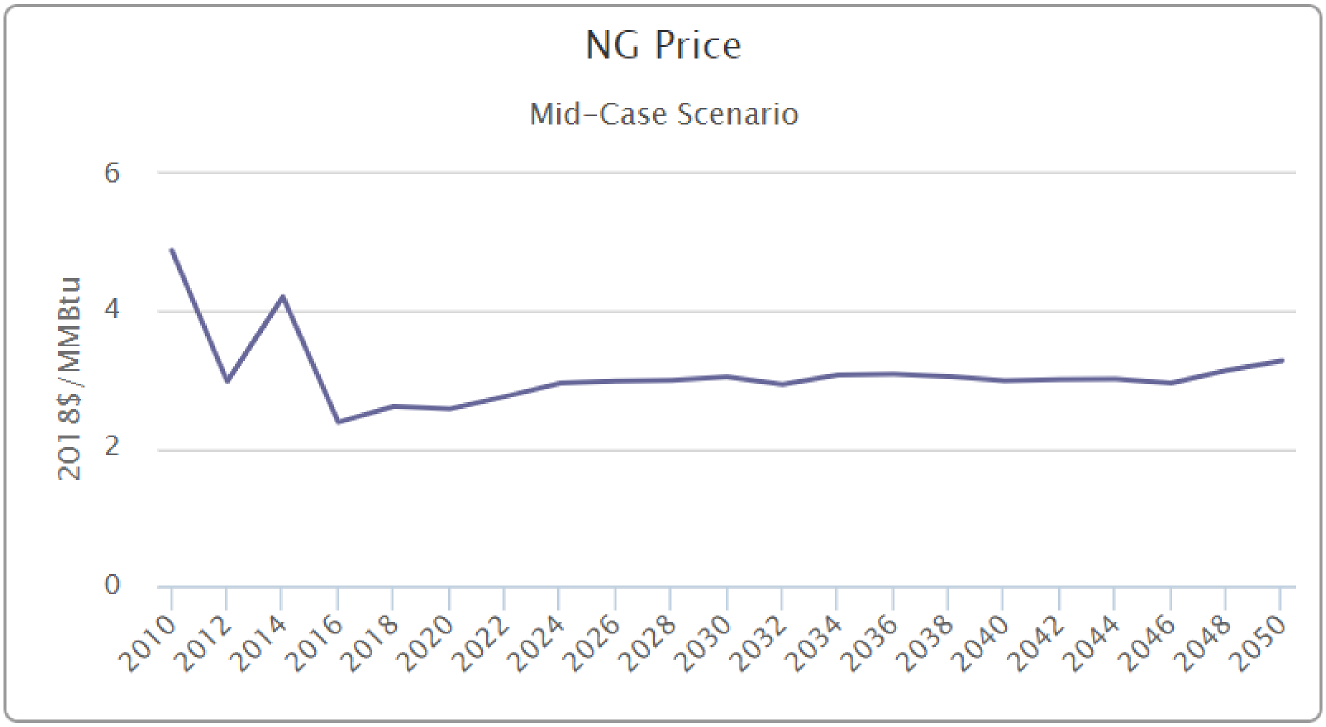
Levelized Cost of Energy (LCOE): A measure of the average net present cost of electricity generation for a generating plant over its lifetime. LCOE is the basis for the cost model in capital expansion (CapEx) tools. The LCOE is expressed in $/MWh. The LCOE is calculated as the ratio between all the discounted costs over the lifetime of a generation resource divided by a discounted sum of the actual energy amounts delivered. The LCOE is used to compare different methods of electricity generation on a consistent basis. The LCOE represents the average revenue per unit of electricity generated that would be required to recover the costs of building and operating a generating plant during an assumed financial life and duty cycle or capacity factor. Factors that go into the calculation of LCOE include investment cost, cost of capital, fuel costs, fixed and variable operations and maintenance costs, financing costs, and an assumed duty cycle or capacity factor.

Capital Expansion Cost (CapEx): The investment capital expenditures for equipment used to generate or deliver electricity. Expressed in units of $/kW, CapEx represents the total project engineering, procurement, and construction (EPC) cost. CapEx is sometimes referred to as overnight cost which is the cost of a construction project if no interest was incurred during construction, as if the project was completed "overnight." CapEx is an input of LCOE before the levelization of ongoing costs, taxes, and financing.

CO_2 Emissions Cost: The SDS considered and debated a wide variety of factors that contribute to the cost of carbon. [18] For the WECC Scenarios, the SDS agreed on a $55/ton CO_2 Emissions Cost. This value is a carryover from deliberations of the SDS on scenarios modeling metrics as part of the WECC 2016 - 2017 Study Program and largely based export consensus on the economics of climate change. [19]

Natural Gas Price:[1] The base price for natural gas (e.g., Henry Hub) modeled for the system in 2038 was 3.05 $/MMBtu, which came from the price used by NREL to produce the Mid-Case Resource Portfolio shown in Figure 11. [17]

Figure 11: Natural Gas Base Price for Mid-Case Resource Portfolio [17]



More details can be found in Appendix D.

Key Drivers

Most scenarios derive imagined futures from a studied consideration – key drivers – that are categorized to most likely and most powerfully influence future conditions. For the WECC Scenarios, the SDS agreed on the following initial set of key drivers:

1. Changes in state and provincial electric energy market policies,
2. Changes in federal electric energy market policies,
3. Evolution of customer-side energy supply technology and service options,
4. Changes in the character and shape of customer demand for electric power,
5. Changes in utility-scale power supply options,

[1] The study used the NREL Mid Case Natural Gas prices, based on the U.S. Energy Information Administration EIA) Natural Gas (NG) forecast from 2018. The EIA 2020 equivalent NG forecast, published in January 2020, has since increased prices in the 20-year time horizon.

6. Changes in state, provincial, and federal electric system regulations for reliability,
7. Climate change and environmental issues on electric power service,
8. Evolution of fuel markets in the electric power sector,
9. Shifts in the cost of capital and financial markets,
10. Economic growth in the Western Interconnection, and
11. Worldwide developments in the electric power industry.

The SDS prioritized this list and distilled the key thematic drivers of the Scenario Matrix. The thematic drivers form the axis of the Scenario Matrix shown in Figure 4 and discussed in the Scenario Design section under "Scenario Matrix". The thematic drivers are:

1. Direction of state and provincial energy policy.
2. Customer adoption of energy service options.

While the thematic drivers form the axis of the scenario-matrix, the remaining key drivers in the list are still used in the formulation of the scenario narratives and model construction. Modeling these key drivers is discussed in Appendix D under "Key Scenario Drivers".

Customer

The WECC Scenario Report considers indirectly consumed electricity to be an input for other valuable services and products and to affect diversity in consumer choice. Air conditioning and heating, lighting, energizing tools and equipment, refrigeration, and powering various modes of transportation are examples of customer choice drivers .

Customer choices related to indirectly consumed electricity are numerous, variable, and assumed in this study to be captured in the bottoms-up approach used by NREL to derive the demand-side load models that were used in the scenario studies.

Parsing Customer Segments

In considering the range of electric power customers, scenario development workshop members also considered how to best categorize electricity customers. SDS members anticipates that further analysis of this issue will be done as the scenario analysis process advances. SDS members distinguished customers by response to varying energy sector developments, like technology, regulatory, and shifts in consumer priorities. SDS members spent considerable time on this discussion in the Workshop and in a follow-up SDS meeting dedicated to defining customer segments.

Ultimately, each segment was defined so a customer could have a demand-side interaction with its electric service provider or not, and so the customer might have DERs to use or share with the electric service provider. Members thought consumer choices might vary widely in response to the different conditions in the scenarios. Customer responses could include high, moderate, low, or no use of new products and services in the industry where use was qualified by a set of determining factors. [16]

An example of a consumer segment breakdown taken from Scenario 2 is shown in Table 4 and allows comparisons among the scenarios. Table 4 is a template to help parse different customer segments and services for each Scenario.

Table 4: Scenario 2 Consumer Segment Breakdown

Customer Segment	Wholesale	Demand-Side management	Distributed Energy Resources	Local Micro-Grids	Self-Generation	Retail Choice	CCAs
Large commercial & industrial	Increase based on new or improved technology	High adoption and use	High adoption and use	Low	Moderate: High Use of Information Services	Moderate to Low	Not applicable
Small-medium C&I	Increase based on new or improved technology	High use and adoption	Moderate	Limited to local micro-grids	Low: Limited to Rooftop Solar	Limited	At current levels unless increased by customer demand, technology or policy
Residential Rural*	Not applicable	Limited as provided by the incumbent utility	Low: most served by the incumbent utility	Limited to low, may be served by local cooperatives	Limited to Rooftop Solar	Limited as provided by the incumbent utility	At current levels unless increased by customer demand, technology or policy
Residential Urban	Possible selling to local utility based on policy	High use and adoption	Low	High within CCA's and local micro-grids	Limited to rooftop solar	Moderate: Based on costs benefit analysis	At current levels unless increased by customer demand, technology or policy
Agricultural	Selling or buying to local utility or Co-op by	High use and adoption	Left to local Co-ops	Limited to Co-ops	Wind and rooftop solar	Left to local Co-ops	Not applicable

Customer Segment	Wholesale	Demand-Side manageme nt	Distributed Energy Resources	Local Micro-Grids	Self-Generation	Retail Choice	CCAs
	large agricultural companies						

The analyses in this report do not resolve the issue of how customer electric service markets may change over time; the scenarios suggest different possible developments. The consumer choice models in this study largely focus on end-use equipment that have the potential to transition from non-electric to electric technologies (e.g., electric vehicles, heat pumps). The lack of consumer choice modeling for all end uses is a shortcoming that requires more research, especially in terms of economic trade-offs between technologies, consumer preference and behavior, supply chain and infrastructure impacts, risk, financing, and integrated challenges and opportunities across technology portfolios. [1] NREL has identified this shortcoming in the EFS and continues work to refine consumer choice models as does WECC.

Policy and Energy Markets

One of the key thematic drivers focuses on the direction of state and provincial energy policy. Federal policy was also considered in the analysis, although the SDS considered state and provincial policies to be more influential on the future of the Western Interconnection.

State and Provincial Policy and Energy Markets

Fourteen Western states, two Canadian provinces, and Northern Baja California make up the geographical footprint of the Western Interconnection. These jurisdictions set policies and rates that directly affect how electricity markets function in their footprints. They also have regional influence. Specifically, rules that govern markets (in conjunction with federal regulations) in places like California and Alberta where formal markets are in use to procure imbalance energy and ancillary services are considered influential. Also viewed as significant are policies on cost recovery for plant investment in utility rates, renewable portfolio standards, climate change, rules governing the use of local distribution systems, and much more. Policy focus areas may include:

- Rules and policies that affect states and provinces abilities to expand their energy products and energy services markets.
- The emergence of new regional transmission organizations (RTOs) that can manage system reliability.
- Renewable portfolio standards and climate change mitigation policies established by states or provinces.

- Cost recovery regulations related to power sales from DER.
- Rules or regulations that affect the price of power in wholesale energy markets.
- Rules and regulations that change as technological innovations allow for new energy products and services options.

Table 5 shows the interrelationship between state and provincial policies for Scenario 2.

- **Table 5: Scenario 2 State/Provincial Category and Forms of Oversight**

Policy Area	Statewide Oversight	Local: County/City Oversight	Scenario 2
Electric Rates, Prices and Revenue	State/Provincial PUCs	Municipal utilities and community aggregation	State/Provincial struggle with old regulations protecting traditional utilities but eventually allow for cost recovery of the bulk system and DER investment
Renewable Portfolio Standards and Climate	State/Provincial Laws and PUCs	For municipal utilities and community aggregation	Initially states/provinces maintain existing RPS and other environmental regulations, and by the end years, most allow regulations to fall away as the grid is over 90% clean powered.
Air Quality, Water and Land Use	State/Provincial Laws, Commissions and Agencies	City and County departments and agencies	Water pollution and other environmental regulations continue and are tightened. Land use regulations are modified to encourage and allow for local distribution needs and micro-grids
Capital/Resource Investment Planning Approval	State/Provincial Laws, ISOs, Commissions and Agencies	Municipal utilities and community aggregation	Laws and approval systems are modified to encourage investment in DER, self-generation, micro-grids Cities and community groups create financing instruments for CCA's
Operating standards, equipment and Safety	State/Provincial approved Industry Assoc.	State & local oversight in areas like fire codes, building codes	Rules continue to encourage energy efficiency, and demand-response, and in some areas even mandate those.
Consumer Protection and Product Quality	State/Provincial Laws and State/Provincial Approved Industry Associations	Generally, not applicable	States/Provinces and local entities slow to realize the extent of consumer protection required under this new paradigm. In later years problems are

Policy Area	Statewide Oversight	Local: County/City Oversight	Scenario 2
			addressed

Federal Electrical Policy and Markets

The US, Canadian, and Mexican governments set policies that affect electric energy markets both within those boundaries and, increasingly, on an expanding regional basis. Federal policies carried out by FERC, NERC, DOE, EPA, and other agencies that oversee nuclear power, oil/gas and coal development, as well as environmental standards can substantially influence electricity market shifts and electric service delivery. Consumer protection, tax, and other laws can also influence the evolution and nature of electric customer demand. The structure of this driver may include:

- Federal rules and regulations that affect cost recovery and electric rates for all generation, transmission, or other power industry plant assets;
- Federal policies and regulations that affect fuels such as coal, natural gas, or nuclear materials used for electric generation; and
- Federal regulations or policies addressing environmental issues (air, water, land use) that can affect any aspect of the power industry (e.g., investments, operations).

Each scenario narrative includes an analysis of how the state, provincial and federal policies intersect/overlap in that set of conditions. While acknowledging that the ability to assess the potential impacts of the wide range of state and federal policy options and confidence in projecting how those might play out in the future is limited, policy conditions were nevertheless embedded in key inputs. For example, the Mid-Case Resource Portfolio captured key policies such as renewable portfolio standards. The report also suggests future work worthy of consideration and highlights results considered informative for future policy development.

Limitations

- Models are not absolute and predictive. There are always gaps. In this way, the study results discussed in this report are not meant to be taken as a prediction of the future. Instead, the goal of the Scenario studies is to better understand the energy future through a range of plausibility. In this task, it was considered important to avoid:
  - The illusion of certainty.
  - Overconfidence in models.
  - Over confidence in results.
- The scenario exercises completed were limited to one single generation ensembles and five load ensembles. A guiding principle of scenario planning is that of continual learning. In this regard, future work to build upon this study should include studies utilizing different load and

generation ensembles based upon lessons learned from this study in terms of drivers and assumptions.

- The economic analysis performed in this effort incorporated widely known and accepted quantitative model limitations. The process generally assumed the models useful for predicting future outcomes over short periods of time, due to limited impacts from external events and the greater predictive power of a small set of key variables. Over longer time periods, such through 2038, external events are presumed to have greater potential impacts, reducing the value of key factors. In this context, quantitative modeling can illuminate aspects of interrelationships, trends, directions of influence, and larger scale results. Scenario modeling also endeavors to match qualitative developments with related quantitative variables; thus, it is an inherently imperfect process, open to change and rethinking. This report is accordingly limited, but nevertheless provides insights resulting from the exercise.
- Consumer choice models were based on the work of NREL as part of the Electrification Futures Study (EFS). [5] The consumer choice models in this study do not include all possible end-use technologies, known or unknown. The caveats and limitations that NREL acknowledges, in this regard, also extend to those of the 2038 Scenarios Study. The consumer choice models at issue prioritized end-uses of what could be classified as energy transition electrification with electrification defined as the substitution of electricity for direct combustion of non-electricity-based fuels (e.g., gasoline and natural gas) used to provide similar services. This fuel switching-based definition includes any potential growth in the service driven by population or economic change but excludes new or emerging energy services driven by technological or economic change, such as indoor agriculture, new plug loads, and expansion of data centers. As a result, the consumer choice model emphasizes electric technologies that can be used to replace non-electric devices/systems, such as replacing internal combustion style vehicles with electric, heat pumps for natural gas space heating, and electric induction furnaces for fuel-fired industrial furnaces. The consumer choice model incorporated here does not include yet to-be-developed electric-based technologies. [5]
- The resource portfolio created for the scenario studies was derived from the Mid-Case Resource Portfolio augmented with dispatch DER from vehicle electrification that came from the NREL Demand-Side Scenarios. The Mid-Case Resource Portfolio is intended to represent a reference portfolio based on policies in place as of July 31, 2019 and to also include other default assumptions derived from the NREL's annual technology baseline. [6] The Mid-Case Resource Portfolio represents a reference portfolio of candidate resources presented to the PCM for commitment and dispatch and provides a useful baseline for comparing scenarios and evaluating trends. While the resulting portfolio of candidate resources provides a good starting point to answer some of the questions posed by the Scenarios, a single portfolio does not adequately capture a full range of plausible energy futures.

6. Results and Observations

The Western Interconnection is undergoing transformational change and there is a great deal of uncertainty surrounding its energy future. Considering this uncertainty, the goal of Scenario Planning is not to predict the future, but to gain a better understanding of plausible futures and underlying drivers. A guiding principle behind the WECC 2038 Scenarios Assessments is to illuminate how underlying drivers may influence the energy future of the Western Interconnection. The scenario assessments are not meant to be comprehensive, but rather a learning process that can be built upon with supplemental study.

Successful scenario planning must pose pertinent and pivotal questions. In this regard, there are questions that we know we can answer, there are questions that we know we can't answer, and there are questions yet to be formed. This was the approach taken for this report effort.

Reference Case (RC)

Reliability planning at WECC comprises three study horizons:

Near term (1 to 5 years): focused on power flow, stability, situational awareness, event analysis.

Planned (5 to 10 years): focused on resource adequacy, system use, and potential reliability risks to the planned Western Interconnection.

Long Term (10 to 20 years): focused on plausible energy futures, the drivers that may influence that future, and the risks to reliability that may arise.

Understanding the best path to analyze a study horizon is essential to gaining a better understanding of reliability risks. Establishing continuity between study horizons provides traceability, context, and a frame of reference. In this regard, the Planned 2028 ADS PCM is the launching point for the 2038 Reference Case. The 2038 Reference Case provides traceability back to the 2028 ADS PCM and serves as a reference point that can be used to compare Scenario results.

A 2038 Reference Case (Reference Case) was created by extending the area load trajectories of the 2028 ADS PCM another ten years and is meant to represent a "business-as-usual" case for 2038, and represents a future in which the electric industry in the Western Interconnection is in a steady state with extension of current end-use patterns, policies, and market conditions. The Reference Case serves as a basis to compare scenarios in the analysis as policies and market conditions in each scenario vary from those of today. The 2028 ADS PCM was augmented with additional resources to achieve a resource mix equivalent to that of the Mid-Case Resource Portfolio. [5]

RC: Modeling Components

Load Models: That extended from the 2028 ADS PCM using the CAGRs of the 2028 ADS PCM as further described in Appendix D under "Load Models".

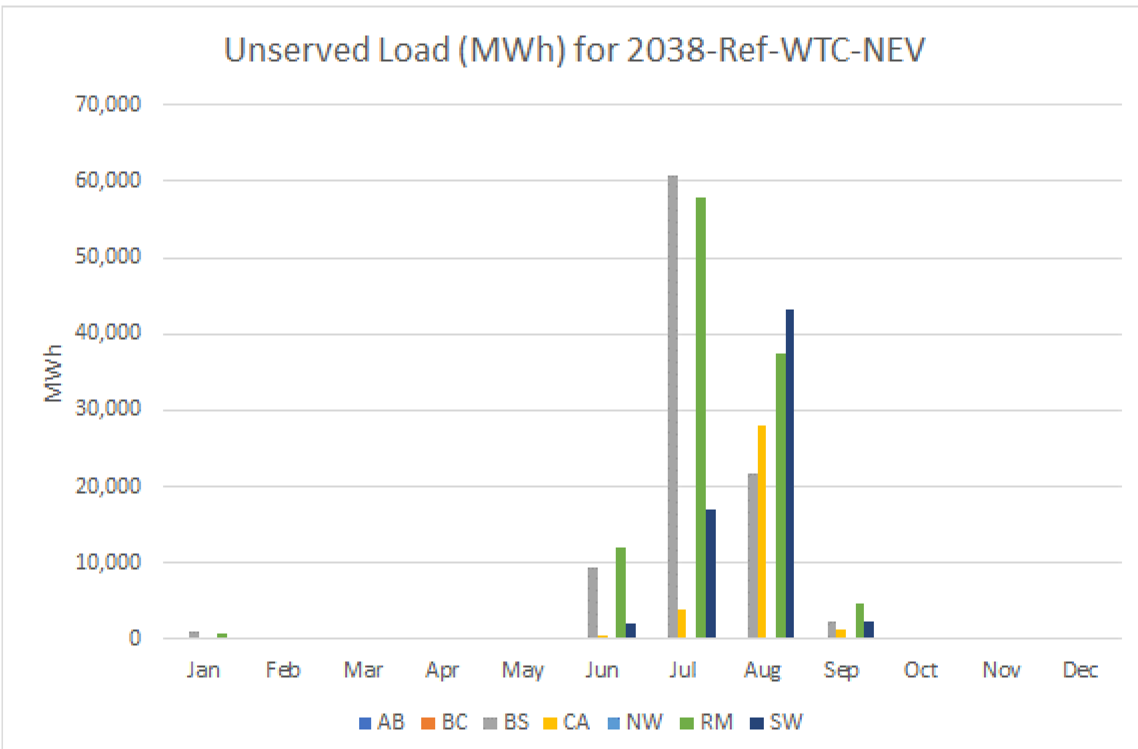
Generation Resource Portfolio: The 2038 Reference Case Candidate Resource Portfolio (RCCRP) as further described in the Assessment Approach section.

Transmission Topology: The transmission topology is that contained within the 2028 ADS PCM with interface paths monitored as further described in Appendix D under "Transmission Models."

RC: Load

Figure 12 shows unserved load in the Reference Case as 306 GWh.

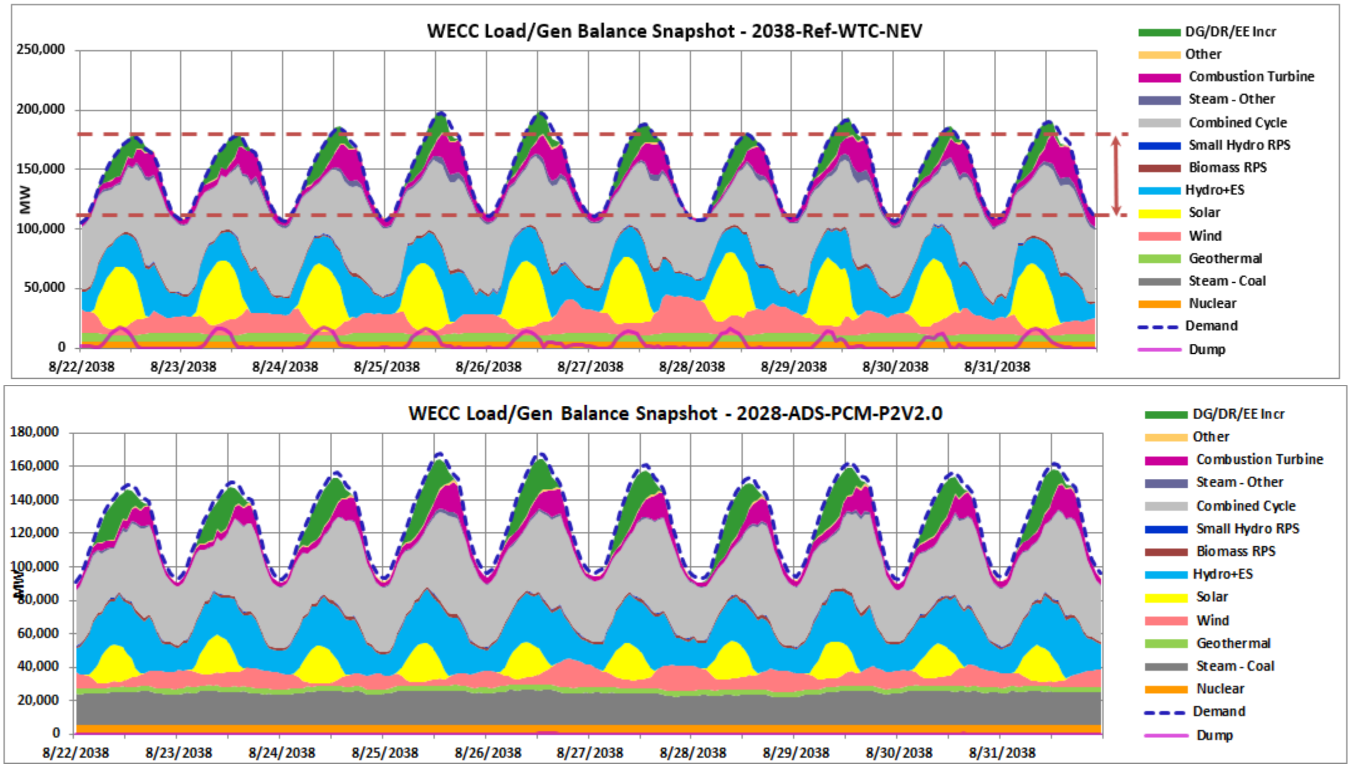
Figure 12: Unserved Load for 2038 Reference Case WTC NEV



The bulk of the unserved load shown in Figure 12 occurs primarily in the Basin, Rocky Mountain, and Southwest regions of the Western Interconnection. Transmission path use is also heavy in these regions.

The load and generation balance for a ten-day period where unserved load occurs in the 2038 Reference Case in comparison to that of the 2028 ADS PCM is shown in Figure 13.

Figure 13: Comparison of Load/Gen Balance - 2038 Reference Case to 2028 ADS PCM



The diurnal load shapes between the 2038 Reference Case and the 2028 ADS PCM are similar since the load model for the 2038 Reference Case was derived from the 2028 ADS PCM by applying the CAGRs of area loads in the 2028 ADS PCM to extrapolate the load model out another ten years. The area load CAGRs used were obtained from integrated resource plans of regional planning authorities. For the ten-days shown, the evening peak demand of the 2038 Reference Case is approximately 200,000 MW as compared to an evening peak demand of approximately 168,000 MW in the 2028 ADS PCM; this corresponds to a net system CAGR of approximately 1.76%.

Unserved load occurred in the 2038 Reference Case, while no unserved load occurred in the 2028 ADS PCM. This can be explained by higher demand in the 2038 Reference Case and a higher concentration of solar generation in the commitment and dispatch of resources.

During this 10 day period, an envelope exists between demand peaks and valleys, as shown by the horizontal red dashed lines in Figure 13, where unserved load results when the evening peaks exceed the upper bound of this envelope. The values of the envelope bounds are especially sensitive to the extent of variable generation (e.g., solar and wind) relative to the extent of effective load carrying capability (ELCC) and resource flexibility at evening peak (e.g., gas fired and electrical storage).

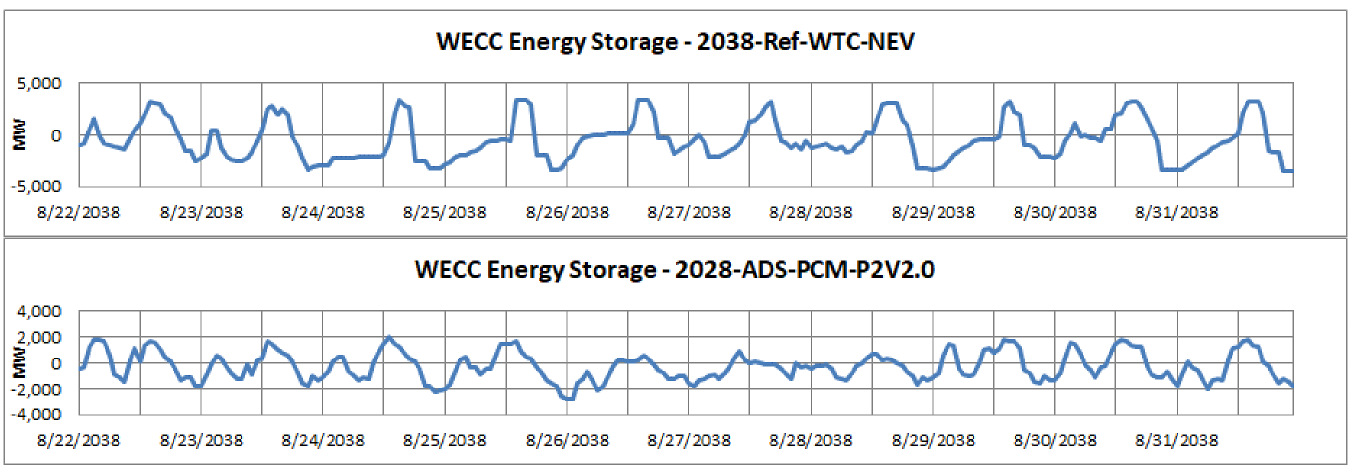
Unserved load occurs after the energy supply from solar drops off abruptly. The unserved load occurs on the downward slope following evening peak demand. As dispatch from solar resources decreases, the dependence on resource flexibility (such as electrical storage) increases.

While energy supply from DG/DR/EE (modeled on the supply-side) increases with demand to evening peak it soon drops off quickly once the evening peak demand has been reached which is when instances of unserved load occur. This can largely be attributed to the depletion of electrical supply from electrical storage after reaching evening peak demand.

There is more solar in the resource dispatch for the Reference Case than that for the 2028 ADS PCM, increasing the instances of energy spillage when energy production from solar is high and load demand is low. Combining solar generation with storage to form hybrid systems would greatly reduce the operational challenges that dispatch from solar alone creates; this could be promoted by policy and market mechanisms, as well as technology advancements.

A comparison of the diurnal shapes of electrical storage between the 2038 Reference Case and the 2028 ADS PCM is shown in Figure 14.

Figure 14: Comparison of Electrical Storage - 2038 Reference Case to 2028 ADS PCM



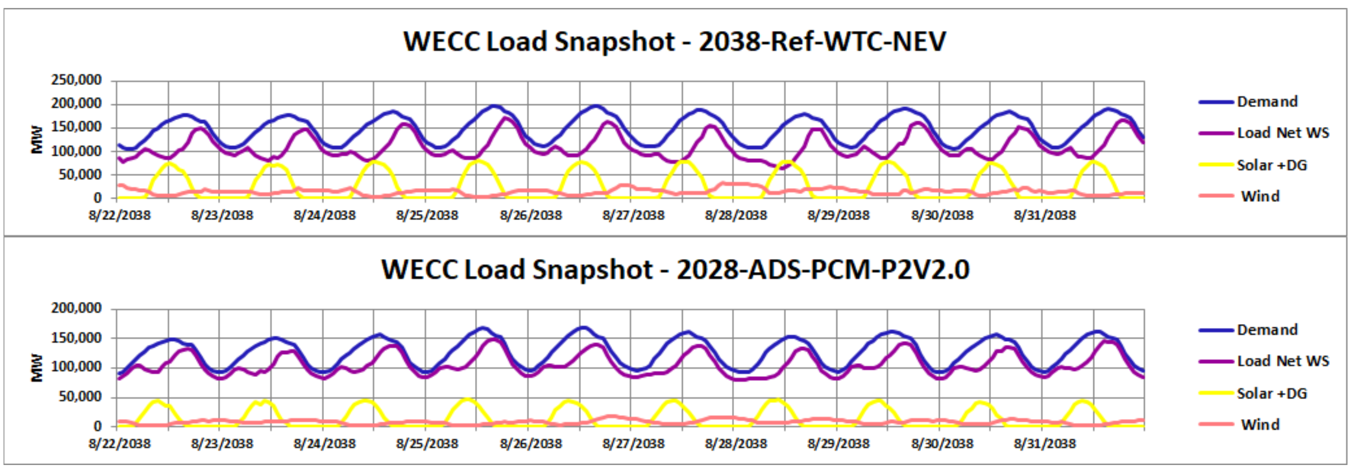
The diurnal commitment and dispatch shape of electrical storage in the Reference Case is more uniformly repeated and pronounced at evening peak demand than what results for the 2028 ADS PCM simulation. In general, the charging and dispatch pattern for electrical storage will be more uniformly repeated and pronounced when electrical storage is dispatched for resource flexibility. Following evening peak demand, there is a steep drop in energy supply from electrical storage, (positive MW total due to dispatch), to energy demand from electrical storage (negative MW due to recharging).

The maximum electrical storage dispatch in the Reference Case is roughly 4,000 MWs and results in a distinct plateau when effective load carrying capability (ELCC) is saturated. The width of the plateau represents the duration of electrical storage supplying energy at maximum dispatch. If the width of this plateau were wider (e.g., more electrical storage with longer dispatch durations across the evening peak demand period), then all the unserved load could be mitigated. Optimizing charging and dispatch times of electrical storage to extend the duration that is available for resource flexibility across the entire evening peak demand period would further increase its effectiveness to reduce the instances of unserved load.

Follow-up studies to investigate the operational capabilities of electrical storage and optimal diurnal times for charging and dispatch would better show the potential of electrical storage to mitigate the risk of unserved load at evening peak demand. In practice, there may be opportunities to accomplish this including policy, market mechanisms, and/or demand-side technology advancements.

Figure 15 shows gross load and net load with wind and solar added. While the evening demand peaks for net load are lower than that for gross load, the transitions between evening demand peaks and noon valleys are more pronounced, increasing the operational difficulty of commitment and dispatch.

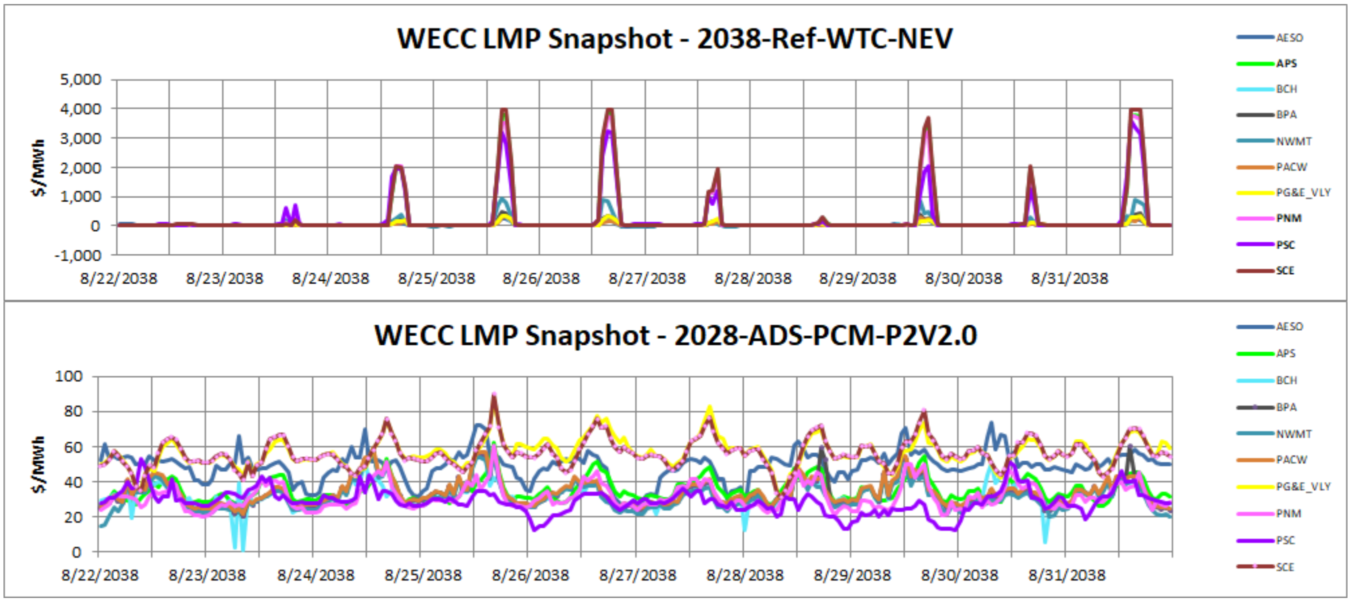
Figure 15: Comparison of Net Load – 2038 Reference Case to 2028 ADS PCM



The commitment and dispatch of resources would be more manageable and would have a lower overall production cost if the diurnal shape of gross demand could be shifted from periods when net demand is at evening peak to periods when net demand is low.

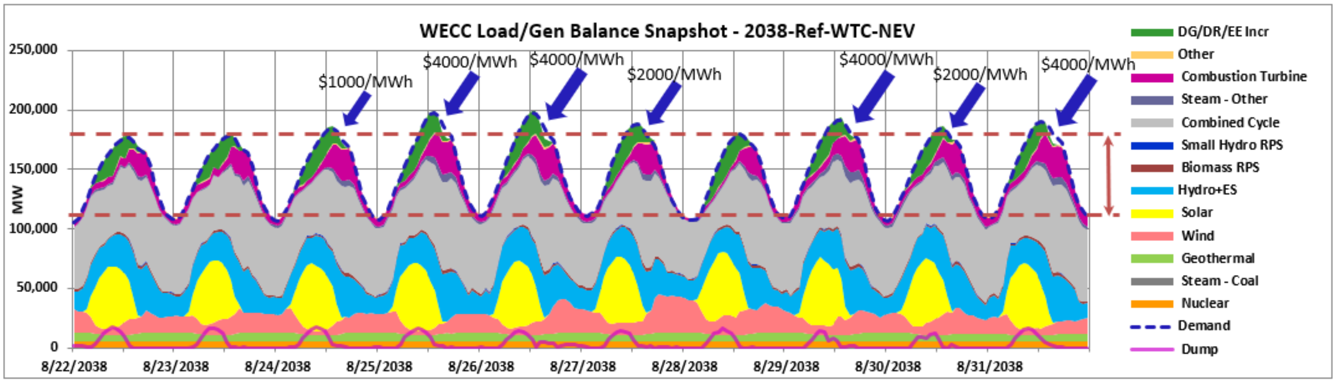
Locational marginal price (LMP) for load is shown in Figure 16.

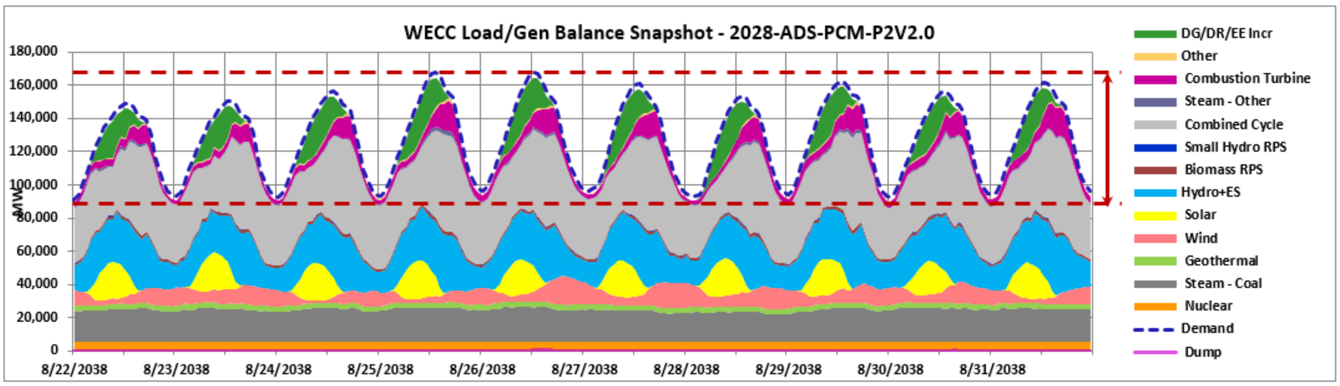
Figure 16: Comparison of LMPs - 2038 Reference Case to 2028 ADS PCM



As previously described, the spikes in LMP result when evening peak demand is outside the envelope which is also when instances of unserved load occur. The LMP spikes are highest for the APS, PNM, PSC, and SCE areas. Large LMP price differentials between areas occur when congestion is encountered that trigger the need for higher cost local generation to be dispatched and/or load to be shed (unserved). LMP prices rise to 4000 $/MWh (maximum allowed threshold defined in the PCM) when unserved load occurs, shown in Figure 16 and Figure 17, and range under 100 $/MWh when there are no occurrences of unserved load.

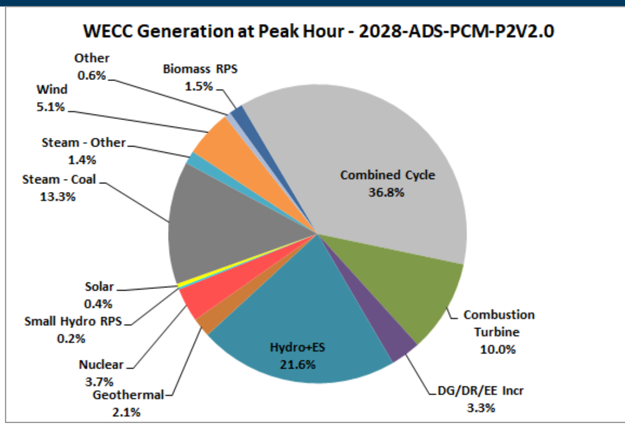
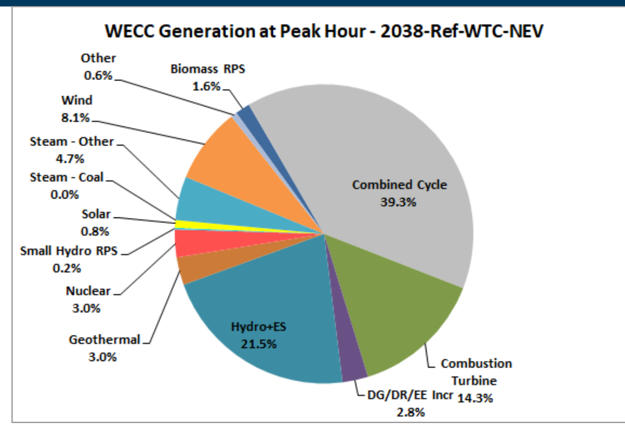
Figure 17: Correlation of LMPs and Load/Gen Balance - 2038 Reference Case to 2028 ADS PCM





There is a proportionally greater amount of wind, solar, and gas-fired generation in the 2038 Reference Case dispatch than in that of the 2028 ADS PCM, shown in Figure 18. While the dependence on gas-fired generation will increase in the future as baseload resources (primarily coal fired) are displaced and variable generation increases, increased demand-side management to shift load from evening peak periods to periods when demand is low (noon), either from market, industry, or policy mechanisms, can be highly effective in mitigating the risks of unserved load and high LMP prices, which are ultimately absorbed by the consumer.

Figure 18: Comparison of Generation at Peak Hour - 2038 Reference Case to 2028 ADS PCM

2028 ADS PCM	2038 Reference Case
	

Here, generation dispatch from coal is completely displaced, primarily due to scheduled retirements and a \$55/ton CO_2 cost (as modeled in the Reference Case). There are also noticeable increases in dispatch from gas fired generation and wind. Solar represents less than 1% of the dispatch at evening peak for both cases, which further illustrates the poor ELCC of solar at evening peak despite a significant increase in annual energy production from solar (discussed in more detail later in this report).

RC: Generation

Figure 19 shows the annual resource energy production mix for the 2038 Reference Case as compared to the 2028 ADS PCM.

The terms used in Figure 19 are:

Ref: 2038 Reference Case.

WTC: With transmission constraints enforced.

NEV: No dispatchable DER in the form of electric vehicle storage (DER-EV).

Figure 19: Comparison of Annual Energy Production (GWh) – 2038 Reference Case to 2028 ADS PCM

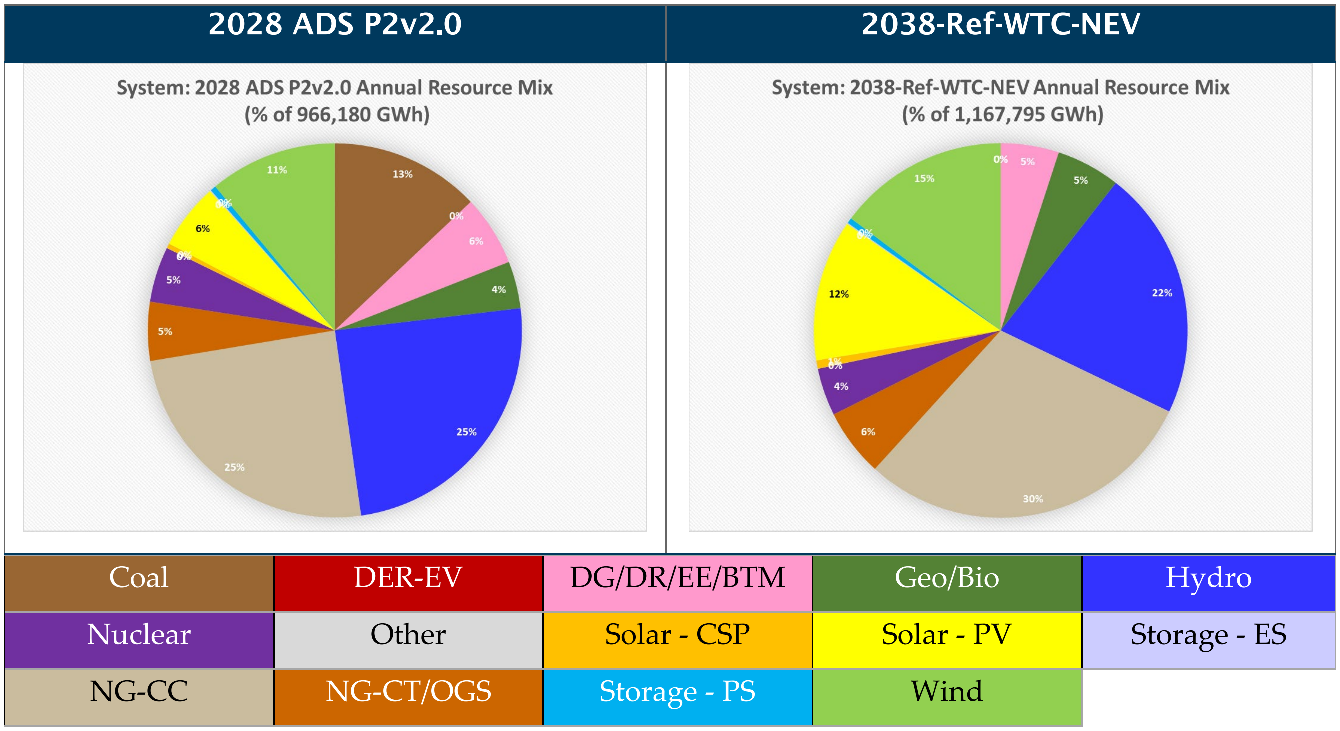
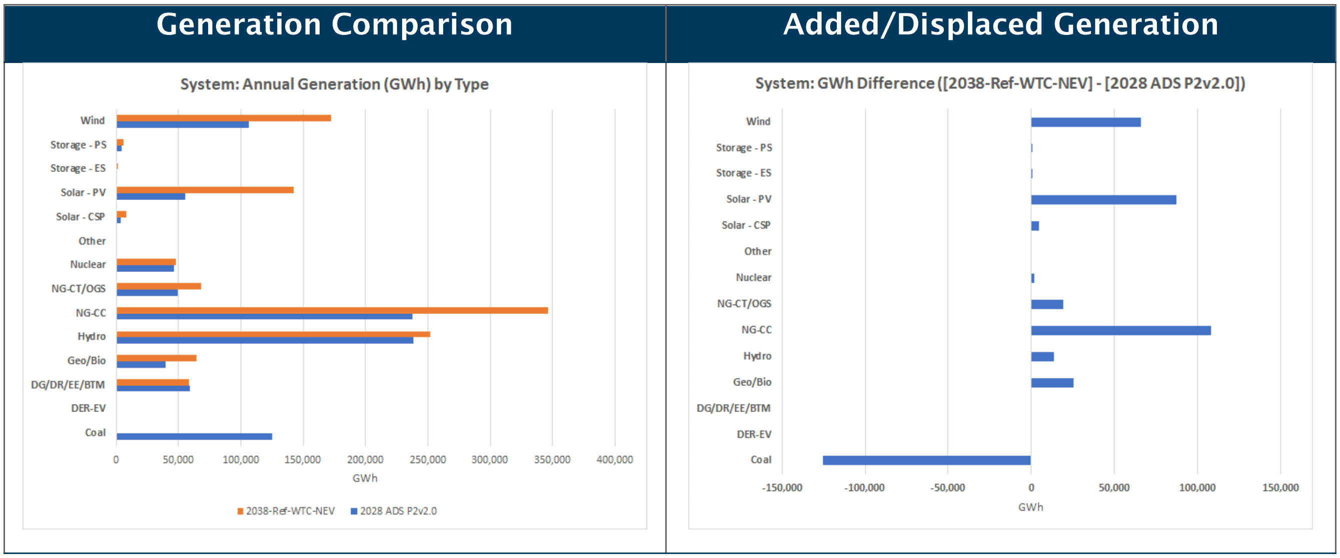


Figure 20: Reference Case – Resource Additions/Displacements by Type (GWh)

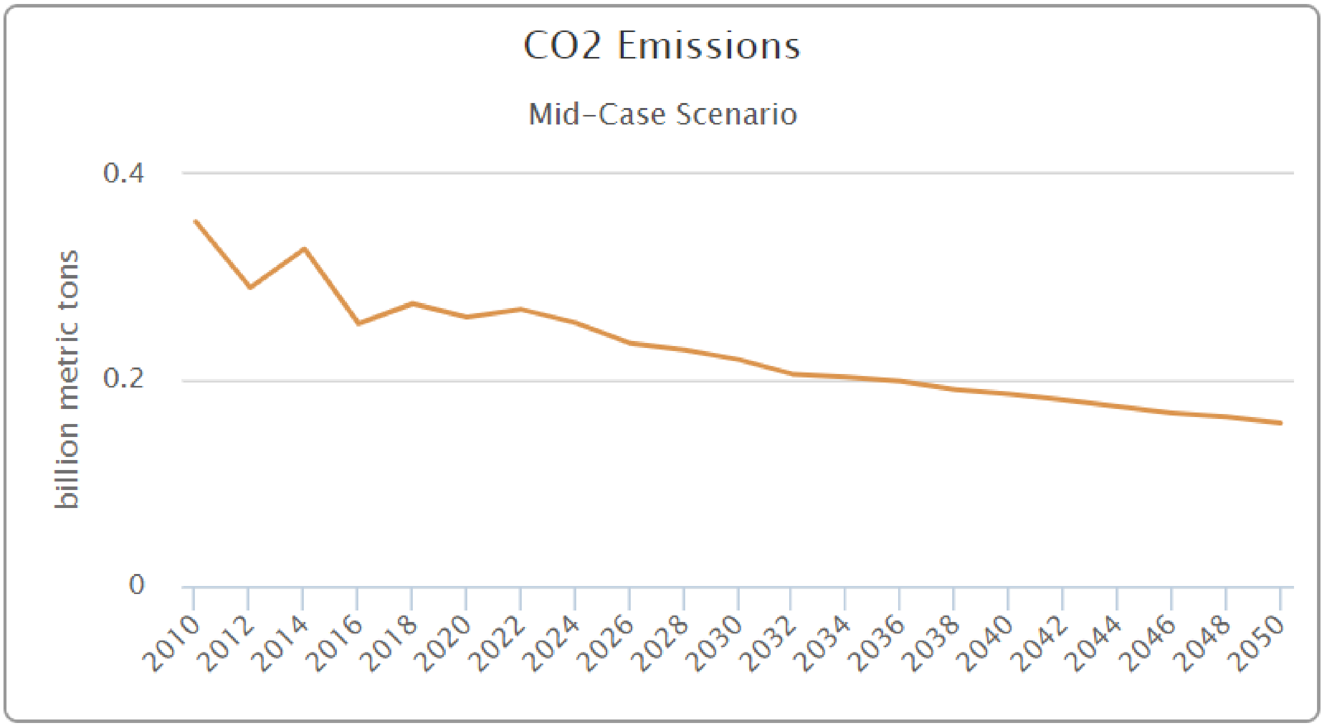


As Figure 19 and Figure 20 show, coal fired generation was completely displaced due to retirements based upon stated policy and industry decisions and a $55/ton CO_2 cost assumption included within the simulation. Energy production from gas fired generation, solar, and wind are increased significantly. While the annual energy production from solar in the Reference Case doubled from 6% in the 2028 ADS PCM to 12%, the dispatch from solar at evening peak demand for both cases was less than 1% as discussed earlier.

The dependence on gas fired generation (both combined cycle and combustion turbines) is projected to increase to offset the displacement of coal, beyond what renewable resources will provide. In the PCM simulations, renewable resources have low production costs and are largely committed and dispatched as "price takers," while natural gas fired resources are committed and dispatched largely based on marginal price signals as they are today. This emphasizes the continued future dependence on gas fired generation both in terms of adequacy and resource flexibility at evening peak demand.

The reduction in CO2 emissions in the Western Interconnection for the RCCRP (Mid-Case Resource Portfolio) is shown in Figure 21. [17]

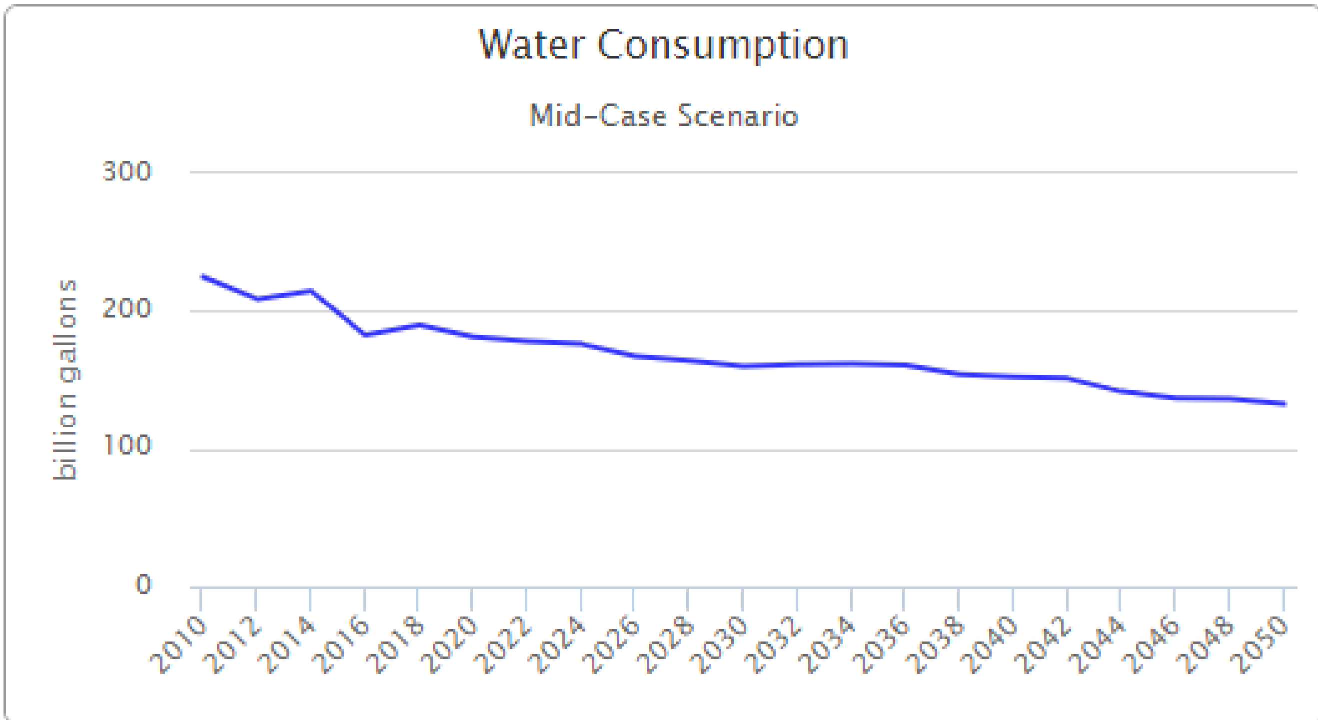
Figure 21: CO2 Emissions in West for NREL Mid-Case Resource Portfolio [17]



CO_2 emissions in the RCCRP are reduced by 17% in 2028 relative to 2018, to 0.19 billion metric tons from 0.23 billion metric tons . The reduction in CO_2 emissions from 2018 to 2038 is 30% (from 0.27 billion metric tons to 0.19 billion metric tons). Since the foundations of the candidate resource portfolios used in the Scenario simulations are derived from the RCCRP that has been augmented with dispatchable DER-EV (representing less than 2% of energy production from the portfolios), this reduction in CO_2 emissions for the RCCRP generally reappears across all the Scenario simulations.

The reduction in water consumption for thermal cooling in the Western Interconnection for the RCCRP (Mid-Case Resource Portfolio) is shown in Figure 22. [17]

Figure 22: Water Consumption in West for NREL Mid-Case Resource Portfolio



Water consumption for thermal cooling in the RCCRP is reduced by 14% as of 2028, to 164 billion gallons from 190 billion gallons. The reduction in water consumption for thermal cooling from 2018 to 2038 is 19% (from 190 billion gallons to 154 billion gallons). Since the foundations of the candidate resource portfolios used in the Scenario simulations are derived from the RCCRP that has been augmented with dispatchable DER-EV (representing less than 2% of energy production from the portfolios), this reduction in water consumption for thermal cooling for the RCCRP generally reappears across all the Scenario simulations.

RC: Inter-Regional

In this section, path use in the 2038 Reference Case is compared with that in the 2028 ADS PCM case. The most heavily used paths in the 2038 Reference Case compared to the 2028 ADS PCM are shown in Figure 23 and Figure 24 respectively.

Figure 23: Most Heavily Used Paths – 2038 Reference Case

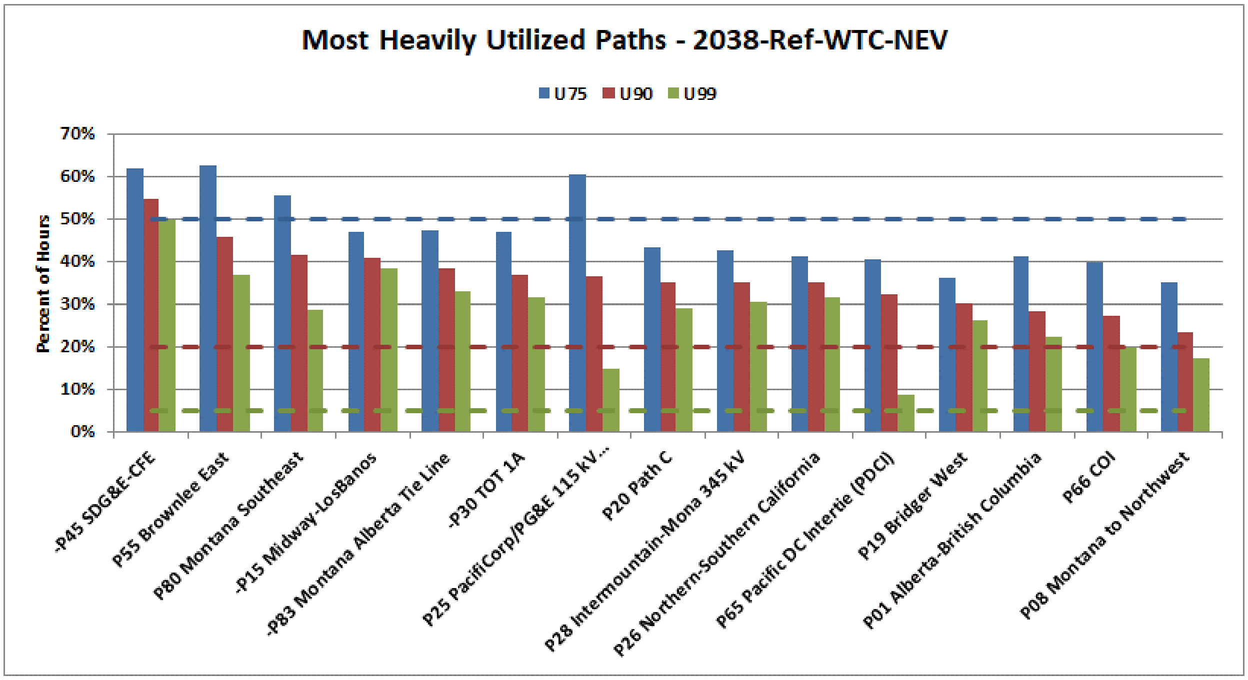
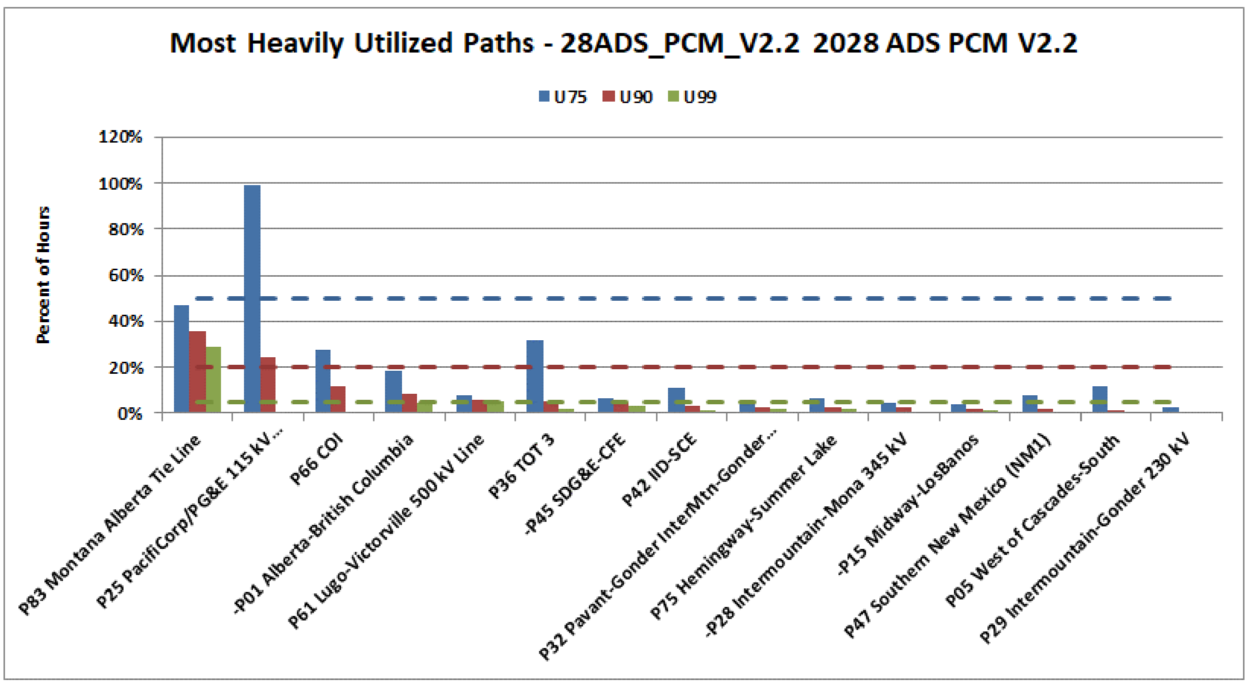


Figure 24: Most Heavily Used Paths - 2028 ADS PCM



A cross-correlation of heavily used paths between the 2038 Reference Case and the 2028 ADS PCM is shown in Table 6 with paths highlighted in yellow being among the top 15 most heavily used paths of both cases. Paths highlighted in blue are among the top 15 of the 2028 ADS PCM only, and paths highlighted in orange in the top 15 of the 2038 Reference Case only.

Table 6: Correlation of Heavily Used Paths to Regions – 2038 Reference Case

Path	Region(s)
P01 Alberta-British Columbia	Alberta, British Columbia
P05 West of Cascades-South	Northwest
P08 Montana to Northwest	Northwest
P15 Midway-LosBanos	California
P19 Bridger West	Basin, Rocky Mountain
P20 Path C	Basin, Northwest
P25 PacifiCorp/PG&E 115 kV Interconnection	California, Northwest
P26 Northern-Southern California	California
P28 Intermountain-Mona 345 kV	Basin
P29 Intermountain-Gonder 230 kV	Basin
P30 TOT 1A	Basin, Rocky Mountain
P32 Pavant-Gonder InterMtn-Gonder 230 kV	Basin
P36 TOT 3	Basin, Rocky Mountain
P42 IID-SCE	California
P45 SDG&E-CFE	California, Mexico
P47 Southern New Mexico (NM1)	Southwest
P55 Brownlee East	Basin, Northwest
P61 Lugo-Victorville 500 kV Line	California
P65 Pacific DC Intertie (PDCI)	California, Northwest
P66 COI	California, Northwest
P75 Hemingway-Summer Lake	Northwest
P80 Montana Southeast	Northwest
P83 Montana Alberta Tie Line	Alberta, Northwest
Heavily Used in the 2028 ADS PCM Only	
Heavily Used in the 2038 Reference Case Only	
Heavily Used in both the 2038 Reference Case and the 2028 ADS PCM	

Figure 24, Figure 23, and Table 6 show a noticeable increase in path use for the 2038 Reference Case around the Basin Region and transfers to Southern California from the Northwest. This result also appears in a comparison of regional transfers of annual energy between the Reference Case and the 2028 ADS shown in Figure 25, where the diameters of the black circles depict the load requirements relative to generation (see the multi-color pie charts). When load is greater than generation, the black load circle is behind the generation pie chart. When load is less than generation, the black load circle is in front of the generation pie chart. The arrows represent energy transfers with the widths of each corresponding to total amounts; arrow colors further depict scale, with larger transfers as red and lower transfers as blue.

Figure 25: Path Flow Comparison of 2038 Reference Case to 2028 ADS PCM

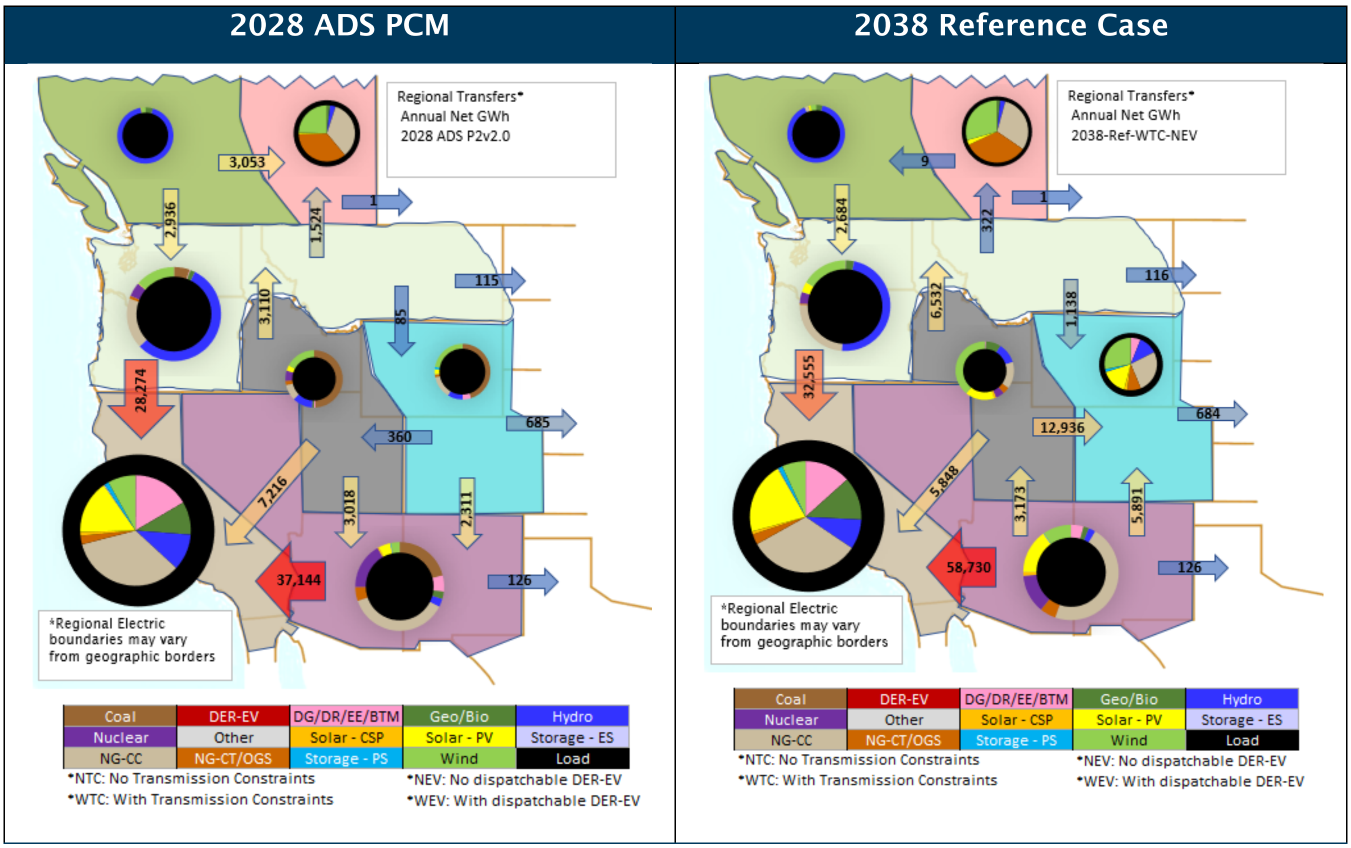


Figure 25 shows:

- Energy production from coal is completely displaced, primarily in the Basin, Northwest, Rocky Mountain, and Southwest regions.
- Energy production from gas fired resources increases noticeably in the Basin, Northwest, Rocky Mountain, and Southwest regions, offsetting displacements of coal fired resources.
- Energy production from solar resources increases noticeably in the Basin, California, Rocky Mountain, and Southwest regions.
- Energy production from wind resources increases noticeably in the Alberta, Basin, Northwest, and Southwest regions.

- Annual energy transfers into the Alberta region decrease with net neutral resource adequacy modeled for Alberta (based on the Alberta Integrated Resource Plans). [14]
- Annual energy transfers from the British Columbia region to Alberta region decrease due to net neutral resource adequacy modeled for Alberta.
- Annual energy transfers from the Basin region increase, primarily in the direction of the Northwest and Rocky Mountain regions with increased energy production from wind, solar, and gas resources outpacing load growth.
- Annual energy transfers into the California region increase noticeably as load growth outpaces increased energy production that originates primarily from solar resources.
- Transfers from the Southwest to the Basin and Rocky Mountain regions reverse direction where exports from the Southwest increase in the 2038 Reference Case relative to the 2028 ADS PCM.
- Transfers from the Basin to the Rocky Mountain region reverse direction where the Basin is exporting power to the Rocky Mountain region to help replace energy production lost from displaced coal fired generation.
- Annual energy transfers from the Northwest region to California, primarily due to increased loop flow of energy from the Basin and Southwest.
- Annual energy transfers into the Rocky Mountain region increase noticeably as the Rocky Mountain region shifts from net exports to net imports due to a large displacement of coal not being entirely offset from increases in wind, solar, and natural gas.
- Annual energy transfers from the Southwest region increase noticeably with noticeable increases in energy production from wind, solar, and gas fired resources, despite the displacement of coal fired resources.

RC: Seasonal Variations

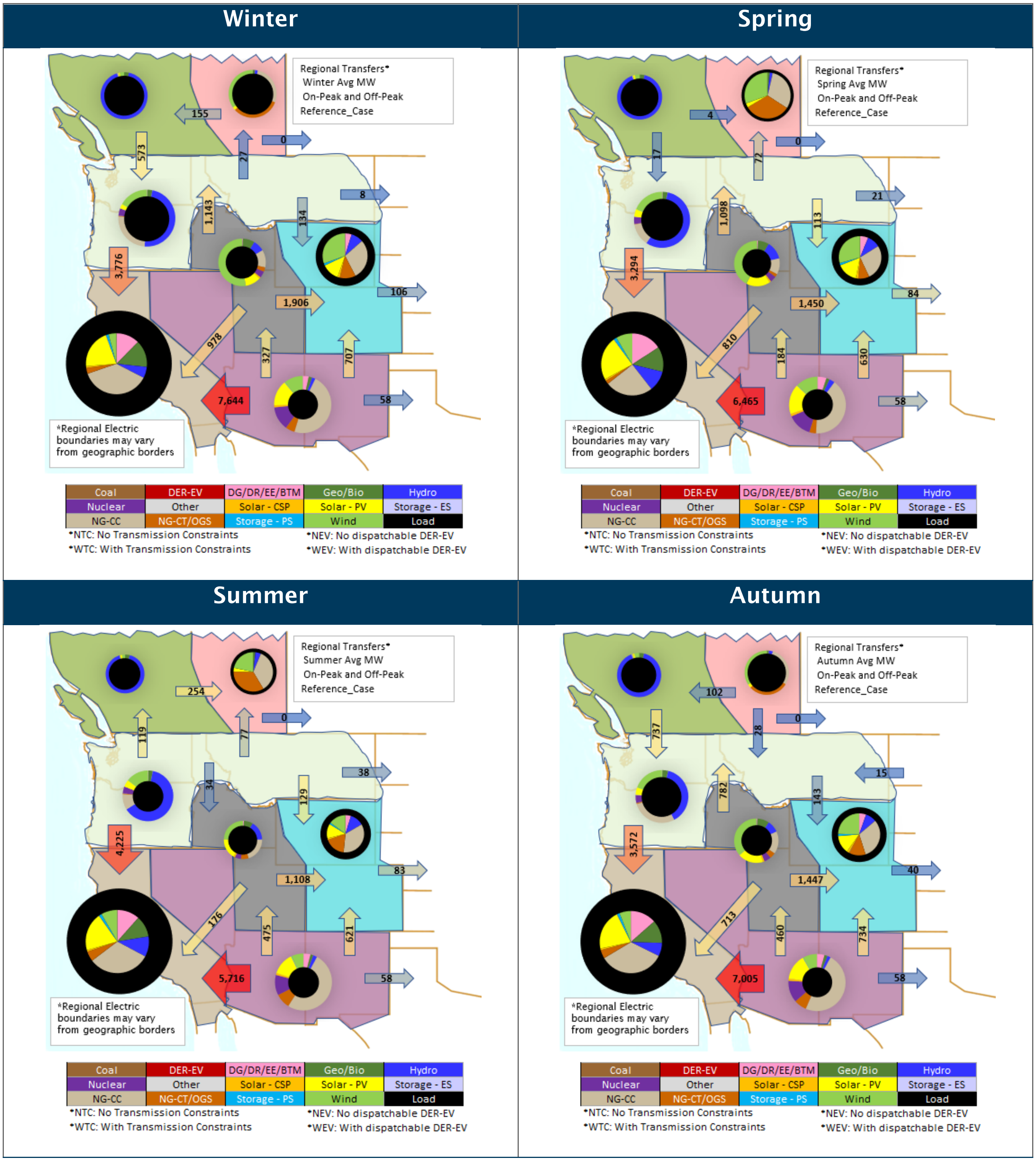
The seasonal variations of path flows are shown in Figure 26 where:

- The Alberta region is a net importer in summer and spring (to a lesser extent) and a net exporter during winter and autumn (to a lesser extent) with the energy production mix relatively constant proportionally across all seasons.
- The British Columbia region is a net exporter across all seasons where energy transfers to the Northwest region are greatest during autumn and winter and energy transfers to Alberta are greatest during the summer, supplemented by loop flow from the Northwest in summer.
- The Basin region is a net exporter across all seasons where energy transfers out of the Basin to other regions are uniform across all seasons with most energy transfers going to the Rocky Mountain Region; loop flow comes from the Southwest region.
- The California region is a net importer across all seasons where energy transfers are greatest in winter and autumn and are least in spring and summer. This seasonal variation in energy

transfers are largely due to the increased amount of solar in the resource mix with energy production from solar at its highest in summer.

- The Northwest region is a net exporter across all seasons where energy transfers are greatest in summer and are least in winter.
- The Rocky Mountain region is a net importer across all seasons where energy transfers are greatest in winter and are least in summer. This seasonal variation is largely due to higher load demand in the Rocky Mountain region relative to the rest of the system and commitment of cheaper resources outside of the Rocky Mountain region to meet system needs.
- The Southwest region is a net exporter across all seasons where energy transfers are greatest in winter and are least in summer. This seasonal variation is largely due to increased hydro production from the Northwest region in summer and decreased hydro production in winter when the load demand in the Northwest is highest.

Figure 26: Seasonal Path Flow Variations for 2038 Reference Case



As Figure 26 shows, California represents approximately 34% of the total annual system load energy requirement while California's energy production represents 30% of that of the system, making it a net annual importer of energy; this occurs across all seasons.

Energy transfers from the Northwest to California are greatest during summer when load in California is at its greatest and hydro energy production in the Northwest is at its greatest. Energy transfers from the Northwest to California are least during winter when load in California is less than that in summer, load in the Northwest is at its greatest, and hydro energy production in the Northwest is much less than that in summer.

Energy transfers from the Southwest to California are greatest during the winter when energy transfers from the Northwest are at their least, while energy transfers from the Southwest to California are least in summer when energy transfers from the Northwest are at their greatest. In this regard, energy transfers from the Northwest and the Southwest to California share an inverse seasonal relationship to one another.

RC: Key Takeaways

The key takeaways from the 2038 Reference Case simulations are:

- Baseload coal fired generation is shown as completely displaced primarily due to announced policy and industry decisions in the West to retire this resource and the addition of a $55/ton CO_2 cost (as discussed earlier in the Assessment Approach section of this report).
- Replacement of baseload resources (primarily coal fired) with variable resources such as wind and solar increases the need for generation that can provide resource flexibility at evening peak demand.
- While annual energy production for solar doubled in the Reference Case from that of the 2028 ADS PCM to 12%, the dispatch from solar at evening peak demand averaged less than 1%. The low ELCC from solar at evening peak demand is of little benefit when unserved load occurs, and solar-driven energy spillage increases when energy production from solar is high and load demand is low.
- Demand-side management is probably the most effective approach available to mitigate the risk of unserved load at higher load demand levels. With higher concentrations of solar in the diurnal energy commitment mix, use of demand-side management mechanisms to shift load demand from evening peak demand to periods when load demand is low and when energy production from solar is high offers great promise. In this context, it is ideal to charge electrical storage when energy production from solar is high and dispatch storage when solar energy production is low and load demand is high (such as during evening peak periods).
- Unserved load in the amount of 306 GWh occurred and was primarily evident during summer and in the Basin, Rocky Mountain, and Southwest regions.

- The risk of unserved load is greatest when evening peak demand exceeds a 180 GW upper bound and when resource flexibility declines above this threshold. While this threshold primarily results from the amount of resources in the RCCRP that can provide flexibility at evening peak demand, simultaneous feasibility test (SFT) commitment rules for more resource flexibility could lower this threshold, but at a higher commitment cost. SFT rules are associated with the day-ahead commitment of resources that must be met to assure that adequate resources will be available to meet the day-of dispatch needs including that of hourly energy balance, ramping, and reserve flexibility.
- A greater dependence on gas fired generation for adequacy and resource flexibility at evening peak demand will occur with the displacement of coal and as renewable penetration increases so too will resource variability.
- Electrical storage is a useful tool to mitigate unserved load but will require mechanisms to shape the diurnal availability of electrical storage when it is needed most. Mechanisms that could be initiated in combination from policies, markets, or industry.
- An operational partnership between solar and electrical storage so that the combined net energy supply would be relatively constant would greatly reduce the operational challenges introduced by solar and the reliability risk of unserved load.
- LMPs, as modeled in the PCM, reach a maximum of $4000/MWh when unserved load occurs. LMPs will generally average below $40/MWh and will generally be less than $100/MWh when congestion occurs in the absence of unserved load. Many nodal markets, however, have a maximum LMP threshold that is less than $4000/MWh. The maximum LMP threshold set does not have much impact on the instances in which unserved load occurs unless the price range of unserved load relative to marginal resource dispatch is narrow enough to make unserved load an acceptable dispatch option. This is contrary to the reliability mission of WECC. In this regard, the $4000/MWh represents the cost of unserved load in the PCM and, by proxy, to the consumer.
- CO_2 emissions for the RCCRP decreased by 17% relative to the 2028 ADS PCM and by 30% relative to 2018 recorded levels.
- Transmission path use significantly increased in the Basin, Southwest, and Rocky Mountain Regions, attributable to greater dependence on the Basin and Southwest for energy production and the displacement of coal fired generation in the Rockies.
- Energy transfers from the Southwest to California are greatest during the winter when energy transfers from the Northwest are at their least while energy transfers from the Southwest to California are least in summer when energy transfers from the Northwest are at their greatest. In this regard, as energy transfers to California from the Northwest decline, energy transfers to California from the Southwest increase and vice versa.

Scenario 1 (SC1)

SC1 is characterized in the Scenario Matrix as including open markets with limited customer adoption of new service options. The following lists the assumptions that came from the narratives for SC1. [16] Following each assumption are descriptions of the modeling approaches used:

- Regulations are open and flexible to allow a range of energy service options.
  Captured primarily by assumptions about technology advancement in terms of cost and performance. In other words, how will regulations affect technology innovation and customer adoption? In the case of this scenario, the NREL Moderate Assumptions for Technology Advancement is chosen. The Moderate Advancement case is intended to reflect a moderate increase in technology trends beyond current levels because of innovation, research and development, deployment, cost reductions, and performance improvements through 2050. [1]
- Customer adoption of new energy options is limited by new products and not correspondent with customer interests (e.g., benefits don't appear to justify costs or other.)
  The NREL Reference Trajectory for End-Use Technology Adoption was used. The Reference Electrification Adoption scenario represents a business-as-usual outlook where only incremental changes with respect to electrification occur. In particular, the Reference Scenario includes policies that existed in 2017 only. It also excludes any dramatic technological, societal, or behavioral shifts as they relate to the adoption of end-use equipment. It reflects a future in which the rate of adoption of electric technologies roughly follows current trends. In other words, it embodies an electrification transition that remains slow with only incremental gains even by 2050. [1]
- The bulk transmission system is maintained to back up reliability for the interconnection.
  SC1 is modeled with the same reliability requirements as that of the 2028 ADS PCM including transmission path limits, resource flexibility, and other operational security constraints.

SC1: Modeling Components

The modeling components below were selected based on the narrative for SC1 to the extent that changes from that of the Reference Case were needed to capture the intentions behind this scenario narrative. While it is not possible to match all parts of the narrative with an equivalent quantitative measure, the learning process involved in scenario modeling advances with additional iterations, as should the modeling capabilities.

Load Models: Derived from the NREL Demand-Side Scenario [13] with the Reference Customer Adoption of new service options and with Moderate Technology Advancement assumptions as further described in Appendix D under "Load Models."

Generation Resource Portfolio: The Scenarios Candidate Resource Portfolio (SCRP) is derived from the RCCRP with the addition of dispatchable DER-EV derived from the NREL Demand-Side Scenario used for SCENARIO 1 as further described in Appendix D under "Generation Resource Models."

Transmission Topology: The transmission topology is that contained within the 2028 ADS PCM with interface paths monitored as further described in Appendix D under "Transmission Models. "

Limitations: There can be no exact conversion of qualitative statements into matching quantitative inputs. The qualitative narrative was used to guide the selection of quantitative components as reflecting the intent expressed in the scenario narrative. It is not possible to match all parts of the narrative with an equivalent quantitative measure. However, as data resources and modeling capabilities improve, this associative process can improve scenario modeling.

SC1: Load

SC1 produced 10 GWh of unserved load, compared to the 306 GWh of unserved load that resulted in the 2038 Reference Case. Unserved load in SC1 occurred primarily in the Basin and Rocky Mountain regions and, to a lesser extent, in the Southwest region as shown in Figure 27. Most of the unserved load in SC1 was concentrated in the month of August, while unserved load occurred across the summer season in the 2038 Reference Case (shown in Figure 28). While the annual load energy requirements of SC1, SC3, and the Reference Case are similar, unserved load for SC1 is less than that of the Reference Case because SC1 includes dispatchable DER in the form of electric vehicle storage (dispatchable DER-EV available at evening peak load demand) while the Reference Case does not.

Figure 27: Unserved Load for 2038 Scenario 1

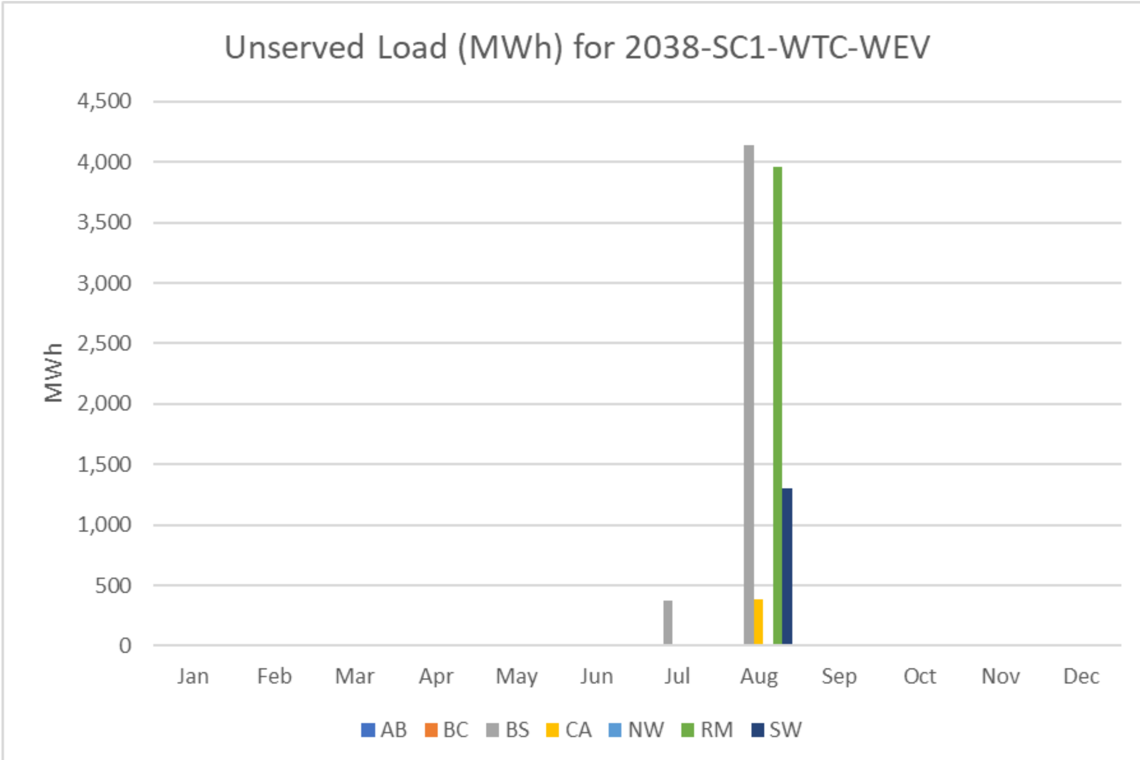
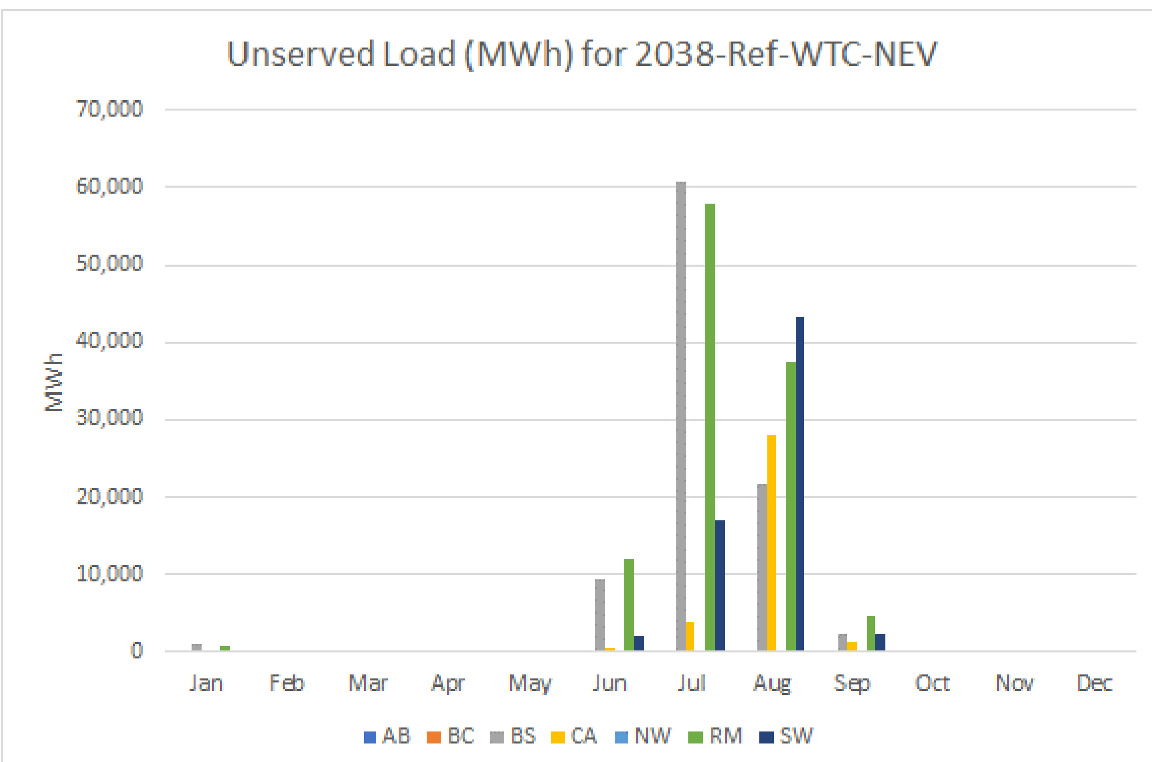


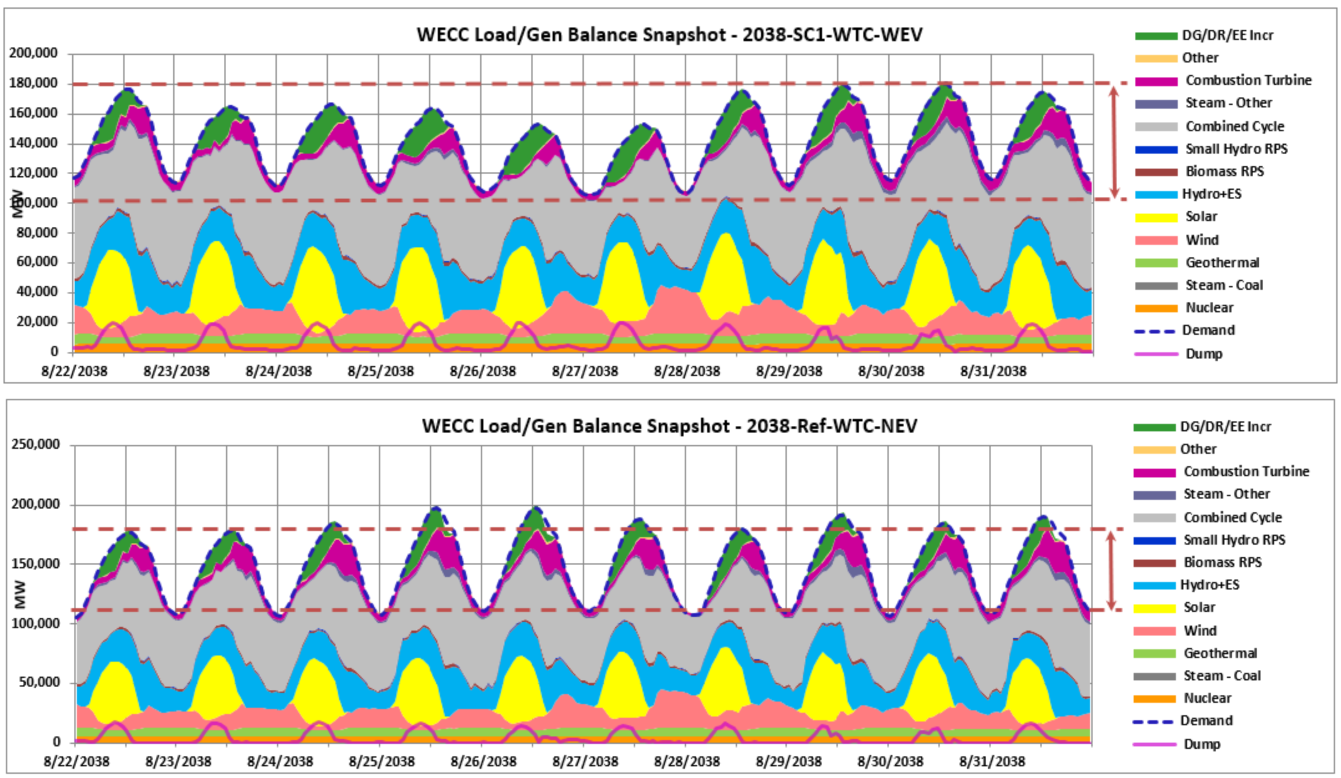
Figure 28: Unserved Load for 2038 Reference Case



Total unserved load in SC1 was much lower than what appears in the Reference Case. This was attributed to less evening peak demand, as well as the inclusion of dispatchable DER-EV in the SCRP for SC1 (available for dispatch at evening peak demand), while the Reference Case had no dispatchable DER-EV.

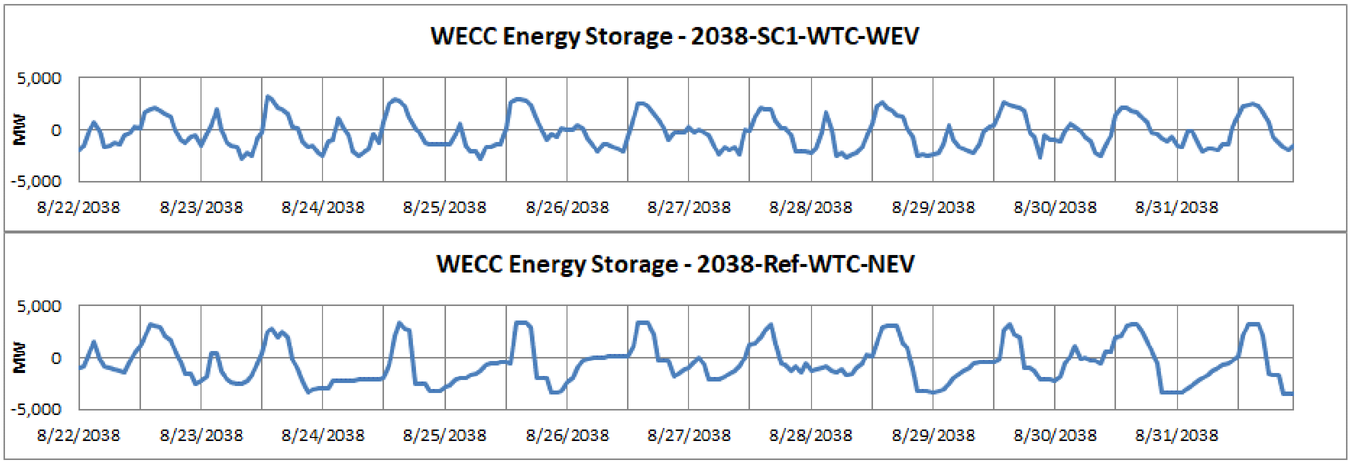
Another important observation is that the evening peak demand levels in SC1 are less than the 180,000 MW upper limit of the envelope described for the Reference Case, suggesting that the availability of resource flexibility at evening peak demand in SCRP is adequate up to this threshold but poses a greater risk of unserved load when demand exceeds this threshold. While this threshold is primarily dependent on the availability of resource flexibility at evening peak demand in the SCRP, other factors that affect this include adjustments to SFT commitment rules for more resource flexibility. Adjustments to SFT commitment rules for more resource flexibility will, however, increase commitment costs which ultimately get passed on to the consumer.

Figure 29: Comparison of Load/Gen Balance - 2038 Scenario 1 to 2038 Reference Case



A comparison of the diurnal energy shapes of electrical storage between SC1 and the Reference Case is shown in Figure 30.

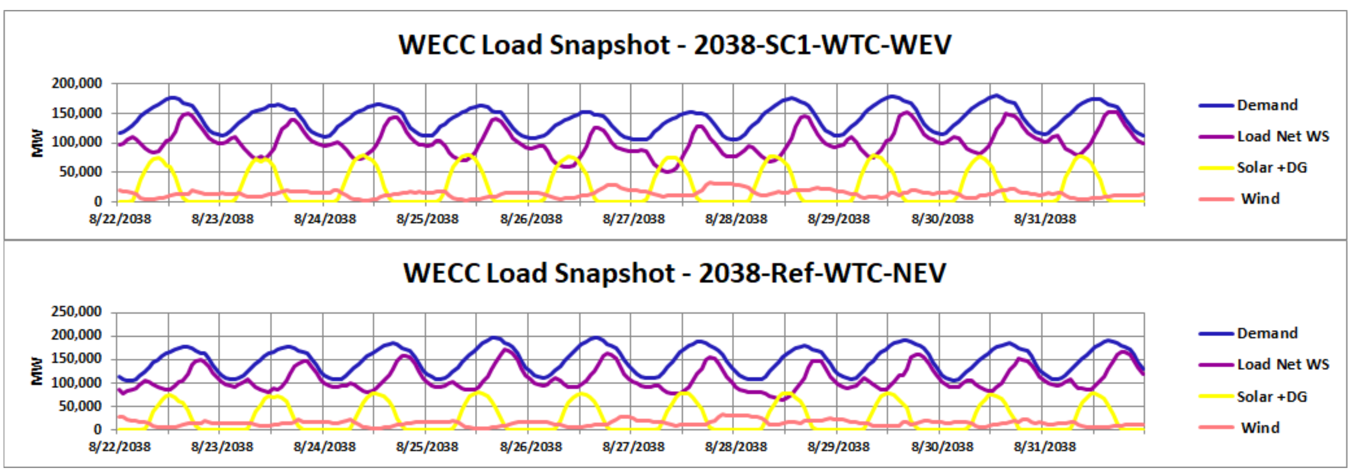
Figure 30: Comparison of Electrical Storage - 2038 Scenario 1 to 2038 Reference Case



The diurnal commitment and dispatch shape of electrical storage in SC1 is more random and less uniform than that in the Reference Case. Demand at evening peak is less for SC1 than for the Reference Case and, therefore, the need for resource flexibility from electrical storage at evening peak is less and the diurnal shape of that dispatch is more random.

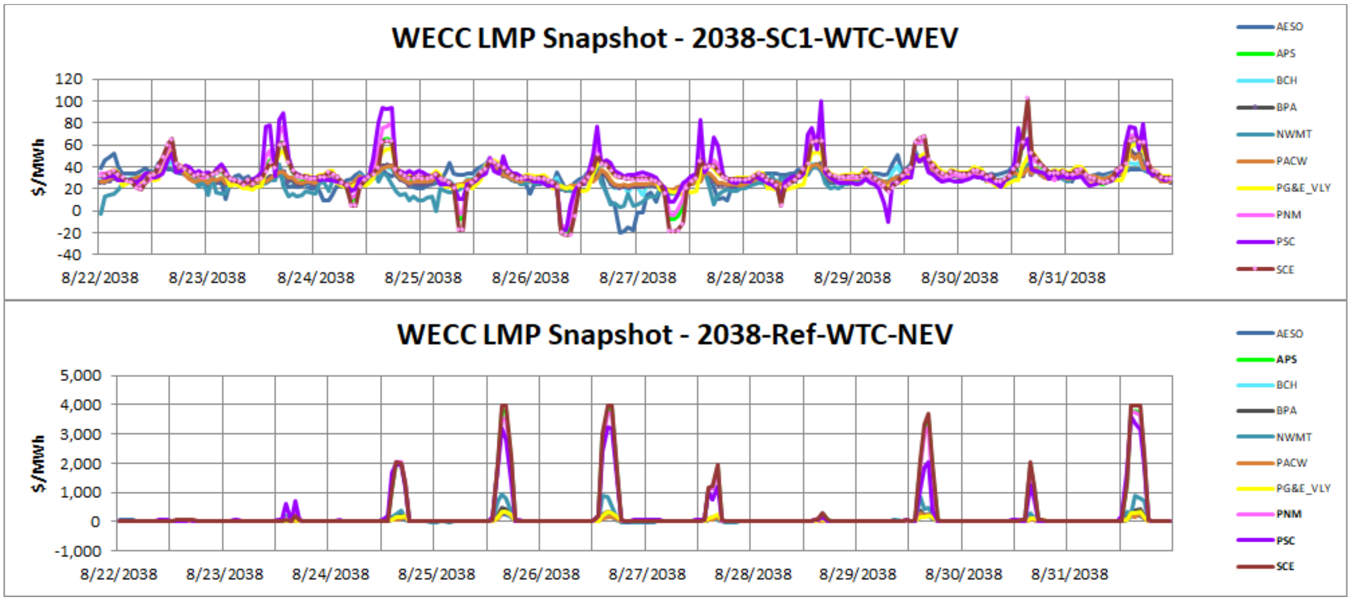
The effect of variable generation on net load demand for SC1 is shown in Figure 31. The diurnal shapes of net load demand for SC1 are like the Reference Case since gross load demand is just slightly less than the Reference Case and the dispatch of solar is essentially the same, which is dominate in accentuating the maximum net load demand.

Figure 31: Comparison of Net Load – 2038 Scenario 1 to 2038 Reference Case



Locational marginal price (LMP) for load is shown in Figure 32. LMP price spikes are less than $100/MWh and are more random, primarily due to the instances of congestion, while price spikes for the Reference Case reach the maximum of $4000/MWh when unserved load occurs. Energy spillage occurs when LMPs turn negative due to excess energy production relative to load demand.

Figure 32: Comparison of LMPs - 2038 Scenario 1 to 2038 Reference Case

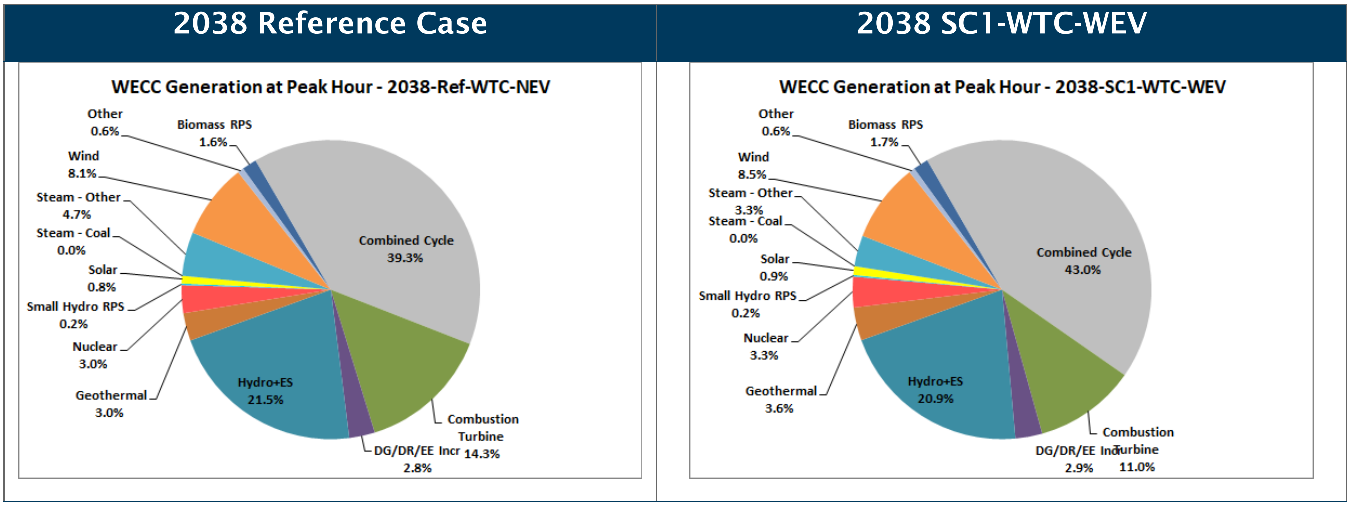


The energy production mix for SC1 is compared to the Reference Case at evening peak hours in the ten-day period examined (shown in Figure 33). The energy production mixes between SC1 and the Reference Case are constant except in the case of gas fired generation. Gas fired generation was committed and dispatched in all the simulations only after the renewable and nuclear resources were fully committed and dispatched. Gas fired generation also serves most of the resource flexibility needs at evening peak.

There is a greater commitment and dispatch of gas fired combustion turbines for the Reference Case than for SC1 due to the occurrence of unserved load in the Reference Case, and the fast start and performance characteristics of combustion turbines needed during evening peak demand. In the resource stack, combustion turbines are more expensive to run and are therefore committed mainly for resource flexibility at evening peak demand. The dependence on gas fired generation will increase, both with respect to adequacy and resource flexibility, given coal retirements and increased penetration of variable generation from renewable resources.

The commitment and dispatch of non-gas fired resources relatively constant across all scenarios and the Reference Case since they are less costly in the overall resource supply stack. Further, renewable resources are generally committed as price takers, since their lack of fuel costs make their operating costs much less than that of gas-fueled generation. Gas fired resources and storage are effectively committed and dispatched to track incremental net changes in hourly load demand above that supplied by resource types that are less costly to operate. Energy production from gas fired resources is slightly less in SC1 than that in Reference Case since the load levels in SC1 are slightly less than those in the Reference Case. Solar represents less than 1% of the dispatch at evening peak for both cases, which further illustrates the poor ELCC of solar at evening peak despite a 12% share of annual energy production.

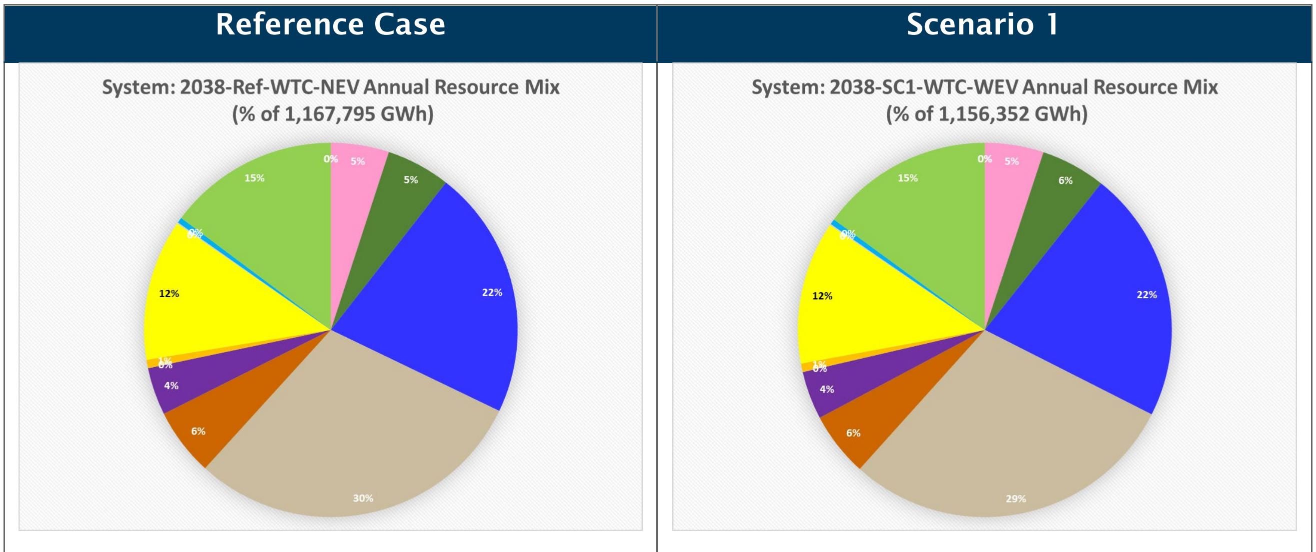
Figure 33: Comparison of Generation at Peak Hour - 2038 Scenario 1 to 2038 Reference Case



SC1: Generation

The annual resource energy production mix for SC1 as compared to the Reference Case is shown in Figure 34.

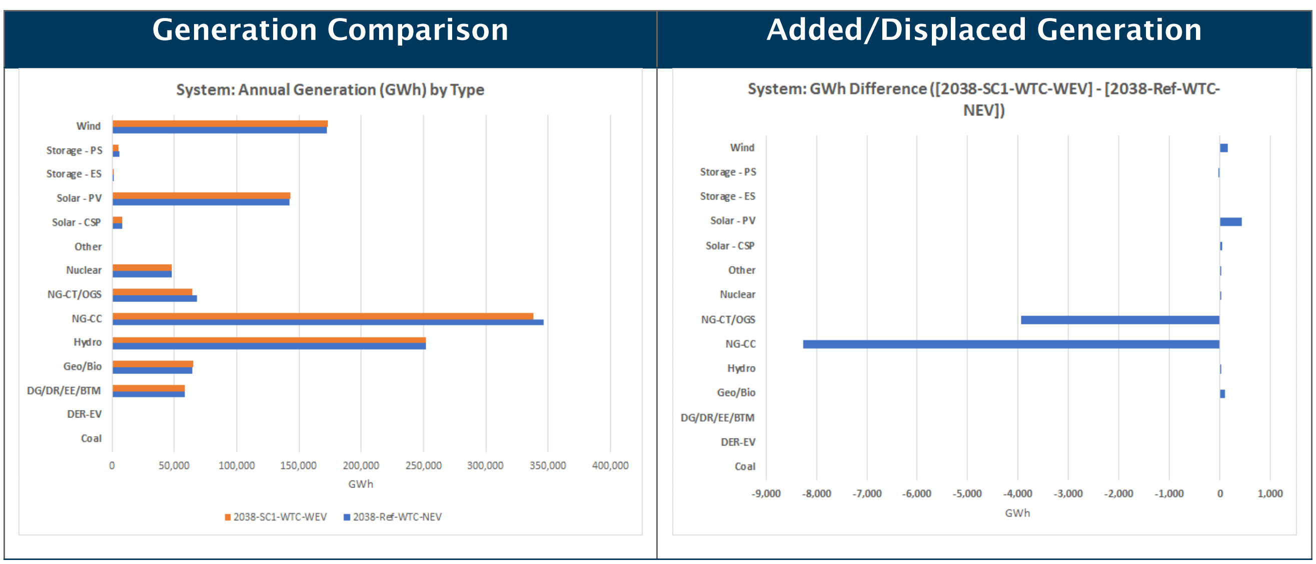
Figure 34: Comparison of Annual Resource Energy Production (GWh) – Scenario 1 to 2038 Reference Case



Coal	DER-EV	DG/DR/EE/BTM	Geo/Bio	Hydro
Nuclear	Other	Solar - CSP	Solar - PV	Storage - ES
NG-CC	NG-CT/OGS	Storage - PS	Wind	

The change in energy production between SC1 and the Reference Case is shown in Figure 35.

Figure 35: Scenario 1 – Resource Additions/Displacements by Type (GWh)



The largest change in energy production was a decrease in gas fired generation in response to the decreased load levels in SC1 relative to the Reference Case. As explained previously, gas fired resources and storage are effectively committed and dispatched to track incremental net changes in hourly load demand above that supplied by resource types that are less costly to operate. Since the load levels for SC1 are less than the Reference Case, the commitment and dispatch of gas fired resources are less. This further illustrates the central role of natural gas in the commitment and dispatch of energy as load levels change, especially during periods of evening peak demand when ELCC from solar resources are negligible. There was a slight increase in energy production from resources other than gas due to reduced energy spillage in instances where minimum load levels were slightly higher for SC1 than for the Reference Case.

SC1: Inter-Regional

The most heavily used transmission paths for SC1 are shown in Figure 36, as compared to those for the Reference Case shown in Figure 37.

Figure 36: Most Heavily Used Paths – Scenario 1

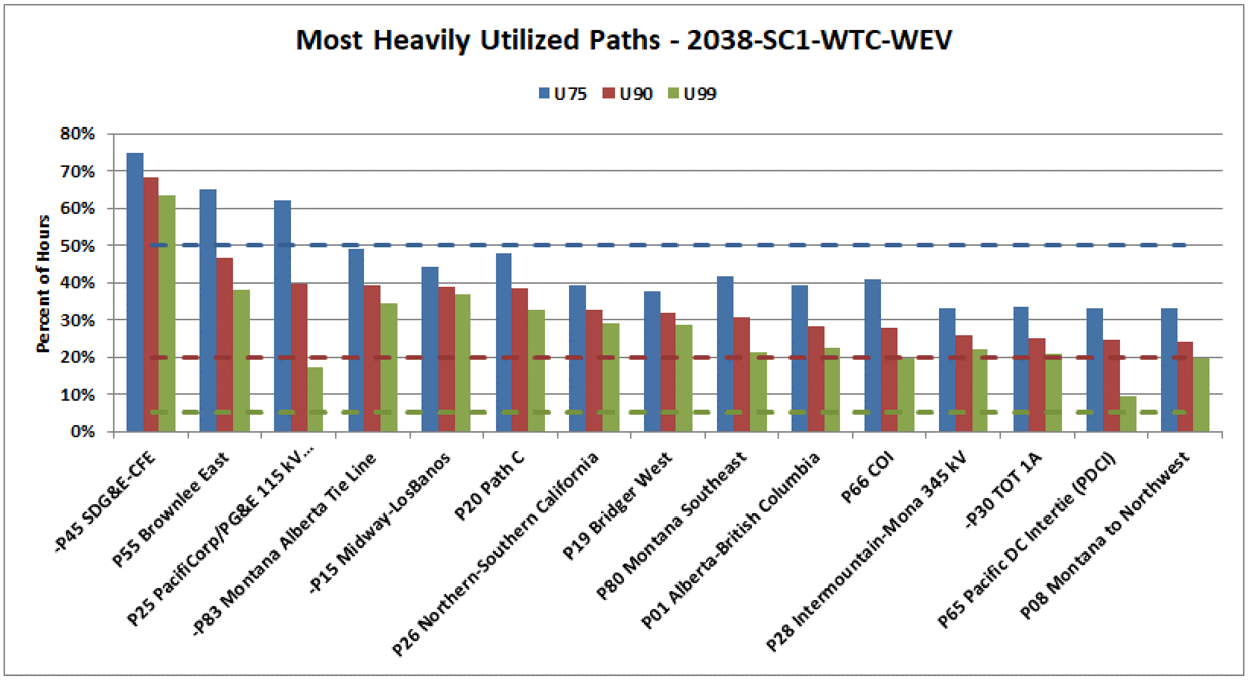
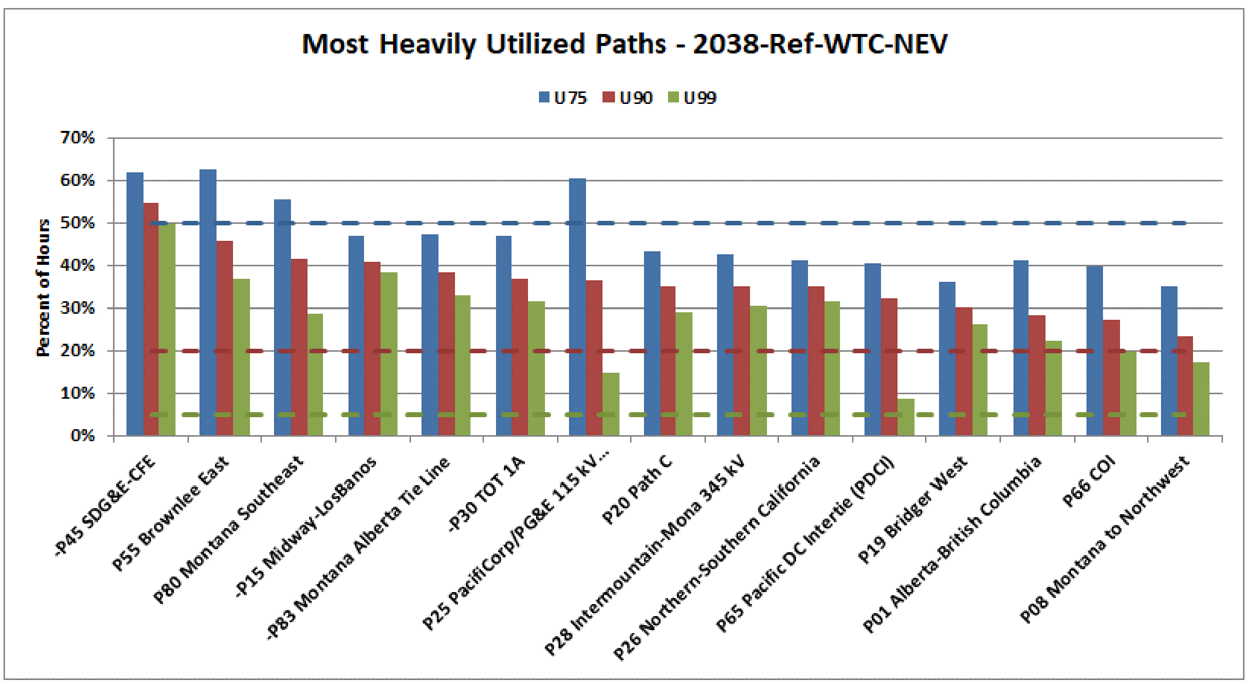


Figure 37: Most Heavily Used Paths – 2038 Reference Case



Commonalities and differences of heavily used paths between SC1 and the Reference Case are shown in Table 7. The list of the most heavily used lines didn't change between SC1 and the Reference Case, but the levels of use did to some extent.

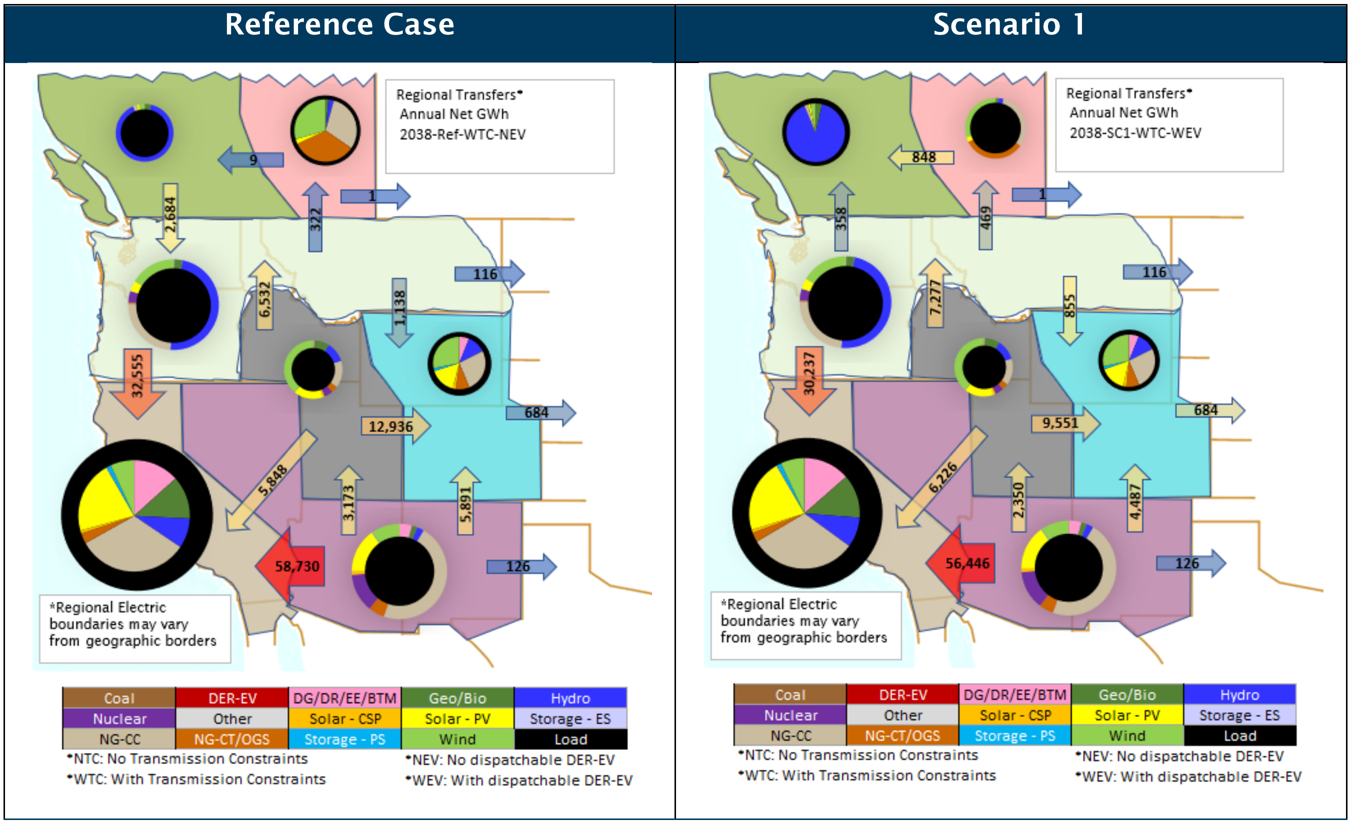
Table 7: Correlation of Heavily Used Paths to Regions – Scenario 1

Path	Region(s)
P01 Alberta-British Columbia	Alberta, British Columbia
P08 Montana to Northwest	Northwest
P15 Midway-Los Banos	California
P19 Bridger West	Basin, Rocky Mountain
P20 Path C	Basin, Northwest
P25 PacifiCorp/PG&E 115 kV Interconnection	California, Northwest
P26 Northern-Southern California	California
P28 Intermountain-Mona 345 kV	Basin
P30 TOT 1A	Basin, Rocky Mountain
P45 SDG&E-CFE	California, Mexico
P55 Brownlee East	Basin, Northwest
P65 Pacific DC Intertie (PDCI)	California, Northwest
P66 COI	California, Northwest
P80 Montana Southeast	Northwest
P83 Montana Alberta Tie Line	Alberta, Northwest
Heavily Used in the Reference Case Only	
Heavily Used in Scenario 1 Only	
Heavily Used in both Scenario 1 and the 2038 Reference Case	

As Table 7 shows, the most heavily used paths identified for SC1 are the same as those identified for the Reference Case. Path use in SC1 is generally slightly less than the Reference Case due to lower load levels, except for Paths 25, 45, and 55. Path use for paths 25 and 45 increase slightly as the dependence on these paths for energy transfers to Southern California increase at evening peak demand when energy production from solar declines. Path use for Path 55 increases slightly as energy production from the Southwest and Basis regions increase.

A comparison of regional transfers of annual energy is shown in Figure 38.

Figure 38: Path Flow Comparison of Scenario 1 to 2038 Reference Case

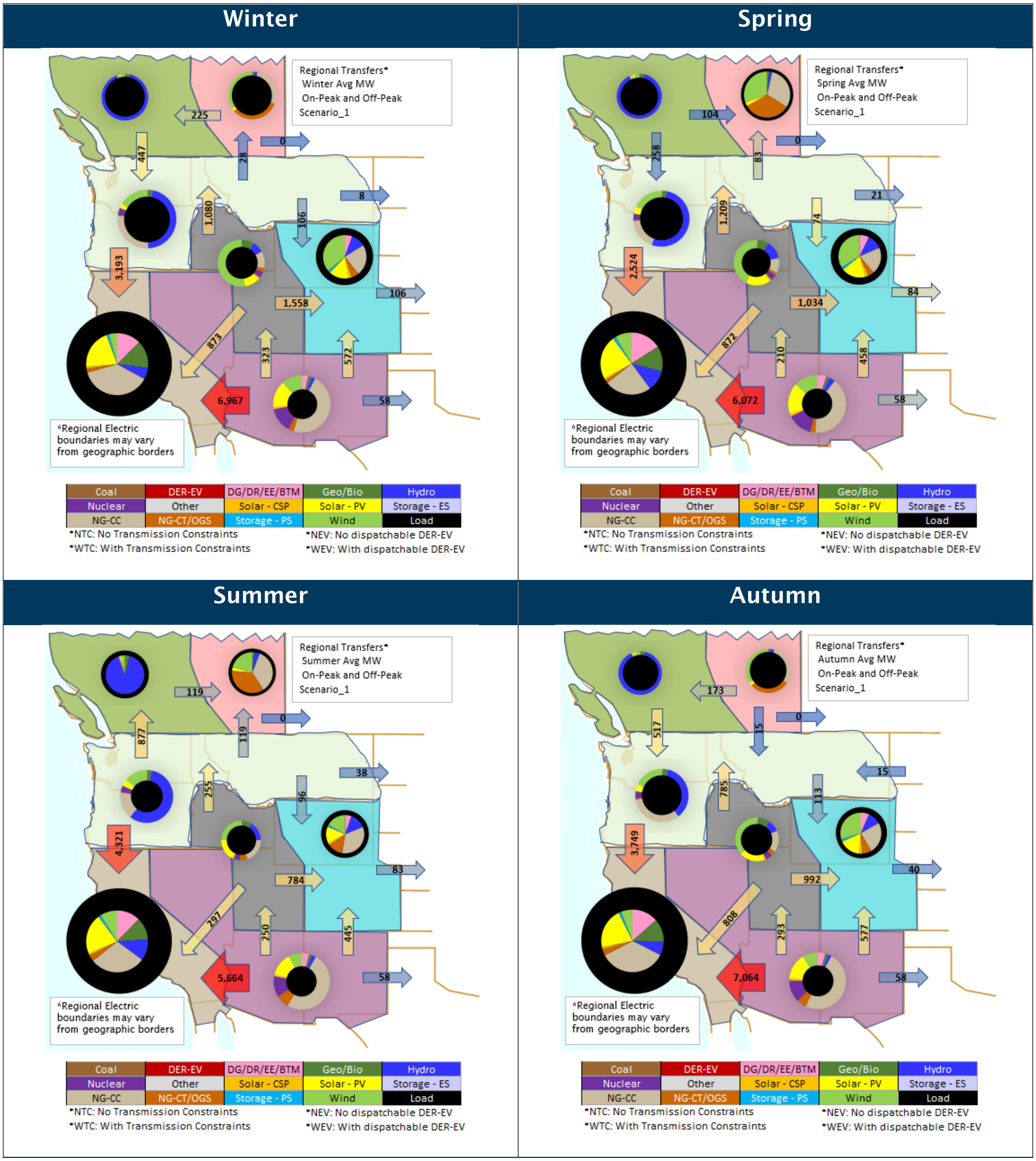


The regional transfers of annual energy in SC1 are slightly less overall than that in the Reference Case since SC1 has slightly less load levels than the Reference Case. Dependence on the Southwest for energy exports decreased slightly due to decreased energy production from gas fired resources. Imports to Colorado decreased with lower load levels. Exports from British Columbia to the Northwest decreased with lower load levels in the western states. Exports from the Basin to California and the Northwest increased slightly, mainly due to less energy production from gas fired resources which changed the overall energy production mix in the Western Interconnection (e.g., ratio of gas fired to renewables) which, in turn, slightly changes the power flows across the Western Interconnection overall.

SC1: Seasonal Variations

The seasonal variations of path flows for SC1 are shown in Figure 39 and do not differ notably from what resulted for the Reference Case other than small resulting flow decreases due to lower load levels in SC1 than the Reference Case.

Figure 39: Seasonal Path Flow Variations for Scenario 1



California represents roughly 30% of the total seasonal load energy requirement and the magnitudes of energy transfer from the Northwest and the Southwest to California are inversely seasonally related.

SC1: Key Scenario Questions and Takeaways

- How might customer and other behind the meter energy products and services be captured for planning purposes?
  The NREL Demand-Side Scenario characterized as Reference Adoption and Slow Technology Advancement was used to capture the factors identified in this question. The Reference for customer adoption assumes the least incremental change and limited improvements in cost and performance. For the NREL EFS, and by extension this study, the focus was on what could be classified as energy transition. In this regard, electrification is defined as the substitution of electricity for direct combustion of non-electricity-based fuels (e.g., gasoline and natural gas) used to provide similar services. In other words, the energy transition focus was on electric technologies that can be used to replace those that are existing and non-electric — e.g., electric vehicles for internal combustion engine vehicles, heat pumps for natural gas space heating, and electric induction furnaces for fuel-fired industrial furnaces. Yet to-be-developed electric-based technologies were not included in the analysis. [1] *Further details on modeling assumptions can be found in Appendix D.*
  a. What key categories of energy services and products might be selected for scale?
     Electric vehicles, air-source heat pumps (ASHP), and heat pump water heaters as identified in the NREL EFS. [1]
- What potential reliability risks should identified/analyzed if the world of Scenario 1 is realized?
  a. *Same reliability risks as observed for the Reference Case.*
  b. *Customer choice models in this study were limited to those that represent a potential for energy transition, (e.g., fuel switching away from fossil fuels). Products and services that may be available to customers in the future and how to model them need to be better understood.*
- Since the load profile of SC1 is comparable to the Reference Case and since the SCRP is comparable to the RCCRP (except for the addition of dispatchable DER-EV), key takeaways from the Reference Case apply to SC1 as well.
- The addition of dispatchable DER in the form of electrical vehicle storage (dispatchable DER-EV) modeled within SC1 effectively reduced unserved load at evening peak. While dispatchable DER-EV represents less than 2% of the total energy production of the resource portfolio, it effectively reduces unserved load at lower levels of electrification. Dispatchable DER-EV is shown to be less effective at higher electrification load levels because the overall resource flexibility of the SCRP is quickly exhausted at hourly demand levels above the 180 GW threshold.
- The NREL demand-side load profiles selected for SC1 and SC3 assume low levels of customer adoption of evolving new DER and BTM energy services. It is further assumed in these selected profiles that expanded use of new energy options won't significantly occur until after the year 2038.

Scenario 2 (SC2)

SC2 is characterized in the Scenario Matrix as having open markets with high levels of customer choice and adoption of new service options. The following lists assumptions from the narratives for SC2 in the Scenario Matrix. [16] Following each assumption are descriptions of the modeling approaches used:

- Regulations are open and flexible to allow a range of energy service options.
  Captured primarily by assumptions about technology advancement in terms of cost and performance. In other words, how will regulations affect technology innovation and customer adoption? In the case of this scenario, the NREL Rapid assumptions for technology advancement is chosen. The Rapid Advancement Case is intended to reflect a rapid increase in technology trends beyond current levels in terms of innovation, research and development, deployment, cost reductions, and performance improvements by 2050. [1]
- Customers are willing to try new energy service options with varied levels of success and a belief in receiving benefits over costs.
  The NREL High trajectory for end-use Technology Adoption was used. The High scenario assumes a more favorable set of conditions for electrification—including a combination of technology breakthroughs, policy support, and underlying societal and behavioral shifts that yield an electrification transition. As a result, the High scenario reflects an increase in the degree of electrification across transportation, commercial, residential, and industrial sectors. The High trajectory assumes that the electric technologies generally experience earlier saturation. [1] While expanded use of new energy options captured in the demand-side load profiles occur modestly prior to 2038, significant acceleration does not occur until after 2038.
- The bulk transmission system is maintained as reliability is increasingly met by distributed energy options.
  SC2 is modeled with the same reliability requirements as that of the 2028 ADS PCM including transmission path limits, resource flexibility, and other operational security constraints. Dispatchable DER-EV is less effective at higher electrification load levels because the overall resource flexibility of the SCRP is quickly exhausted at hourly demand levels above the 180 GW threshold. To satisfy this assertion, the SCRP for SC2 will need to have an adequate mix of resources that can provide resource flexibility at evening peak demand and the commitment thresholds for resource flexibility will need to be adequately adjusted.

SC2: Modeling Components

The modeling components below were selected based on the narrative for SC2 to the extent that changes from that of the Reference Case were needed to capture the intentions behind this scenario narrative. While it is not possible to match all parts of the narrative with an equivalent quantitative measure, the learning process involved in scenario modeling advances with additional iterations, as should the modeling capabilities.

Load Models: Derived from the NREL Demand-Side Scenario [13] with High Customer Adoption of new service options and with Moderate Technology Advancement assumptions as further described in Appendix D under "Load Models."

Generation Resource Portfolio: The Scenarios Candidate Resource Portfolio (SCRP) is derived from the RCCRP with the addition of dispatchable DER-EV from the NREL Demand-Side Scenario used for SCENARIO 1 (as further described in Appendix D under "Generation Resource Models."

Transmission Topology: The transmission topology is that contained within the 2028 ADS PCM with interface paths monitored as further described in Appendix D under "Transmission Models."

SC2: Load

Unserved load for SC2 was 2,860 GWh across all regions but primarily in the California, Basin and Southwest regions and, to a lesser extent, in the Rocky Mountain region shown in Figure 40. Unserved load in SC2 was substantially larger than the 306 GWh of unserved load that occurred in the 2038 Reference Case, largely due to increased electrification. The occurrence of unserved load in SC2 is like that of the 2038 Reference Case, shown in Figure 41, but is shown to span more regions. SC2 has the highest annual load energy requirement than all the Scenarios. Subsequently, SC2 also has the highest amount of unserved load, much more so than all the other scenarios and even the Reference Case, which doesn't have dispatchable DER-EV, but that will be discussed in greater detail later section.

While dispatchable DER-EV effectively at mitigated unserved load in Scenario 1, it was less effective in Scenario 2. Dispatchable DER-EV, within the parameters of the Scenario simulations, was less effective at higher electrification load levels because the overall resource flexibility of the SCRP is quickly exhausted at hourly demand levels above the 180 GW threshold. In the case of SC2, evening peak demand nearly reached 250 GW. These observations are, however, dependent on the amount of resource flexibility committed and available at evening peak demand periods for any given day. If the requirements for resource flexibility were increased in the PCM day-ahead commitment, then the risk of unserved load would be reduced, but at a higher overall commitment cost.

Figure 40: Unserved Load for 2038 Scenario 2 WTC WEV

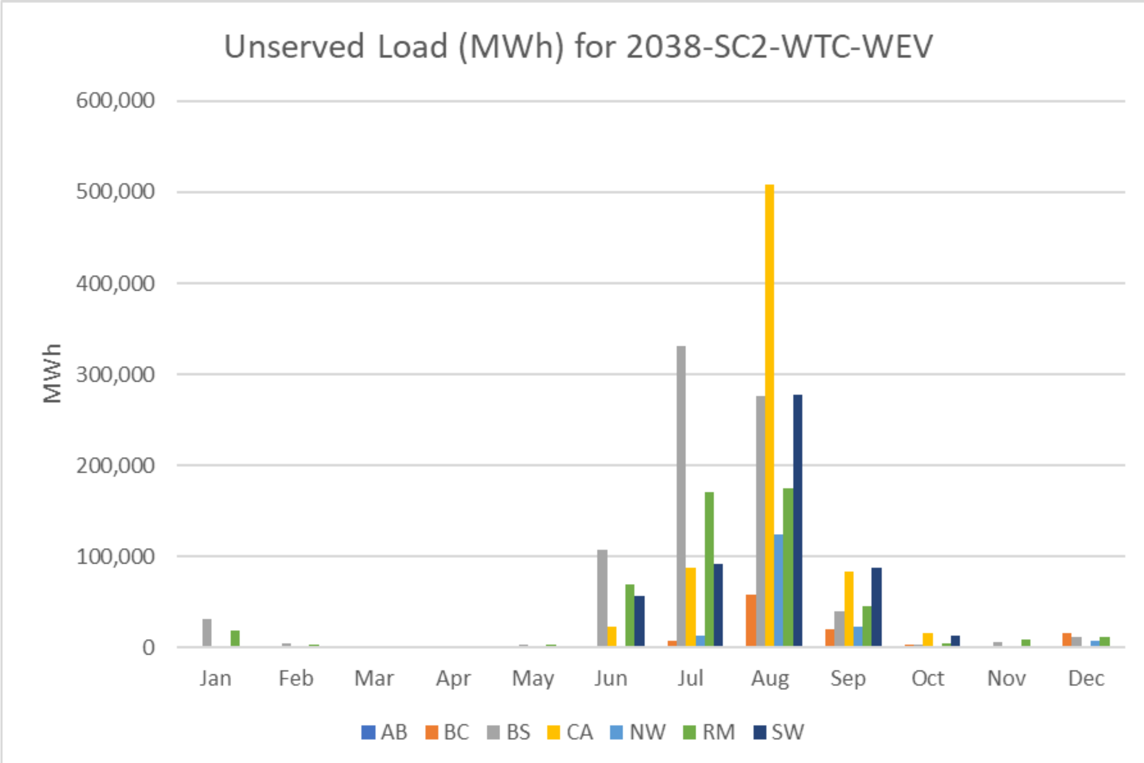
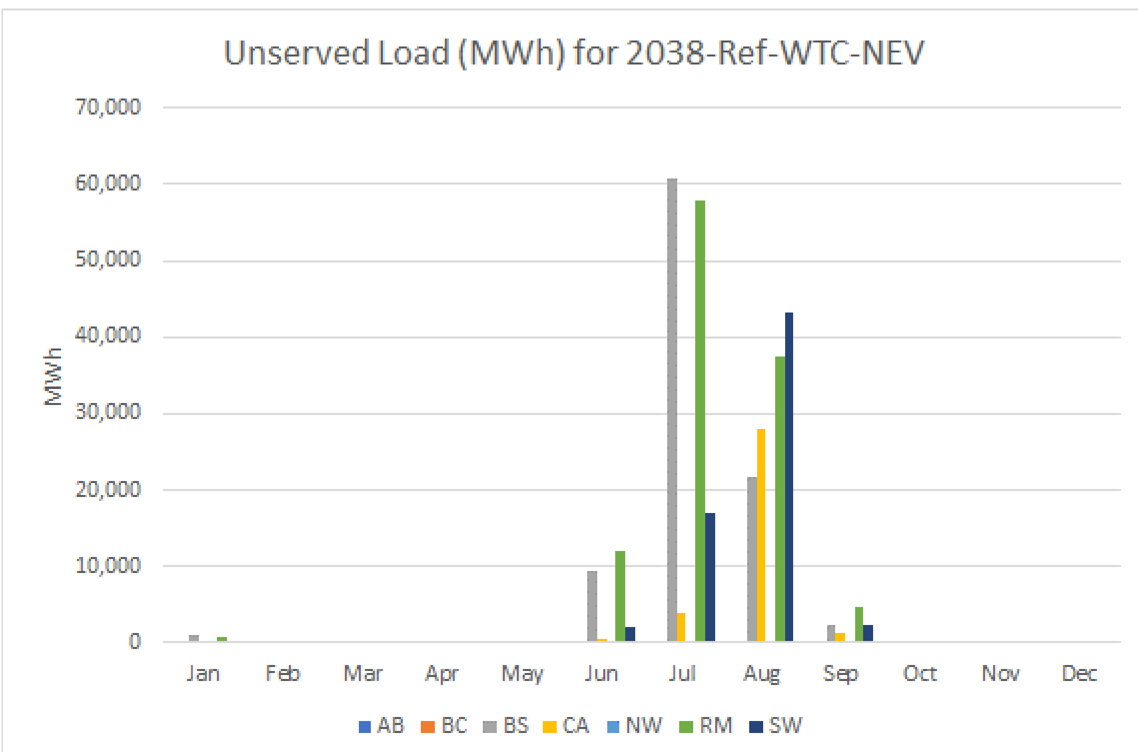
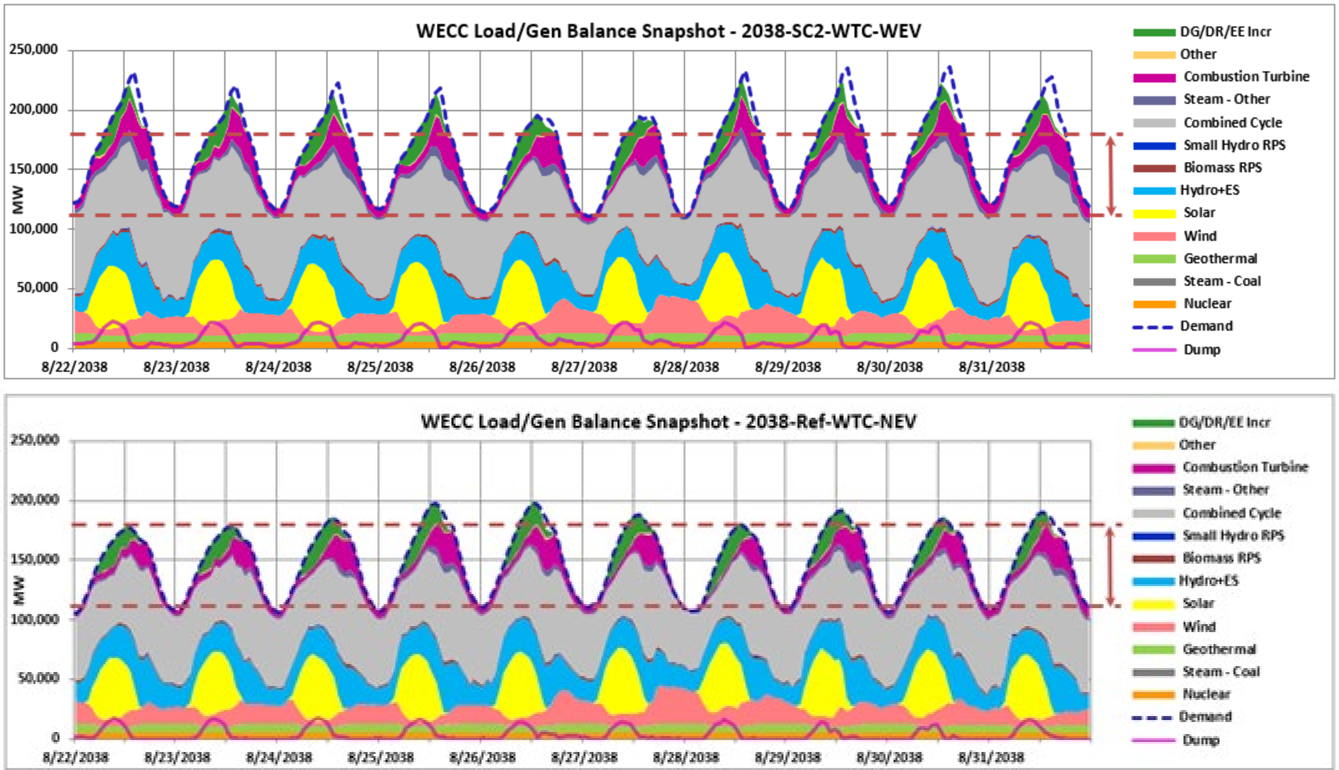


Figure 41: Unserved Load for 2038 Reference Case WTC NEV



The load to generation balance between SC2 and the Reference Case is shown in Figure 42.

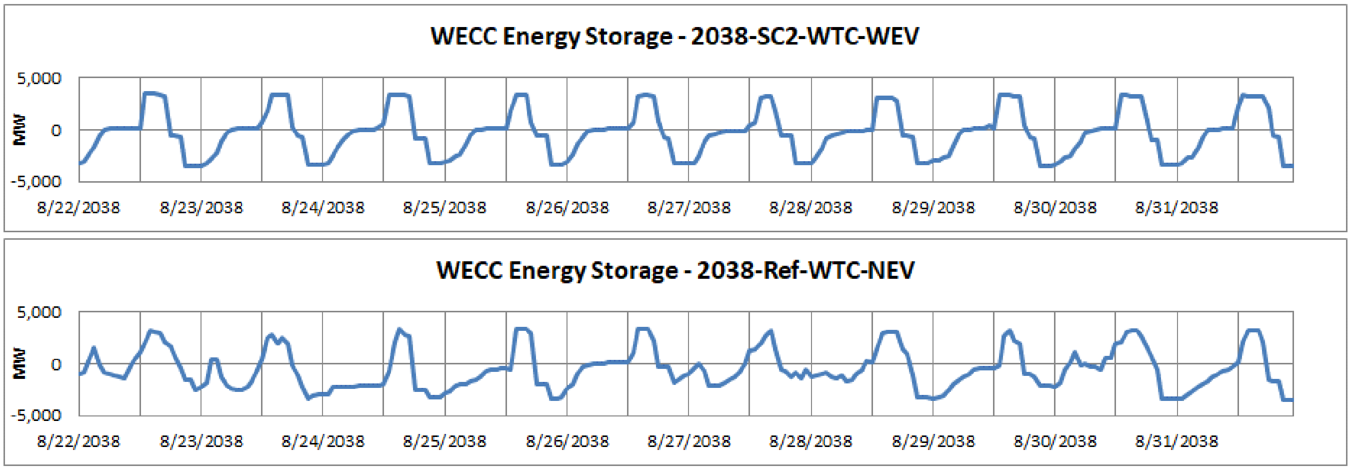
Figure 42: Load/Gen Comparison - 2038 Scenario 2 to 2038 Reference Case



As Figure 42 shows, evening peak demand significantly increases from that of the Reference Case, as does the amount of unserved load. The diurnal shape of load demand is more extreme than that of the Reference Case, which increases the operational challenges to commit and dispatch resources, especially with high levels of solar when load demand is low and low levels of solar at evening peak demand (when ELCC of solar is poor). As a result, the dependence on resource flexibility increases (e.g., gas fired generation and electrical storage).

A comparison of the diurnal shapes of electrical storage between the 2038 Reference Case and the 2028 ADS PCM is shown in Figure 43.

Figure 43: Electrical Storage Comparison - 2038 Scenario 2 to 2038 Reference Case



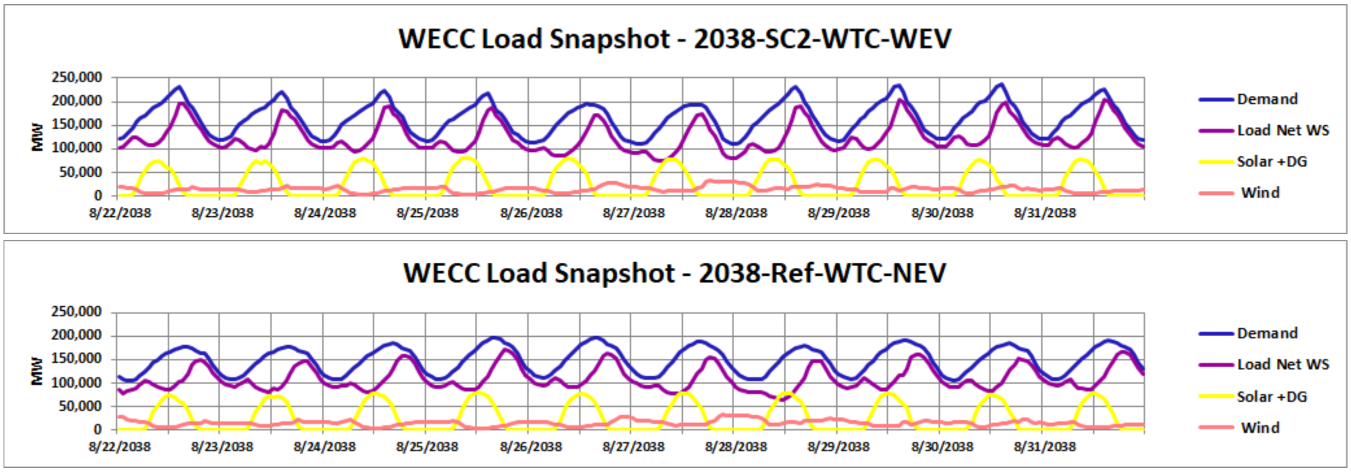
As Figure 43 shows, the daily shape of electrical storage energy dispatch (charging and dispatch) is more uniform in SC2 than in the Reference Case due to the use of electrical storage at its maximum available capacity at evening peak load demand. The maximum electrical storage dispatch in the Reference Case is roughly 4,000 MWs and produces a distinct plateau when ELCC is saturated. The width of the plateau is representative of the duration at which electrical storage can supply energy at this maximum. If the width of this plateau were wider (e.g., more electrical storage with longer dispatch durations across evening peak), then unserved load would reduce to zero.

Optimizing charging and dispatch times of electrical storage to extend the duration that is available for resource flexibility across the entire evening peak demand period would increase storage effectiveness in reducing the instances of unserved load.

Follow-up studies to investigate the effects of increased electrical storage and optimal diurnal times for charging and dispatch would clarify the potential of electrical storage to mitigate the risks of unserved load at evening peak demand more specifically. In practice, there may be opportunities to accomplished this through policy, market mechanisms, and/or demand-side technology advancements.

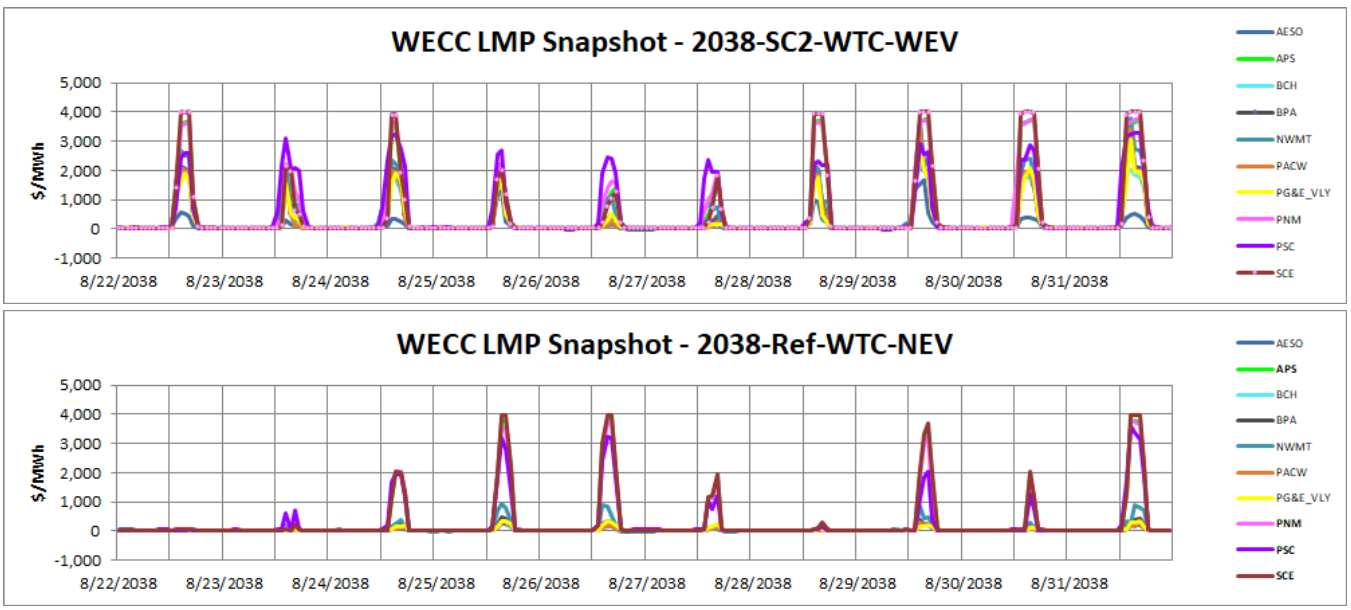
The effect of variable generation on net load demand for SC2 is shown in Figure 44. The diurnal shapes of net load demand for SC2 are more severe than that of the Reference Case due to larger gross load demand. The dispatch of solar is essentially the same, driving the severity of net load demand for SC2.

Figure 44: Comparison of Net Load – 2038 Scenario 2 to 2038 Reference Case



A comparison of LMPs between SC2 and the Reference Case are shown in Figure 45.

Figure 45: LMP Snapshot Comparison - 2038 Scenario 2 to 2038 Reference Case

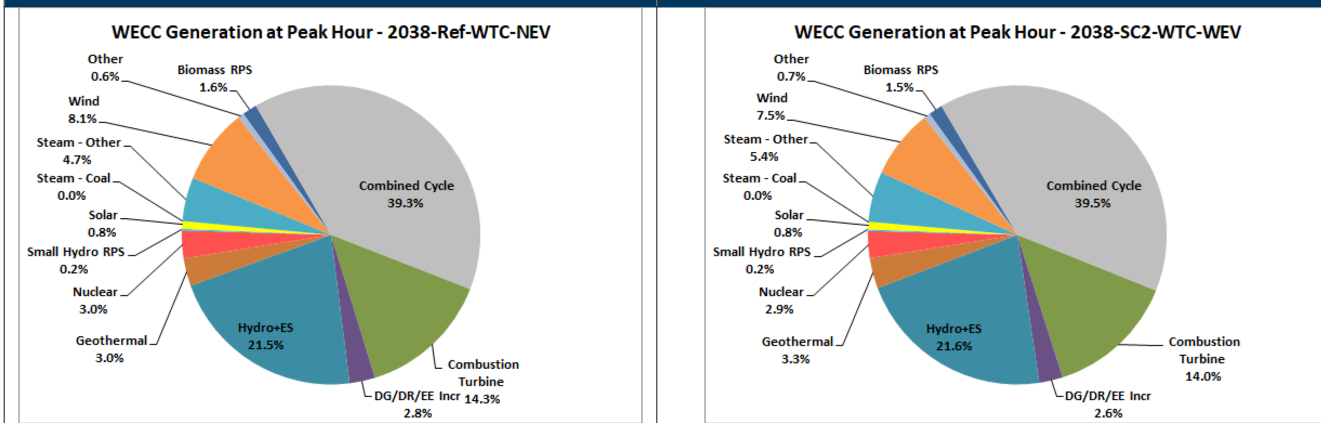


More LMP spikes occurred in SC2 than occurred in the Reference Case across the ten-day period examined and all were above $2000/MWh, with the majority at the maximum of $4000/MWh and coinciding closely with unserved loads that occurred at evening peak demand for all days.

A comparison of generation dispatch at the evening peak hour between SC2 and the Reference Case for the ten-day window being examined is shown in Figure 46.

Figure 46: Generation at Peak Hour Comparison - 2038 Scenario 2 to 2038 Reference Case

2038 Reference Case	2038 SC2-WTC-WEV



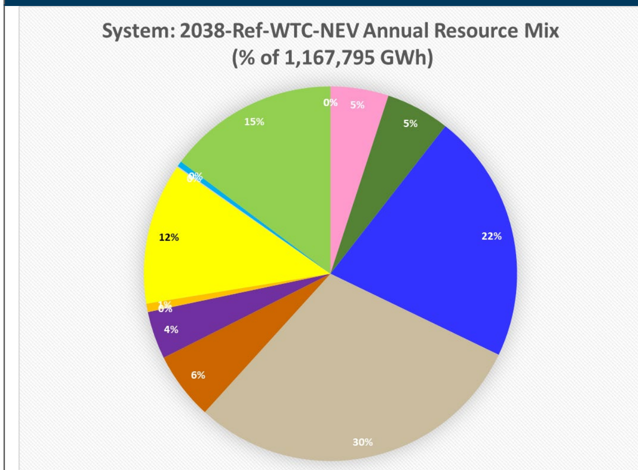
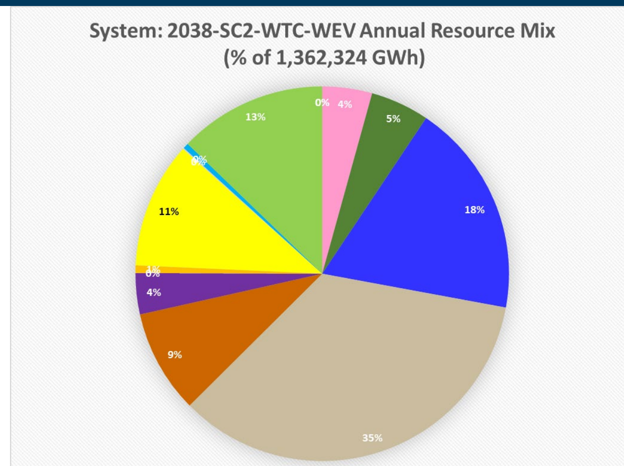
While the SCRP has more than enough resource adequacy from an annual energy production standpoint, it doesn't have enough resource flexibility when evening peak demand exceeds a 180 GW upper bound observed in the Reference Case. Further study is needed to fully quantify an optimal portfolio mix required to meet the needs of demand levels such as those observed in SC2. Overall, it would be beneficial to study different ensembles of generation portfolio mixes (e.g., different levels of resource flexibility) at load levels like that of SC2.

While the SCRPs for SC1 and SC3 were adequate to meet the resource flexibility needs of SC1 and SC3, the SCRPs for SC2 and SC4 fell short in meeting the resource flexibility needs of SC2 and SC4. In the SCRPs for all Scenarios, energy production from solar represented roughly 12% of the total from the SCRPs. Most of that energy production from solar occurs when demand is low, while solar provided less than 1% of the dispatch at evening peak when unserved load occurred. Gas fired generation and DG/DR/EE/BTM provided 58% of the dispatch at evening peak for SC1 and SC3, when little unserved load occurred, and 56% of the dispatch at evening peak for SC2 and SC4, with substantial unserved load. This represents a 2% difference in dispatch from flexible resources for SC1 and SC3 relative to SC2 and SC4. This observation suggests that a 58% threshold of resource flexibility at evening peak demand, within the simulation parameters of the Scenarios, is required to avoid the occurrence of unserved load. Unserved load occurred for SC1 and SC3 when evening peak demand exceeded 180 GW. As discussed previously, this 180 GW threshold was observed across the Scenarios and Reference Case and is partly dependent on the extent that resources with higher levels of resource flexibility are available and committed for evening peak demand and the thresholds at which these resources are committed. Peak demand for SC2, at maximum unserved load, was 225 GW. Roughly 131 GW of resource flexibility would be required to maintain a 58% threshold for SC2, a difference of approximately 4.5 GW.

SC2: Generation

The annual resource energy production mix for SC2 as compared to the Reference Case is shown in Figure 47.

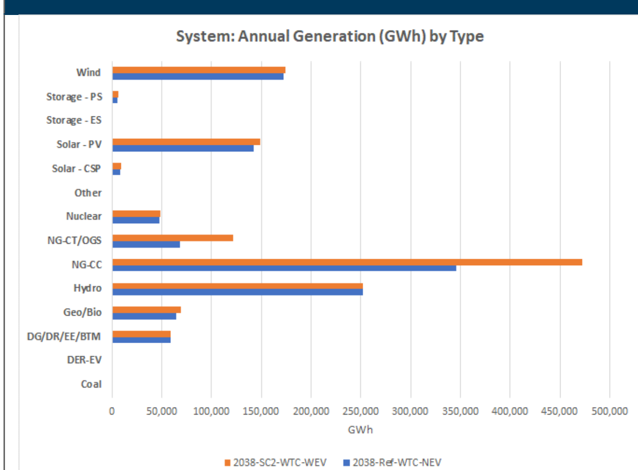
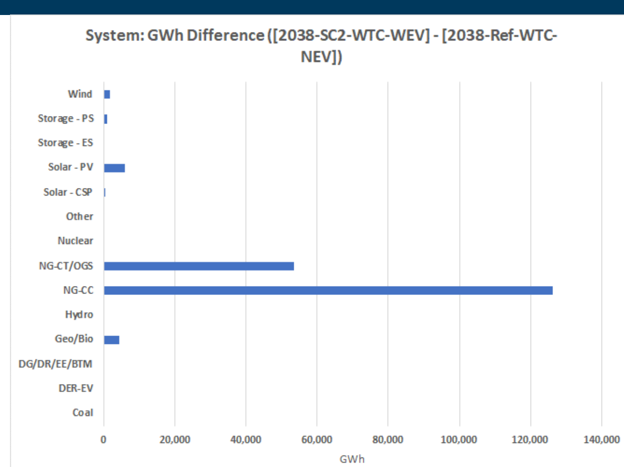
Figure 47: Comparison of Annual Resource Energy Production (GWh) – Scenario 2 to 2038 Reference Case

Reference Case	Scenario 2
	

Coal	DER-EV	DG/DR/EE/BTM	Geo/Bio	Hydro
Nuclear	Other	Solar – CSP	Solar - PV	Storage - ES
NG-CC	NG-CT/OGS	Storage – PS	Wind	

The change in energy production between SC2 and the Reference Case is shown in Figure 48.

Figure 48: Scenario 2 – Resource Additions/Displacements by Type (GWh)

Generation Comparison	Added/Displaced Generation
	

As shown above, most of the change in energy production between SC2 and the Reference Case was an increase in gas fired generation due to higher load levels in SC2. There was a slight increase in energy production from resources other than gas, attributable to less energy spillage due to slightly higher levels of load for SC2 than for the Reference Case.

SC2: Inter-Regional

The most heavily used transmission paths for SC1 are shown in Figure 49 with those in the Reference Case shown in Figure 50.

Figure 49: Most Heavily Used Paths – Scenario 2

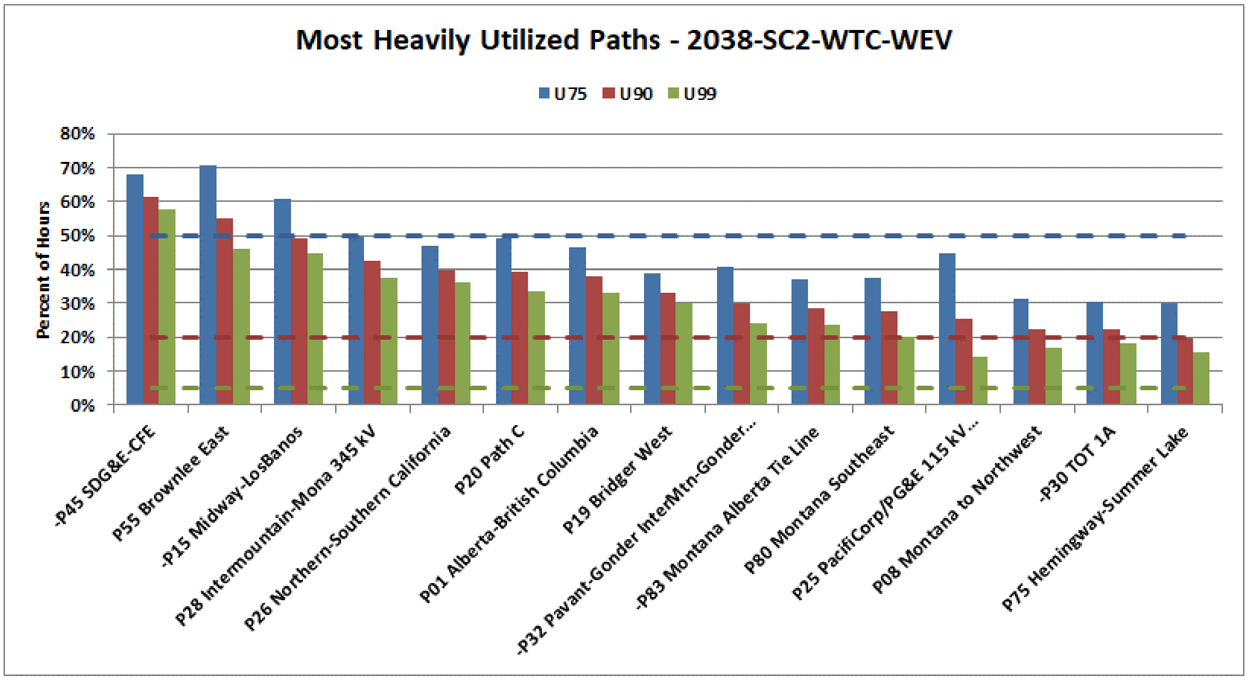
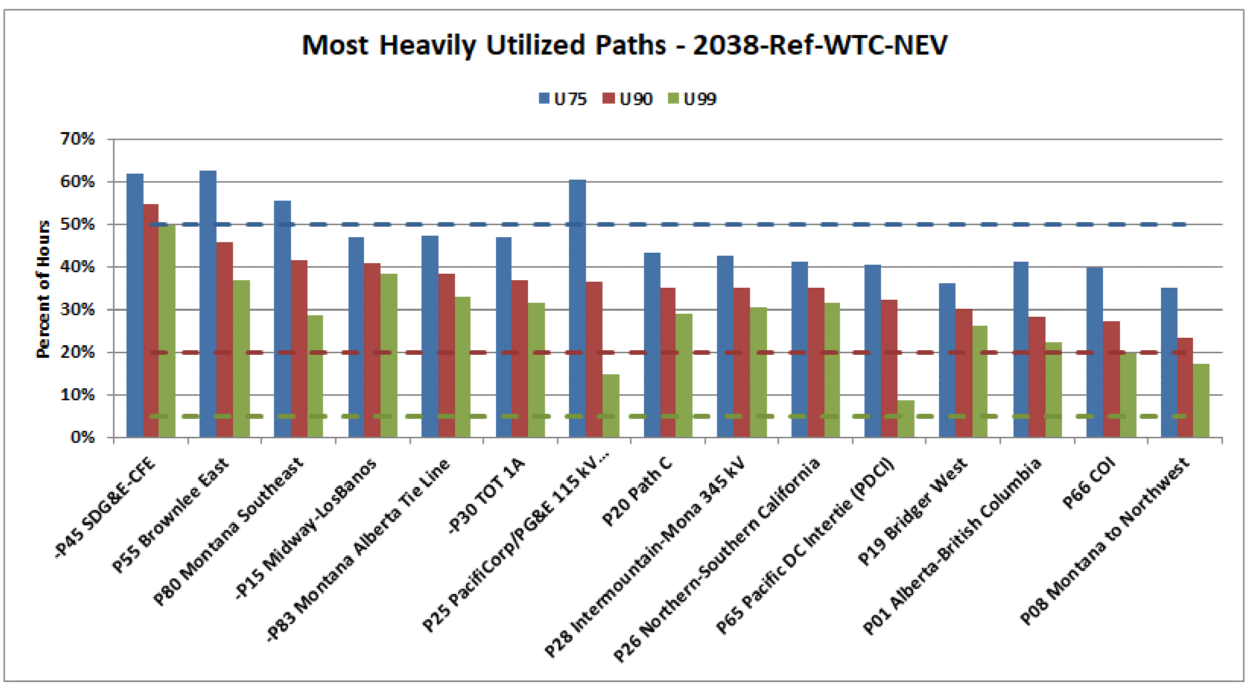


Figure 50: Most Heavily Used Paths – 2038 Reference Case



Commonality of heavily used paths between SC2 and the Reference Case is shown in Table 8.

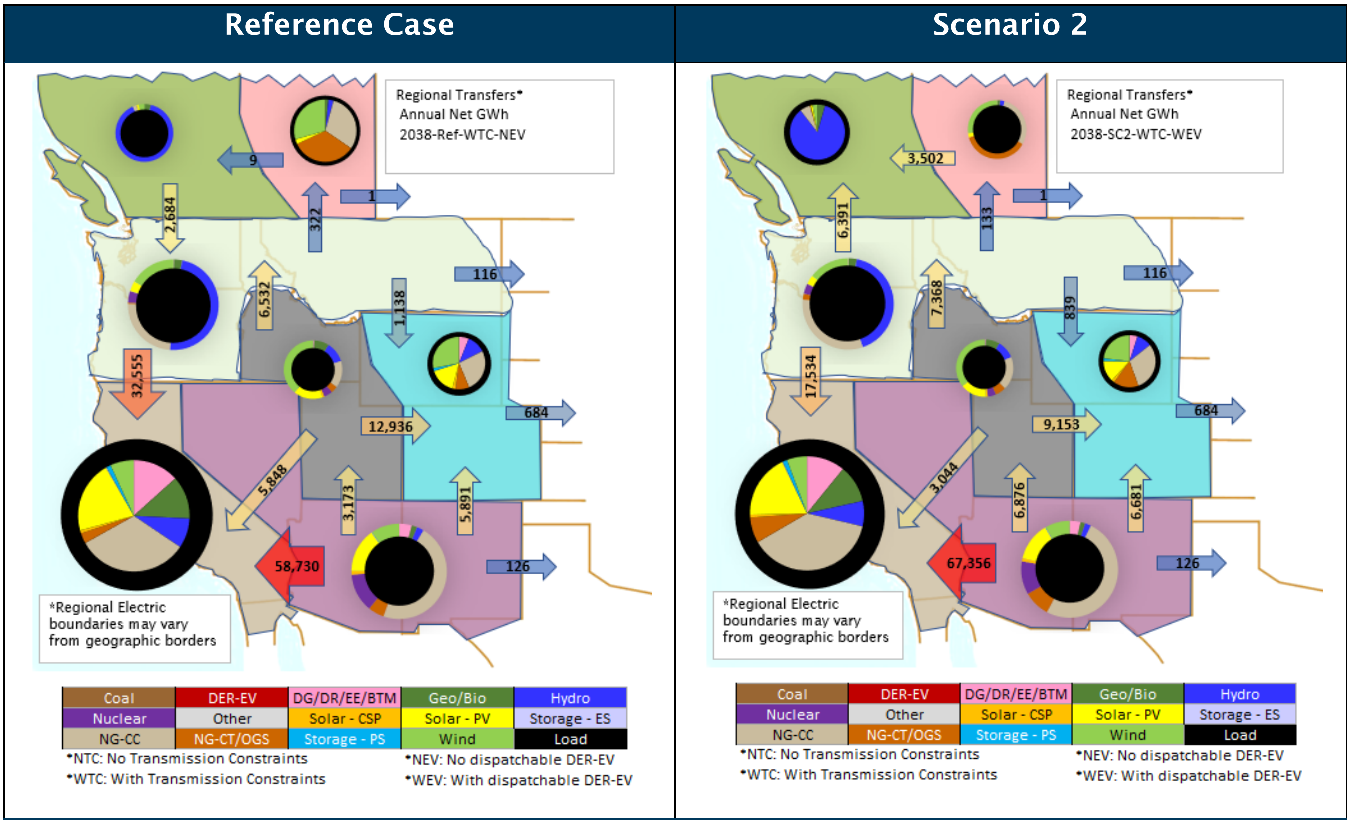
Table 8: Correlation of Heavily Used Paths to Regions – Scenario 2

Path	Region(s)
P01 Alberta-British Columbia	Alberta, British Columbia
P08 Montana to Northwest	Northwest
P15 Midway-LosBanos	California
P19 Bridger West	Basin, Rocky Mountain
P20 Path C	Basin, Northwest
P25 PacifiCorp/PG&E 115 kV Interconnection	California, Northwest
P26 Northern-Southern California	California
P28 Intermountain-Mona 345 kV	Basin
P30 TOT 1A	Basin, Rocky Mountain
P32 Pavant-Gonder InterMtn-Gonder 230 kV	Basin
P45 SDG&E-CFE	California, Mexico
P55 Brownlee East	Basin, Northwest
P65 Pacific DC Intertie (PDCI)	California, Northwest
P66 COI	California, Northwest
P75 Hemingway-Summer Lake	Northwest
P80 Montana Southeast	Northwest
P83 Montana Alberta Tie Line	Alberta, Northwest
Heavily Used in the Reference Case Only	
Heavily Used in Scenario 2 Only	
Heavily Used in both Scenario 2 and the 2038 Reference Case	

As shown above, , the most heavily used paths identified for SC2 are the same as those identified for the Reference Case, with the exception of Paths 32 and 75 in SC2 and Paths 65 and 66 in the Reference Case. Paths in SC2 have slightly heavier use than the Reference Case in general but with less power flowing from the Northwest to California.

A comparison of regional transfers of annual energy is shown in Figure 51.

Figure 51: Path Flow Comparison of Scenario 2 to 2038 Reference Case



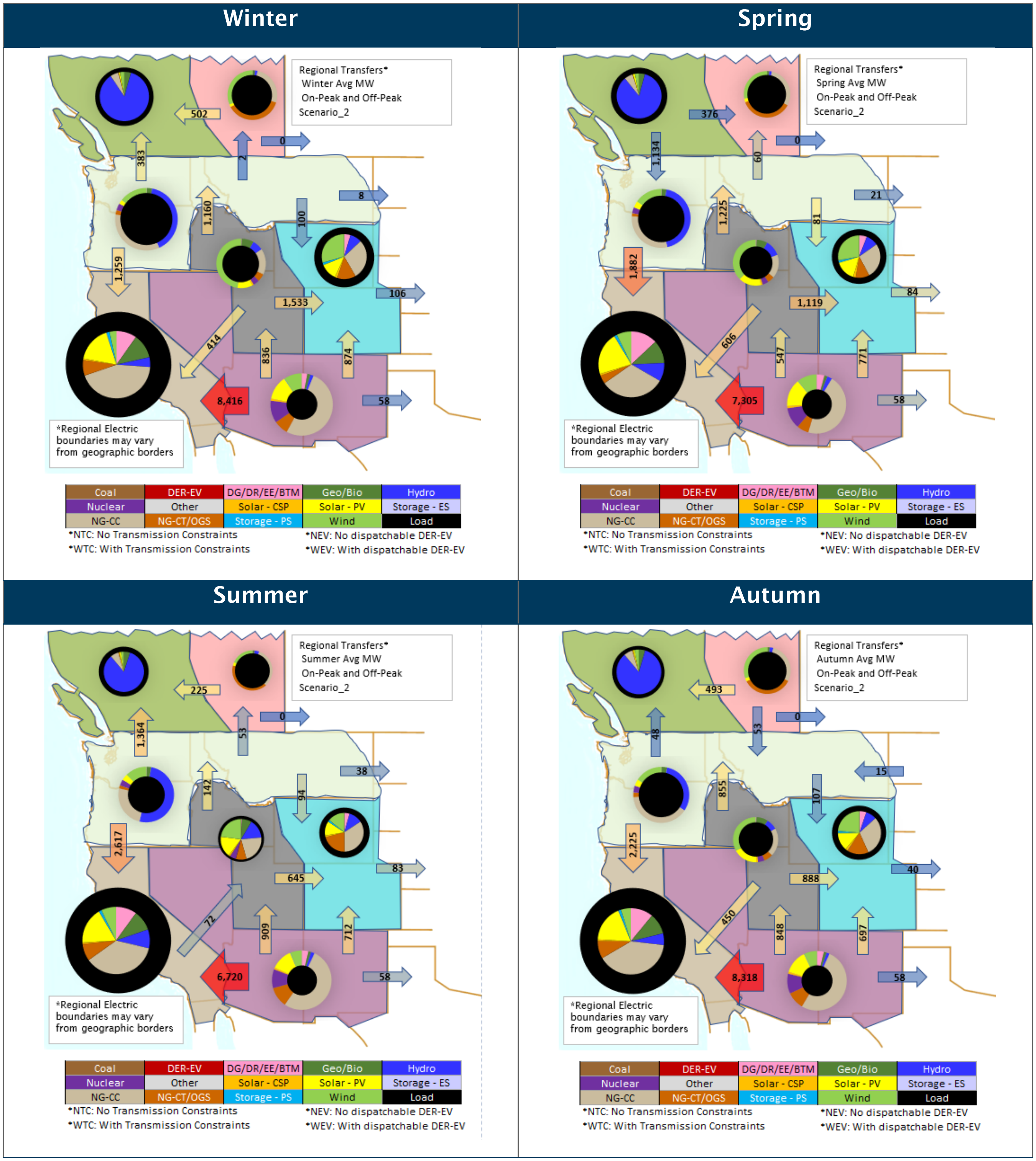
As shown above, transfers from the Northwest to California drop with higher load levels in the Northwest and British Columbia shifting the power flows from the Northwest to stay in the Northwest and British Columbia. Energy transfers from the Southwest to California increase, compensating for decreased flows from the Northwest to California. Exports from the Southwest to the Basin and Rocky Mountain Regions also increase slightly with increased energy production from gas fired resources in the Southwest. Imports into the Rocky Mountain region decrease, however, as energy production from gas fired generation in that region increases. In general, dependence on the Southwest for energy production from gas fired resources increases as load levels increase which results in higher levels of export and transmission use out of the Southwest. Conversely, transmission use generally goes down for the rest of the Western Interconnection, with a few exceptions, as energy production across the Western Interconnection increases, loads are increasing served by increased local gas fired generation.

SC2: Seasonal Variations

The seasonal variations of path flows for SC2 are shown in Figure 52 and, when compared to that of the Reference Case, further illustrate a greater dependence on the Southwest and the Basin for energy production and dispatch, especially during winter months, while transfers from the Northwest to

California decrease as load levels in the Northwest increase and the surplus of generation in the Northwest decreases.

Figure 52: Seasonal Path Flow Variations for Scenario 2



As Figure 52 shows, California has the largest seasonal load energy requirements representing approximately 34% of the total annual system load energy requirement, while California's energy production represents 30% of that of the system; California is a net annual importer of energy across all seasons.

Energy transfers from the Northwest to California are greatest during summer when load in California is highest and there is a surplus of hydro energy production in the Northwest. Energy transfers from the Northwest to California are least during winter when load in California and hydro energy production in the Northwest are less than in summer, and load in the Northwest is highest.

Energy transfers from the Southwest to California are greatest during the winter when energy transfers from the Northwest are at their least, while energy transfers from the Southwest to California are least in summer when energy transfers from the Northwest are at their greatest. In this regard, the energy transfers from the Northwest and the Southwest to California are inversely seasonally related.

Energy transfers occur from the Basin to California across all seasons (when energy production in the Basin is at a surplus to load) except in summer where California is exporting energy to the Basin (when energy production in the Basin is at a deficit to load).

SC2: Key Scenario Questions and Takeaways

In the WECC narrative for SC2, some key questions were raised based on the core ideas and arguments in the future the scenario. Answers to and insights on those questions gained from this analysis are provided below:

1. As distributed resources, presence both in front of and behind the meter become significant as integrated load serving resources.
    a. What infrastructure changes and upgrades in both the BPS and distribution systems might be needed for system integration, co-optimization, and coordinated operations?
    Demand-side management coupled with electrical storage offers the greatest potential on the distribution side to mitigate risks from a highly electrified future, especially considering increased penetrations of solar that have low ELCC at evening peak. Accelerated coupling of electrical storage with solar and wind (hybrid systems) has great potential. How these opportunities are manifesting from policy, economics, markets, industry, and/or customer demand warrants further study.
    b. Where are these changes and upgrades needed? What would they cost, who would pay for them, and how would their costs be allocated among customers?
    These changes could occur from policy, markets, industry, and/or customer demand drivers. Ultimately, reliability assurance, economics, and uncertainty challenges will need to be resolved. Will the benefits outweigh the costs? Uncertainty is probably the biggest hindrance to change.

As with solar PV, however, momentum behind adoption can rapidly increase as uncertainty and economics improve.

c. What unique changes would be needed to integrate behind-the-meter (BTM) residential and small business self-generation?
Demand-side management coupled with electrical storage to shave load demand would probably be the most effective measure of integration. Rate design would probably also need to adapt.

d. What timeline would the changes and upgrades involve, and how would states and provinces differ in their rates of adoption/integration?
Broadened electrification of load and the trend toward electric vehicles are already well underway. Continued acceleration of electric vehicle adoption in the transportation sector will dramatically increase total electricity demand. The transportation sector currently accounts for less than 1% of electricity demand but accounts for nearly 30% of total energy consumption in the U.S. [1] *The transitioning of the transportation sector to EV could have a monumental impact on the BPS. Whether BPS planners and operators are adequately ready to respond to this growth is uncertain. Managing electric vehicle charging will require new infrastructure buildouts, adding deployment time. For BPS planners, the challenges of electrification load growth are already manifesting. Demand response measures represent the most immediately available tool that can be deployed, but their implementation will likely require a combination of policy, market, industry, and consumer sector support.*

2. How might the value and profiles of customer and other BTM energy products and services be captured for planning purposes? What key categories might be selected because they can be aggregated to support system capacity?
More work needs to be done to better understand consumer choice models and how they may evolve in relation to technology advancement and consumer adoption. Accelerated growth of vehicle electrification could have a monumental impact on the grid. The need to better understand and plan for this growth is clear, and immediate.

3. How might the value of reliability services from the bulk transmission system change as more distributed resources are used to meet reliability standards within utility distribution systems? On what basis would that value be determined?
Based on this study, the biggest value that DER offers with respect to reliability assurance, is as a tool to shave evening peak demand as part of an overall demand-side management strategy. The ability of the BPS to serve load safely and economically without interruption will be the ultimate measure of reliability. Conversely, unserved load is a measure of system inadequacy. The extent to which DER can be used to mitigate the risk of unserved load at evening peak is an important measure of its value.

4. If utility rates can cover the costs of prematurely retired generation, should those costs be allocated to the replacing resources? If not, where should those costs go and how should they be included in planning analyses?
This question cannot be answered by this study. It has, however, been addressed in the industry and

public forums and arguably settled on a case-by-case basis. Case-by-case outcomes will depend on several factors including whether the retirements resulted from a policy decision, who owns the assets, and what existing agreements may be in place. For example, recovery of stranded costs tied to assets included in a rate base will likely require agreement through local regulatory authorities and that is structured to be equitable to both the regulated utility and affected consumers.

5. Is there one "crisis conditions" study case request that the SDS might make that incorporates a sudden return of demand in the Western Interconnection when, for any reason, sufficient self-generating customers needed to return to receiving services from the incumbent power suppliers?
   The crisis situation posed in this question is presumed unlikely given the accelerated growth of vehicle electrification and the need that creates for the bulk power system as a continuing supply source. It would be useful, however, to examine how demand-side management and electrical storage could be effectively applied to a high electrification future that includes high solar and how consumer choice models might manifest in this future.

- The annual load requirement of SC2 at roughly 455,000 GWh was nearly 40% higher than that of the Reference Case with most of the increased load occurring at evening peak demand. As a result, the diurnal shape of gross load and net load inclusive of wind and solar for SC2 is much more severe than for the Reference Case.
- The occurrence of unserved load in SC2 at 2,860 GWh was more than 9% greater than that of the Reference Case at 306 GWh.
- Dispatchable DER-EV is less effective at higher electrification load levels because the overall resource flexibility of the SCRP is quickly exhausted at hourly demand levels above the 180 GW threshold. In the case of SC2, evening peak demand nearly reached 250 GW.
- As with all the other Scenarios, the incremental increase or decrease in energy production to track load came from gas fired generation and electrical storage (to a lesser extent). The energy production from other resource types generally remained constant to that of the Reference Case. This further illustrates the dependence on gas fired generation and electrical storage for resource flexibility.
- The diurnal shapes of electrical storage became extremely uniform and predictive in SC2 as the resource flexibility capabilities from electrical storage is used fully. Opportunities may exist, however, to better optimize the resource flexibility of electrical storage by adjusting the charging and dispatch times. This warrants further study.
- Resource flexibility in the generation dispatch mix at evening peak demand for SC2 decreased to 56% of the total portfolio dispatch at 225 GW as compared to 58% for the Reference Case at a total portfolio dispatch of 180 GW. Saturation of resource flexibility occurred for the study simulations at demand levels above 180 GW. Increasing resource flexibility commitment thresholds in the PCM may increase the 180 GW threshold by increasing the number of flexible resources committed and available for dispatch at evening peak, but at a higher production cost.

- Reliance on generation surpluses from the Southwest and Basin regions increases with higher load levels in SC2, as does path use in out of these regions.

Scenario 3 (SC3)

SC3 is characterized in the Scenario Matrix as policy driven by lower costs while maintaining reliability while customer service option choices are restricted. The following lists assumptions from the narratives for SC3. [16] Following each assumption are descriptions of the modeling approaches:

- Regulations are structured to assert appropriate controls over the bulk electric system and to ensure that environmental goals are met, and that community-wide reliability is sustained.
  These regulations, to the extent possible, are captured exogenously in the assumptions about technology advancement in terms of cost, improved efficiencies, and improved operational performance (e.g., resource flexibility, ramping). In other words, how will regulations affect technology innovation and customer adoption? In this scenario, the NREL Moderate assumptions for Technology Advancement is chosen. The Moderate Advancement case is intended to reflect a moderate increase in technology trends beyond current levels with respect to innovation, research and development, deployment, cost reductions, and performance improvements. [1]
- Customer demand for new energy options are constrained to ensure cost sharing and overall system integrity.
  The NREL Reference Scenario for end-use technology adoption was used. The Reference Scenario for Technology Adoption represents a business-as-usual outlook where only incremental changes with respect to electrification occur. In particular, the NREL Reference Scenario includes policies that existed as of 2017. It also excludes any dramatic technological, societal, or behavioral shifts as they relate to the adoption of end-use equipment. It reflects a future in which the rate of adoption of electric technologies roughly follows current trends. As such, it represents an electrification transition that remains in the earliest stages even as of 2050. [1]
- The bulk transmission system is protected and maintained to ensure reliability for the interconnection.
  SC3 is modeled with the same reliability requirements as that of the 2028 ADS PCM including transmission path limits, resource flexibility thresholds, and other operational security constraints.

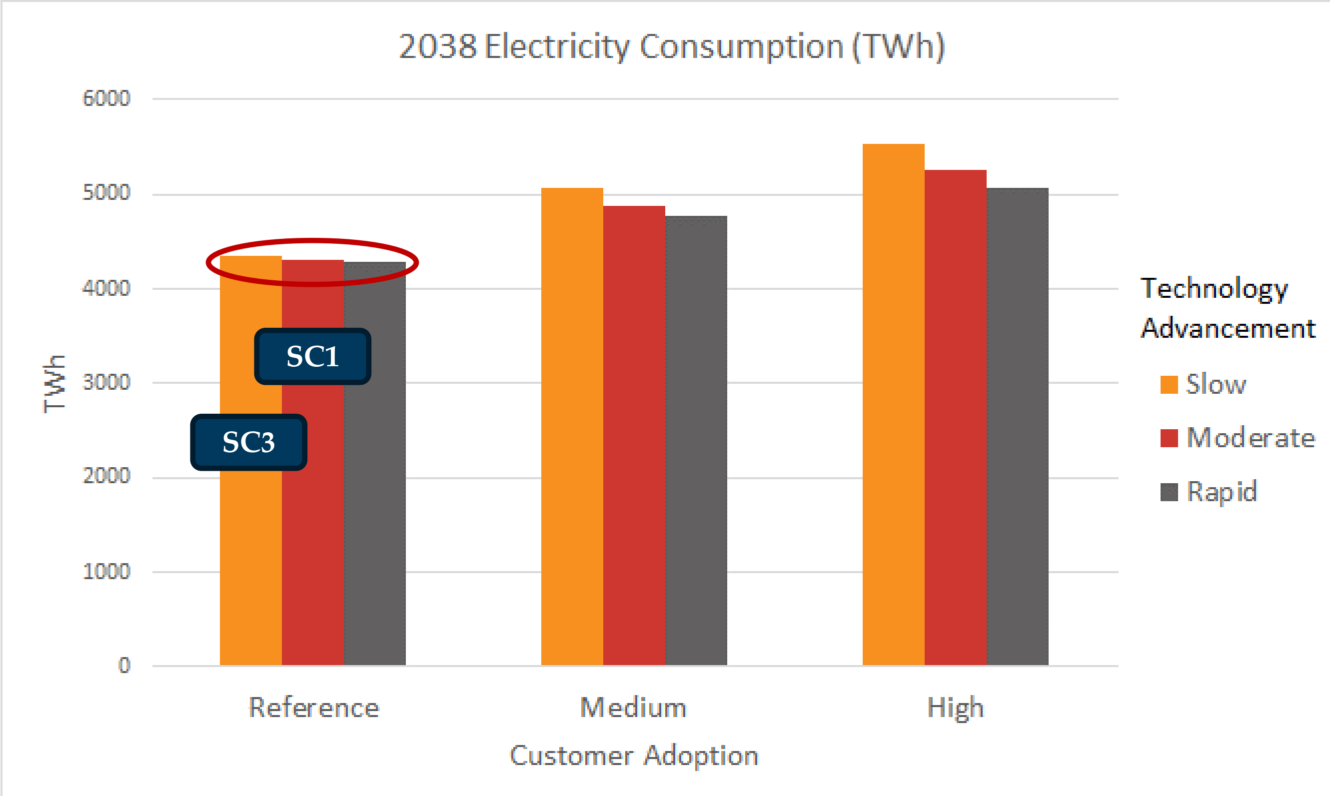
The load profile selected for SC1 is transferred from the Reference Customer Adoption / Moderate Technology Advancement. The load profile selected for SC3 is the Reference Customer Adoption / Slow Technology Advancement. The load profiles selected for SC1 and SC3 both include the Reference trajectory for customer adoption of new consumer choice options as shown in Table 9.

Table 9: NREL Demand-Side Scenarios Matrix [1]

	Slow Technology Advancement	Moderate Technology Advancement	Rapid Technology Advancement
Reference Customer Adoption	Reference Adoption, Slow Technology Advancem SC3	Reference Adoption, Moderate Technology Advancem SC1	Reference Adoption, Rapid Technology Advancement
Medium Customer Adoption	Medium Adoption, Slow Technology Advancement	**Medium Adoption, Moderate Technology Advancem** SC4	Medium Adoption, Rapid Technology Advancement
High Customer Adoption	High Adoption, Slow Technology Advancement	High Adoption, Moderate Technology Advancem SC2	High Adoption, Rapid Technology Advancement

As shown in Figure 53, the Reference trajectory for customer adoption load levels doesn't change significantly as technology advancement changes.

Figure 53: NREL Demand-Side Scenarios -- 2038 Adoption versus Tech Advancement [1]



Since the load levels for SC1 and SC3 are so similar, the results for SC1 and SC3 are almost identical. For that reason, the analysis for SC3 will be like that for SC1. As such, the analysis will not be repeated for SC3. Only the charts and brief discussions for SC3 will be presented.

SC3: Modeling Components

The modeling components below were selected based on the narrative for SC3 to the extent that changes from that of the Reference Case were needed to capture the intentions behind this scenario narrative. While it is not possible to match all parts of the narrative with an equivalent quantitative measure, the learning process involved in scenario modeling advances with additional iterations, as do the modeling capabilities.

Load Models: Derived from the NREL Demand-Side Scenario [13] with the Reference Customer Adoption of new service options and with Slow Technology Advancement assumptions as further described in Appendix D under "Load Models."

Generation Resource Portfolio: The Scenarios Candidate Resource Portfolio (SCRP) is derived from the RCCRP with the addition of dispatchable DER-EV (from the NREL Demand-Side Scenario used for SC3 as further described in Appendix D under "Generation Resource Models."

Transmission Topology: The transmission topology is that contained within the 2028 ADS PCM with interface paths monitored as further described in Appendix D under "Transmission Models."

SC3: Load

Unserved load for SC3 totaled 98 GWh across all regions but occurred primarily in the Basin and Rocky Mountain regions and, to a lesser extent, in the Southwest region shown in Figure 54. Unserved load in SC3 was much less than the 306 GWh of unserved load that occurred in the 2038 Reference Case and slightly less than that of SC1.

Figure 54: Unserved Load for 2038 Scenario 3 WTC WEV

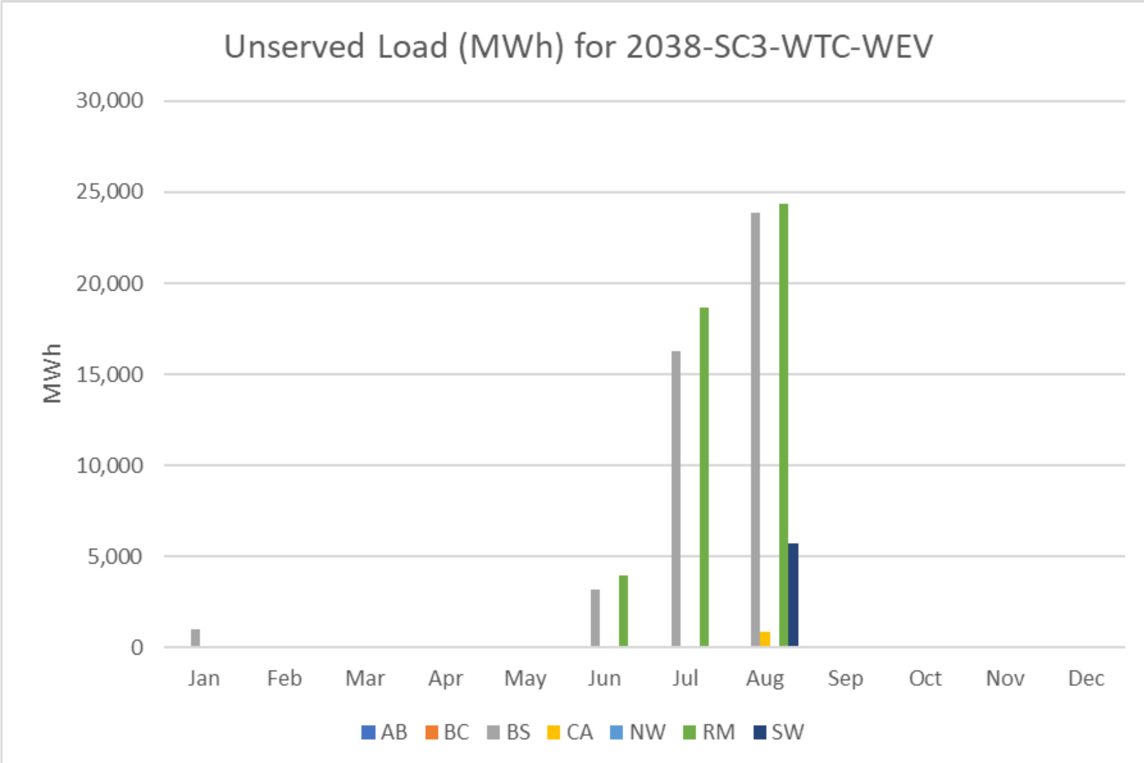


Figure 55: Unserved Load for 2038 Reference Case WTC NEV

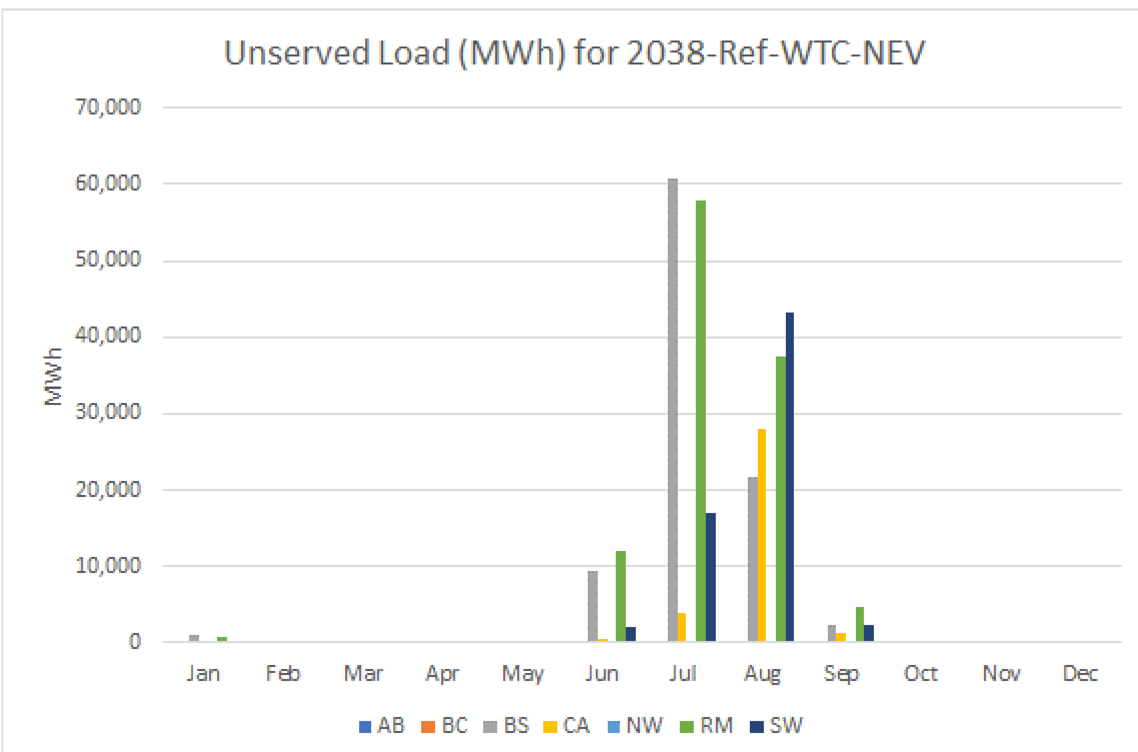


Figure 56: Load/Gen Comparison - 2038 Scenario 3 to 2038 Reference Case

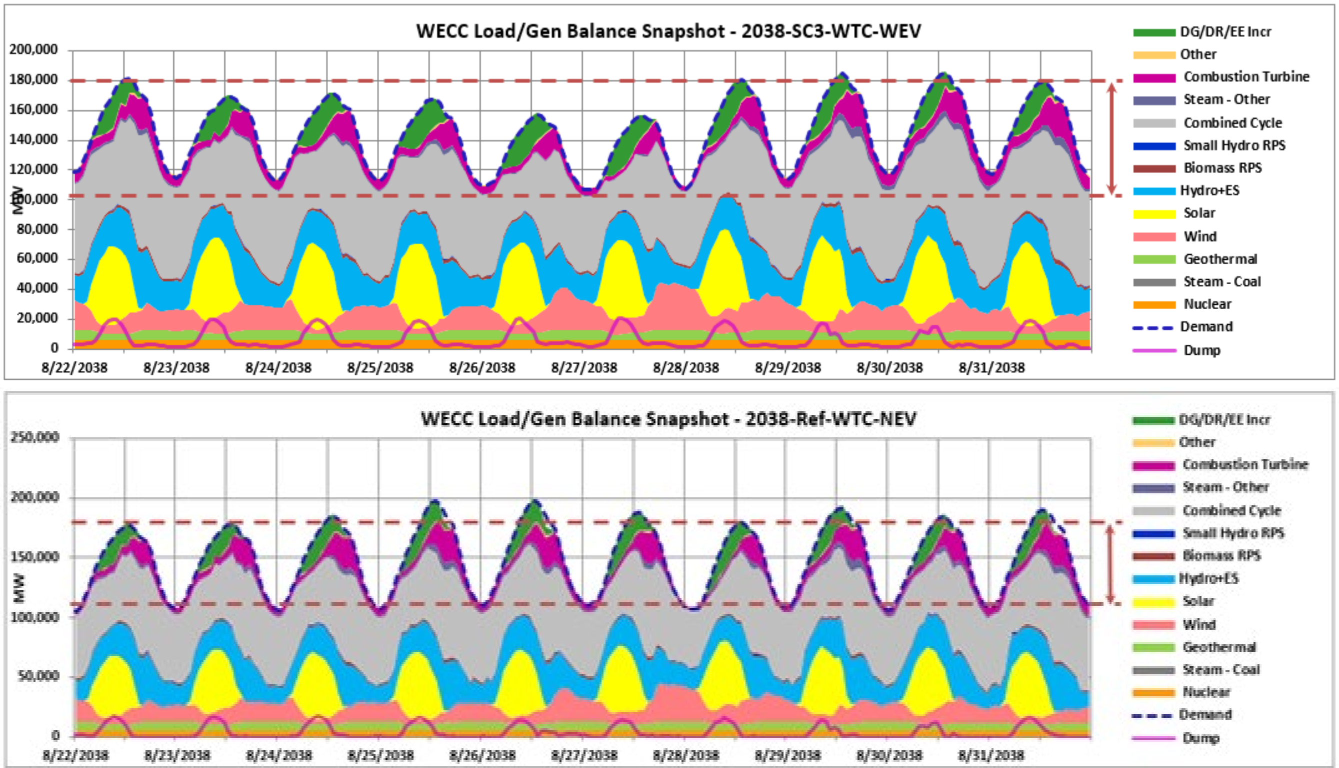


Figure 57: Electrical Storage Comparison - 2038 Scenario 3 to 2038 Reference Case

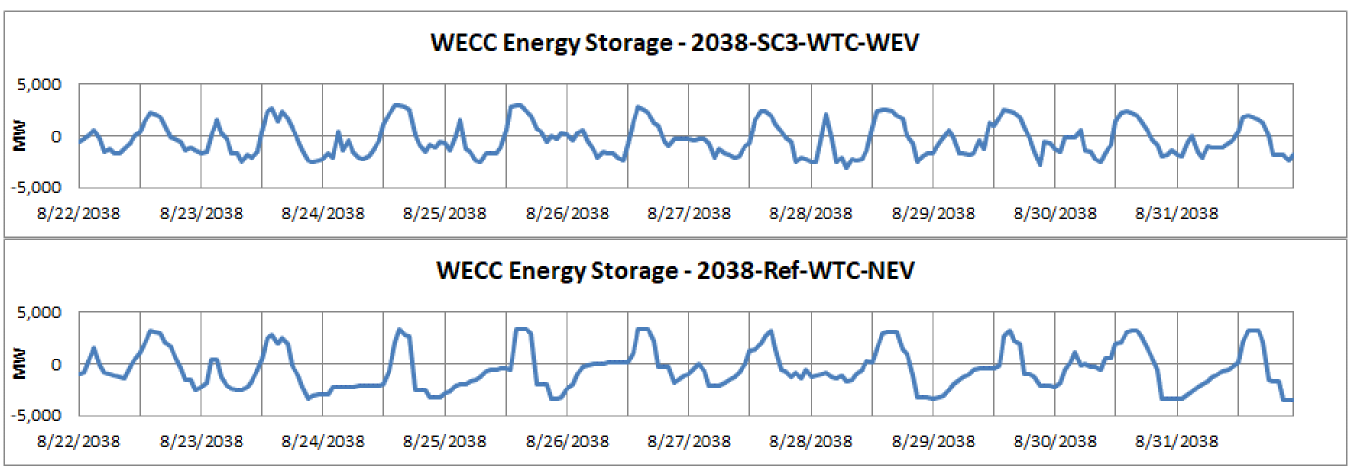


Figure 58: Comparison of Net Load – 2038 Scenario 3 to 2038 Reference Case

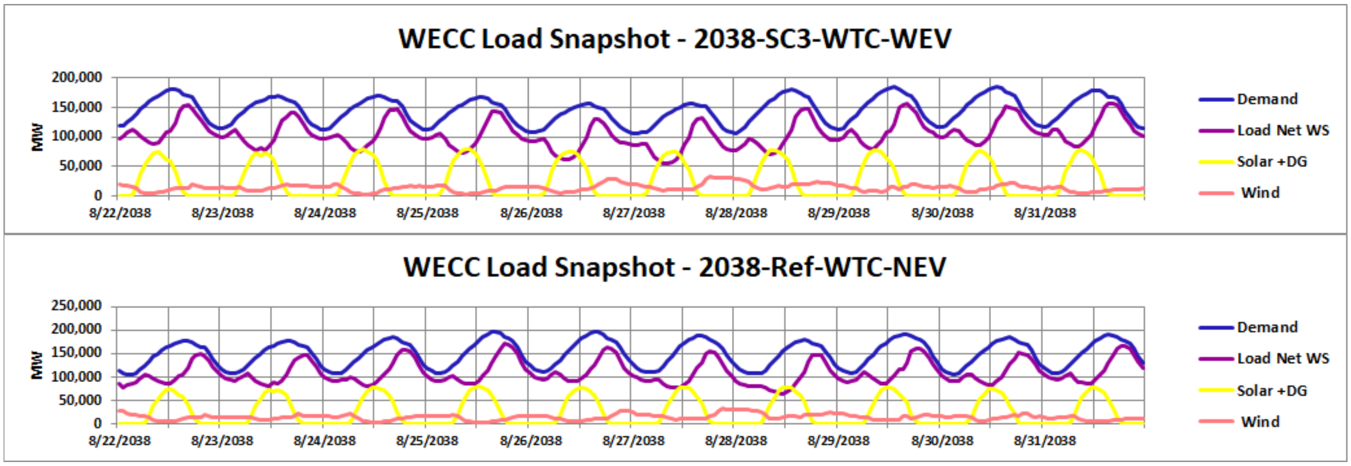


Figure 59: LMP Snapshot Comparison - 2038 Scenario 3 to 2038 Reference Case

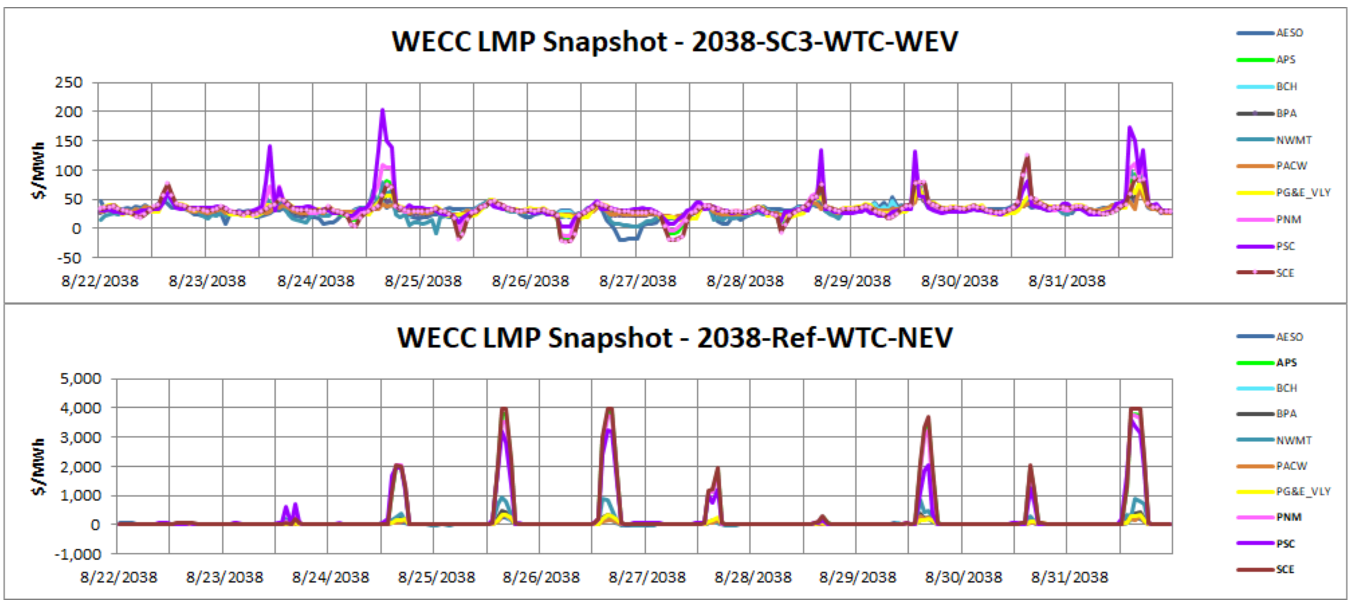
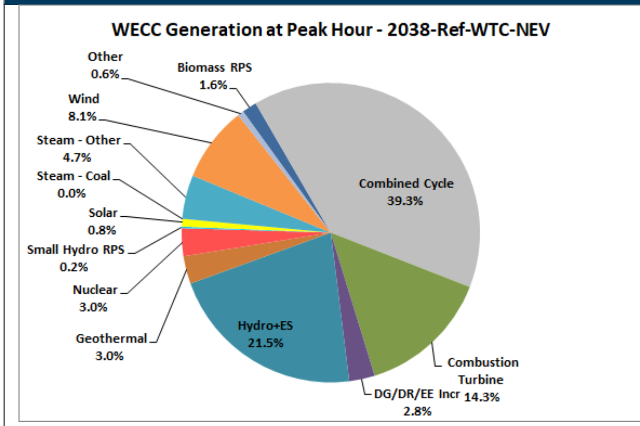
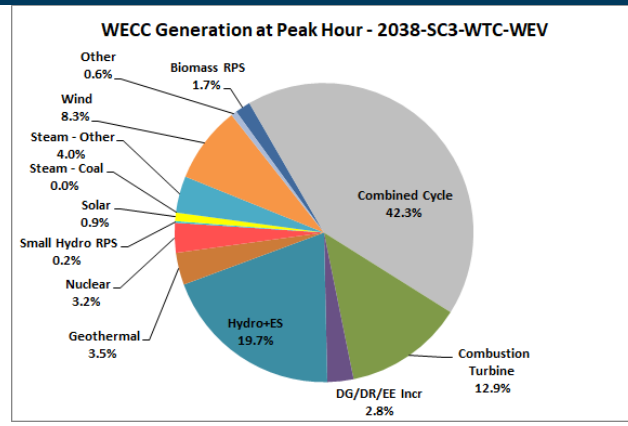
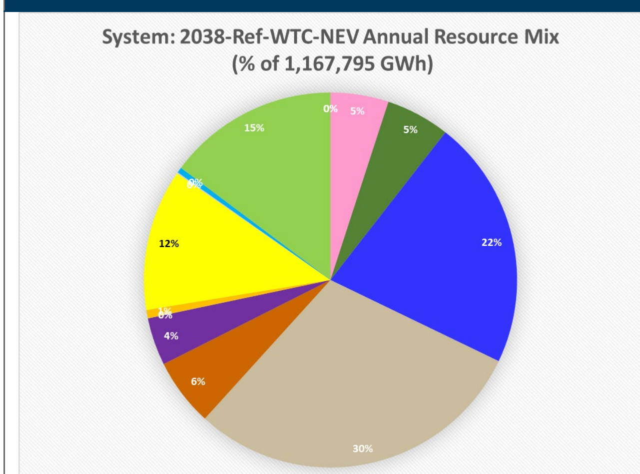
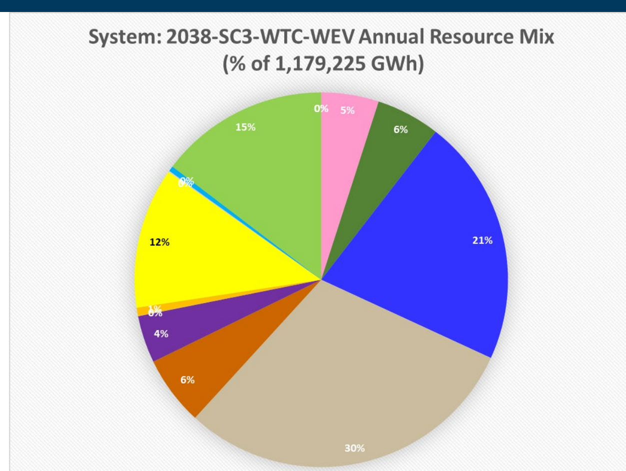


Figure 60: Generation at Peak Hour Comparison - 2038 Scenario 3 to 2038 Reference Case

2038 Reference Case	2038 SC1-WTC-WEV
	

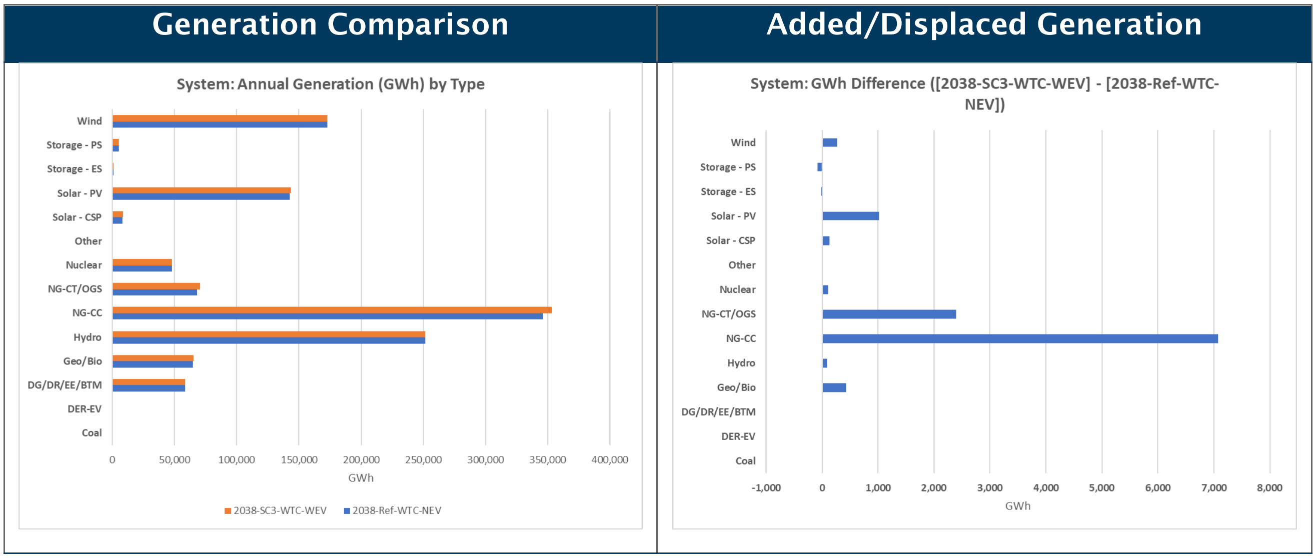
SC3: Generation

Figure 61: Comparison of Annual Resource Energy Production (GWh) – Scenario 3 to 2038 Reference Case

Reference Case	Scenario 3
	

Coal	DER-EV	DG/DR/EE/BTM	Geo/Bio	Hydro
Nuclear	Other	Solar - CSP	Solar - PV	Storage - ES
NG-CC	NG-CT/OGS	Storage - PS	Wind	

Figure 62: Scenario 3 – Resource Additions/Displacements by Type (GWh)



SC3: Inter-Regional

Figure 63: Most Heavily Used Paths – Scenario 3

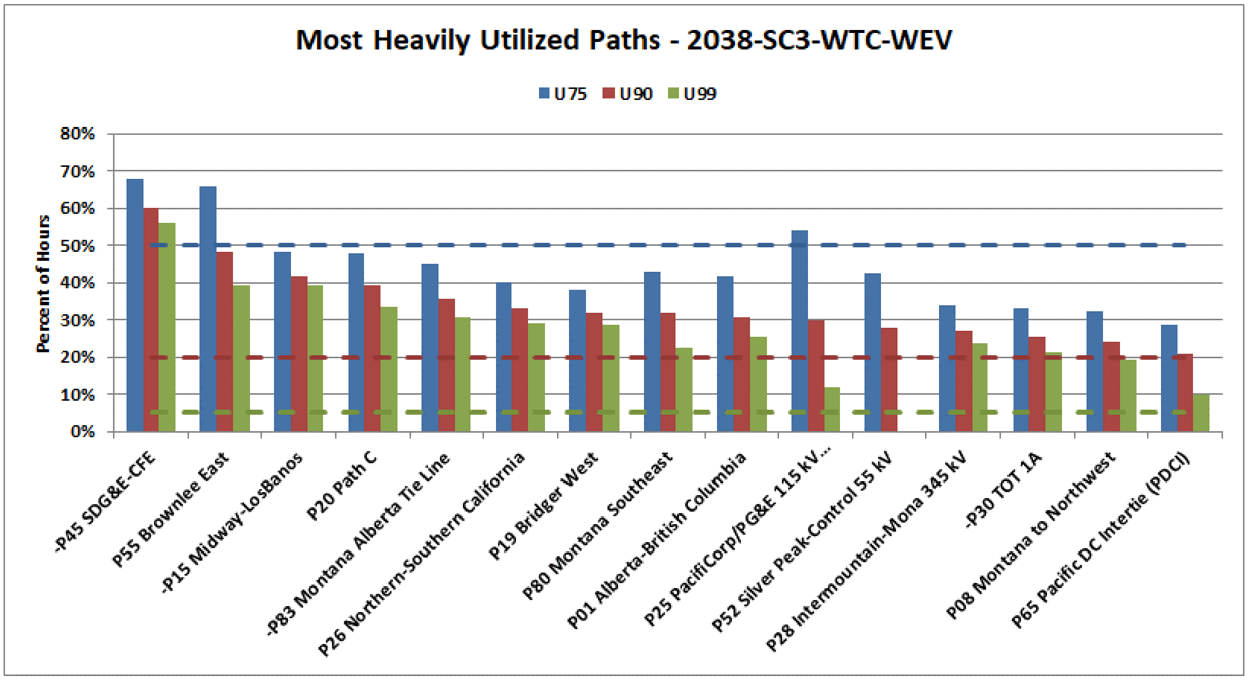


Figure 64: Most Heavily Used Paths – 2038 Reference Case

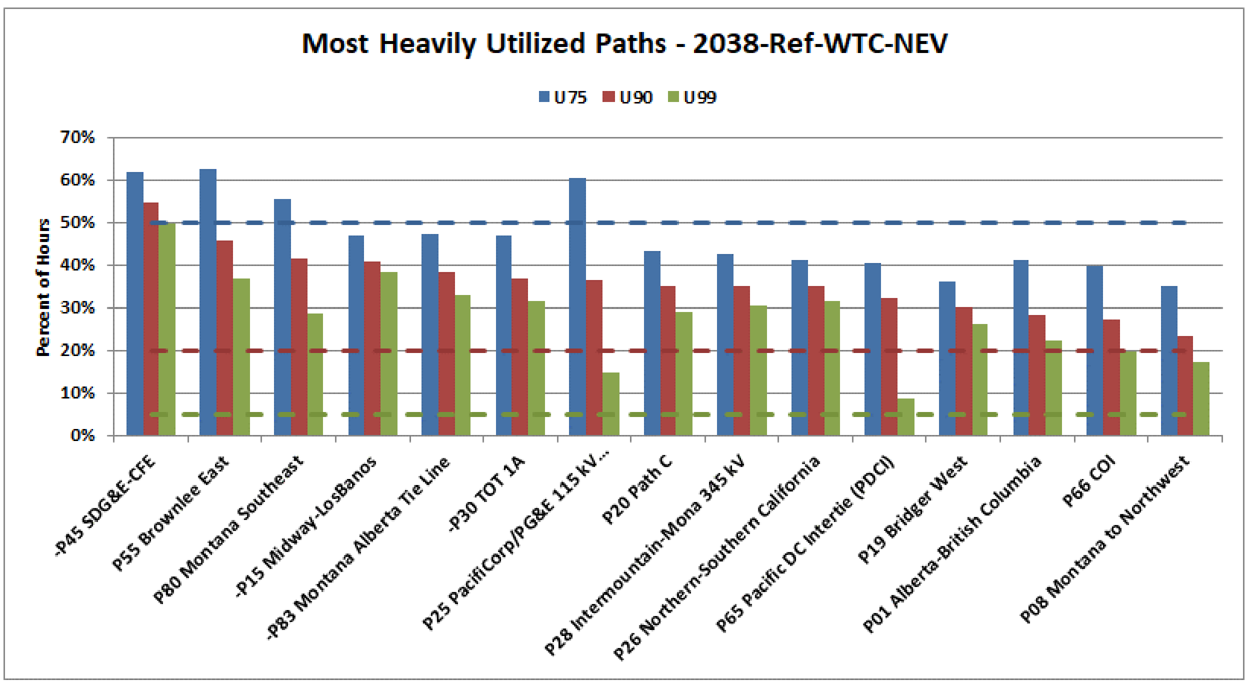
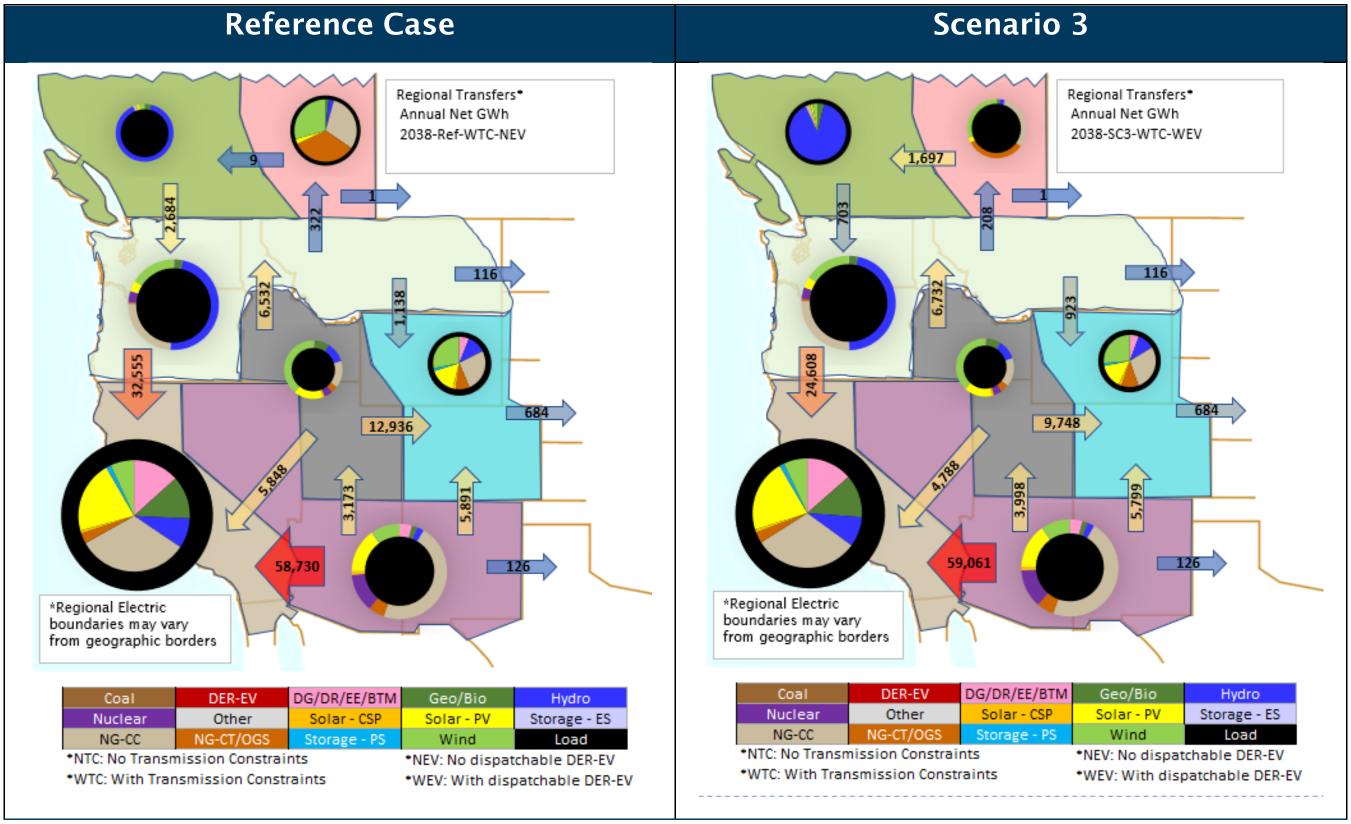


Table 10: Correlation of Heavily Used Paths to Regions – Scenario 3

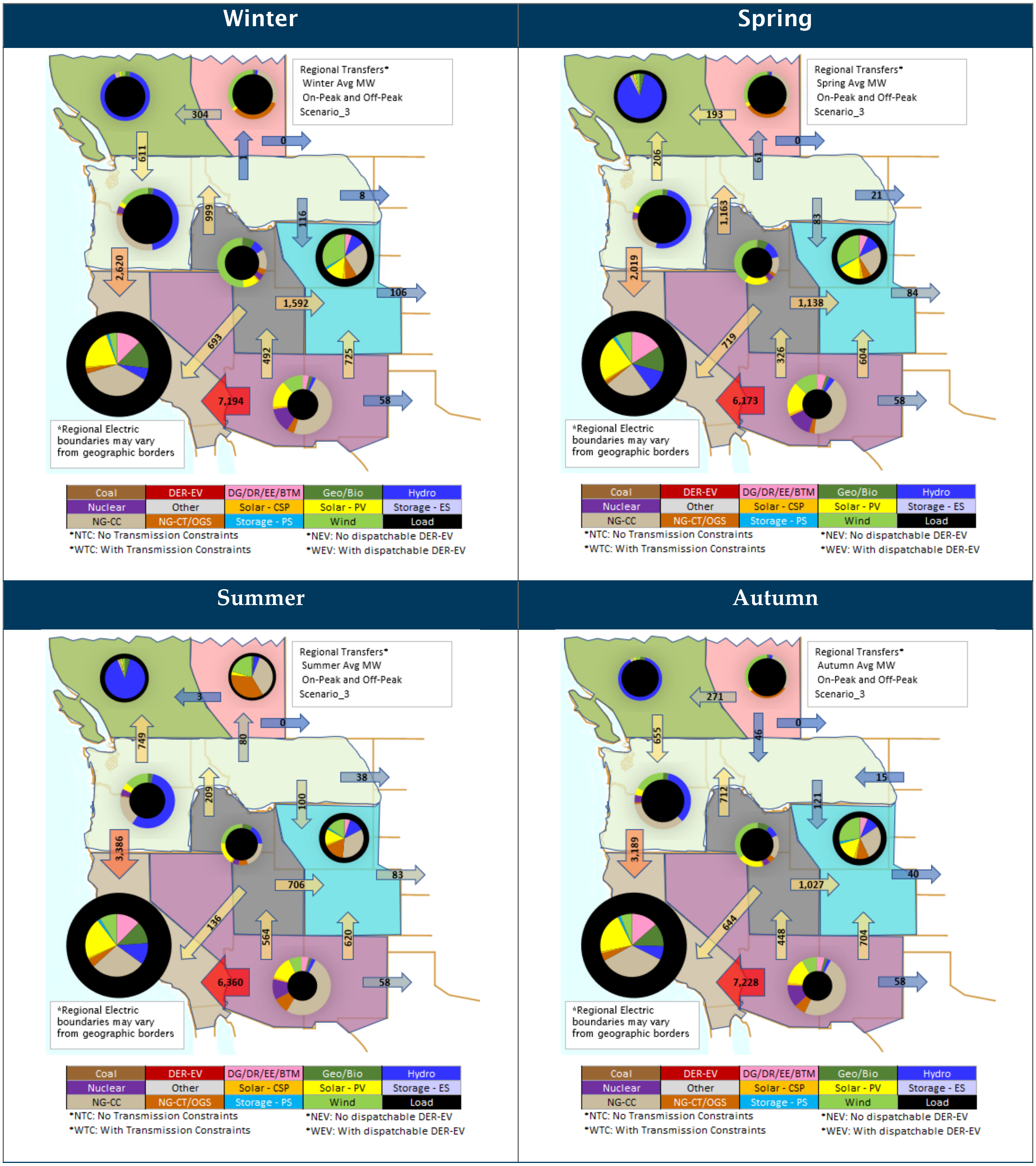
Path	Region(s)
P01 Alberta-British Columbia	Alberta, British Columbia
P08 Montana to Northwest	Northwest
P15 Midway-LosBanos	California
P19 Bridger West	Basin, Rocky Mountain
P20 Path C	Basin, Northwest
P25 PacifiCorp/PG&E 115 kV Interconnection	California, Northwest
P26 Northern-Southern California	California
P28 Intermountain-Mona 345 kV	Basin
P30 TOT 1A	Basin, Rocky Mountain
P45 SDG&E-CFE	California, Mexico
P52 Silver Peak-Control 55 kV	Basin, California
P55 Brownlee East	Basin, Northwest
P65 Pacific DC Intertie (PDCI)	California, Northwest
P66 COI	California, Northwest
P80 Montana Southeast	Northwest
P83 Montana Alberta Tie Line	Alberta, Northwest
Heavily Used in the Reference Case Only	
Heavily Used in Scenario 3 Only	
Heavily Used in both Scenario 3 and the 2038 Reference Case	

Figure 65: Path Flow Comparison of Scenario 3 to 2038 Reference Case



SC3: Seasonal Variations

Figure 66: Seasonal Path Flow Variations for Scenario 3



SC3: Key Scenario Questions and Takeaways

1. As more utility-scale wind and solar resources are brought into the Western Interconnection, what other non-intermittent resources may be needed to ensure reliability in the Western Interconnection?

   The SCRP for SC3 was derived from the 2028 ADS PCM plus additional resources to arrive at a resource mix equivalent to that of the Mid-Case Resource Portfolio; it was then further augmented to include dispatchable DER-EV equivalent to that of the NREL Demand-Side Scenario characterized by Reference Consumer Adoption and Slow Technology Advancement (see the Assessment Approach section and Appendix D for more details). This candidate portfolio appeared to be adequate to meet the load requirements of SC1 and SC3 but fell short in providing resource flexibility at evening peak for SC2 and SC4. In the SCRPs for all Scenarios, energy production from solar represented roughly 12% of the total energy production from the SCRPs. Most of that energy production occurred when load demand was low, while solar provided less than 1% of the dispatch at evening peak when unserved load occurred. Gas fired generation and DG/DR/EE/BTM provided 58% of the dispatch at evening peak for SC1 and SC3, when little unserved load occurred, and 56% of the dispatch at evening peak for SC2 and SC4, when a large amount of unserved load occurred. This represents 2% difference in dispatch from gas fired generation and DG/DR/EE/BTM for SC1 and SC3 relative to SC2 and SC4. This observation suggests a 58% threshold of resource flexibility at evening peak demand is required for the Scenario simulations to avoid the occurrence of unserved load. Unserved load occurred when evening peak demand exceeded 180 GW. Peak demands for SC1 and SC3 were right at this limit. Peak demand for SC2, where the occurrence of unserved load was at its greatest, was 225 GW. Roughly 131 GW of resource flexibility would be required to maintain the 58% threshold, a difference of roughly 4.5 GW, for all the Scenarios.

   a. What policies should govern the addition of those utility-scale, reliability-related resources so that they are optimized across the Western Interconnection (thus taking advantage of the bulk transmission system to allow the sharing of resources and thus lower overall region-wide costs)?

      Mechanisms are needed to ensure that adequate resource flexibility exists as electrification and the penetration of variable (intermittent) resources increase. Resource flexibility strategies should be developed in concert with demand-side management.

   b. What economic basis would be best suited to determine the appropriate addition of those utility scale reliability resources on a regional basis?

      While the investment and LCOE costs of new resources are examined in this section under "Economics Analysis."

      - Who provides resource flexibility?

      - Who will pay for resource flexibility?

      - How will fairness be assured?

      - How will reliability be assured?

These questions have largely already been answered in the industry, but generally only on a sub-regional basis. In order scale the answers to these questions regionally, protocols will need to leverage regional economies of scale as the energy future of the Western Interconnection continues to transform. Again, demand-side management should be integral to any strategy formulated around reliability.

2. Is there an optimal sub-regional structure (sub-dividing the Western Interconnection) for the addition of utility-scale resources (new capacity) that will support and ensure reliability as more intermittent resources are added by load-serving entities?
   WECC does not take a position on nor recommend where resources should be built. WECC will, however, do studies where resources are geographically placed according to specifications from a study request or where there is energy production potential (e.g., wind or solar potential). WECC uses data provided from NREL that estimates the geographic energy production potential of renewable resources across the Western Interconnection. WECC also relies upon underlying assumptions vetted through the stakeholder review to craft studies (e.g., located DER at load centers). Transmission constraints may also limit the amount of energy production that can be obtained from a resource at a given geographic location. In a PCM, LMP price spreads will show where transmission constraints occur. From this perspective, locating resources where high LMPs occur is more desirable than where low LMPs occur. Locating flexible resources in California and the Rocky Mountain regions seem to offer the most promise since these regions have a deficit of generation to load in the simulations.

Scenario 4 (SC4)

SC4 is characterized in the Scenario Matrix as policy-driven with higher levels of customer service option choices. The following list are assumptions that came from the narratives for SC4 in the Scenario Matrix. [16] Following each assumption are descriptions of the modeling approaches to capture the assumption to the extent that the models were able to capture the assumptions:

- Regulations are put in place to ensure that standards are met for reliability and system integrity purposes.
  Captured primarily by assumptions about technology advancement in terms of cost and performance. In other words, how will regulations affect technology innovation and customer adoption? In this scenario, the NREL Moderate assumptions for technology advancement is chosen. The Moderate Advancement case is intended to reflect a moderate increase in technology trends beyond current levels in innovation, research and development, deployment, cost reductions, and performance improvements. [1]
- Customers are directed towards new service options based on regulatory approval to ensure reliability.
  The NREL Medium trajectory for end-use Technology Adoption was used. The Medium scenario is intended to reflect an electrification future that is plausible but not transformational. It includes accelerated adoption of electric technologies serving end uses in all sectors; however, electric technologies

are not ubiquitous in this scenario where technical, economic, and consumer preference obstacles remain for certain end users. Even for services where increased electrification is assumed to occur, adoption of end-use technologies often remains in the diffusion stage or saturates at somewhat modest levels by 2050. For other services, electrification is assumed to still be at the early stages with uptake occurring only in limited markets and by early adopters. [1]

- The bulk transmission system is protected and maintained to assure reliability for the interconnection.
  SC4 is modeled with the same reliability requirements as that of the 2028 ADS PCM including transmission path limits, resource flexibility thresholds, and other operational security constraints.

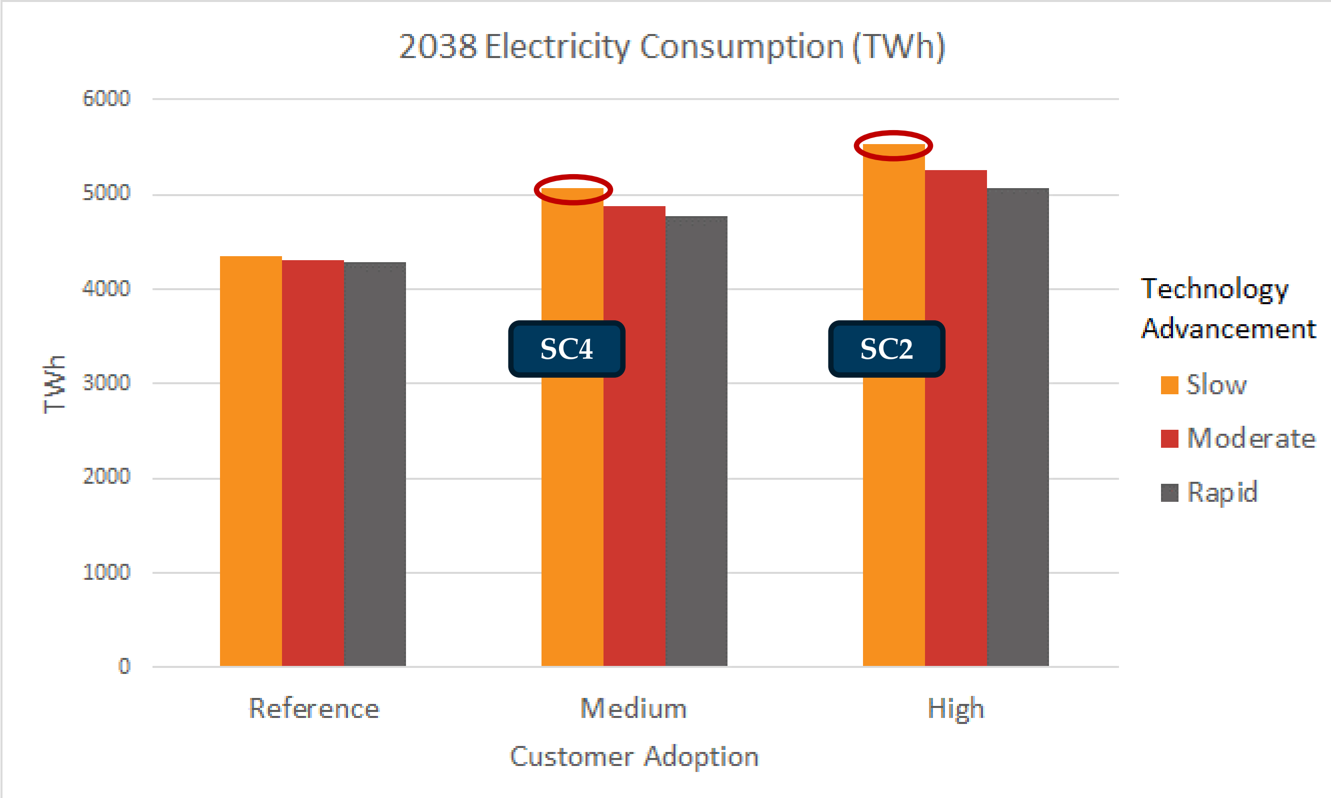
The load profile selected for SC4 is the Medium Customer Adoption / Moderate Technology Advancement. The load profile selected for SC2 is the High Customer Adoption / Moderate Technology Advancement. The load profiles selected for SC2 and SC4 both have the Moderate trajectory for technology advancement of new consumer choice options as shown in Table 11.

- **Table 11: NREL Demand-Side Scenarios Matrix [1]**

	Slow Technology Advancement	Moderate Technology Advancement	Rapid Technology Advancement
Reference Customer Adoption	Reference Adoption, Slow Technology Advancement SC3	Reference Adoption, Moderate Technology Advancement SC1	Reference Adoption, Rapid Technology Advancement
Medium Customer Adoption	Medium Adoption, Slow Technology Advancement	**Medium Adoption, Moderate Technology Advancement** SC4	Medium Adoption, Rapid Technology Advancement
High Customer Adoption	High Adoption, Slow Technology Advancement	High Adoption, Moderate Technology Advancement SC2	High Adoption, Rapid Technology Advancement

The Moderate trajectory for technology advancement load levels change slightly as customer adoption changes as shown in Figure 67.

Figure 67: NREL Demand-Side Scenarios -- 2038 Adoption versus Tech Advancement [1]



- Since the load levels for SC4 and SC2 differ only slightly, the results for SC2 and SC4 are similar. For that reason, the analysis for SC4 will be similar as that for SC2. As such, analysis will not be repeated for SC4. Only the charts and brief discussions for SC4 will be presented.

SC4: Modeling Components

The modeling components below were selected based on the narrative for SC4 to the extent that changes from that of the Reference Case were needed to capture the intentions behind this scenario narrative. While it is not possible to match all parts of the narrative with an equivalent quantitative measure, the learning process involved in scenario modeling advances with additional iterations, as should the modeling capabilities.

Load Models: Derived from the NREL Demand-Side Scenario [13] with Medium Customer Adoption of new service options and with Moderate Technology Advancement assumptions as further described in Appendix D under "Load Models."

Generation Resource Portfolio: Scenarios Candidate Resource Portfolio (SCRP) which is derived from the RCCRP with the addition of dispatchable DER-EV derived from the NREL Demand-Side Scenario used for SCENARIO 1 as further described in Appendix D under "Generation Resource Models."

Transmission Topology: The transmission topology is that contained within the 2028 ADS PCM with interface paths monitored as further described in Appendix D under "Transmission Models."

SC4: Load

SC4 had a total of 149 GWh of unserved load, primarily in the Basin and Rocky Mountain regions and, to a lesser extent, in the Southwest region as shown in Figure 68. Unserved load in SC4 was less that for SC2 and more than that for SC1 and SC3.

Figure 68: Unserved Load for 2038 Scenario 4 WTC WEV

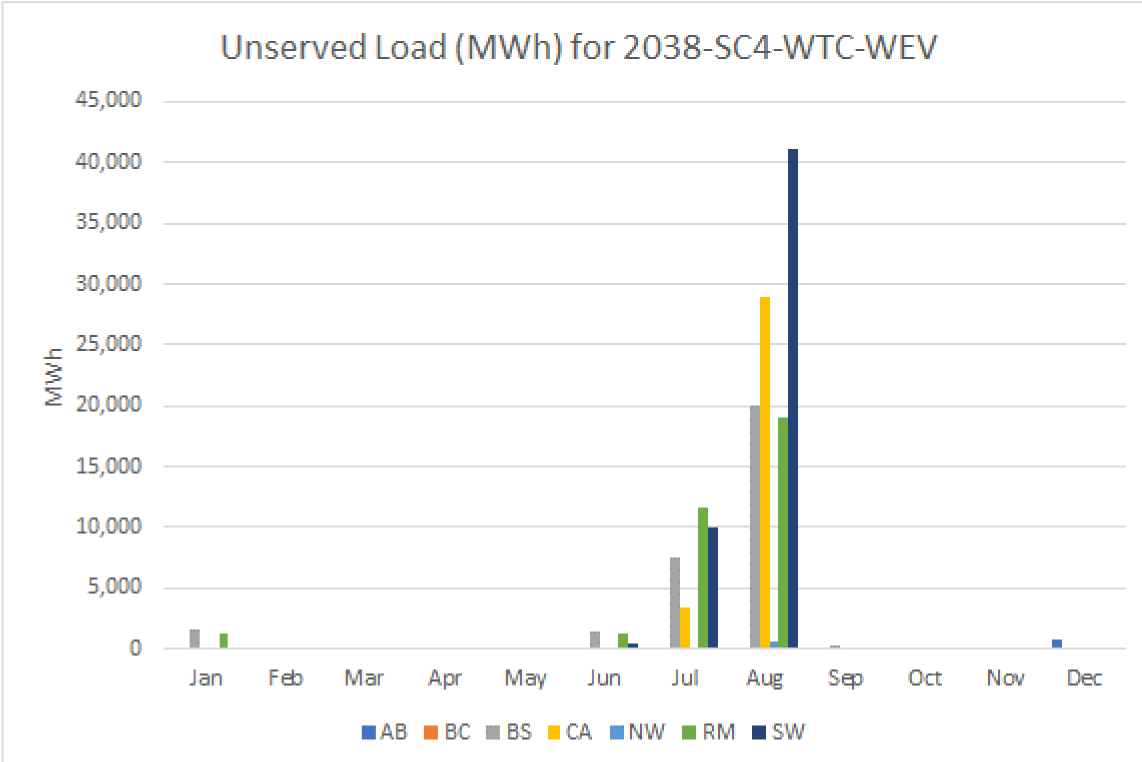


Figure 69: Unserved Load for 2038 Reference Case WTC NEV

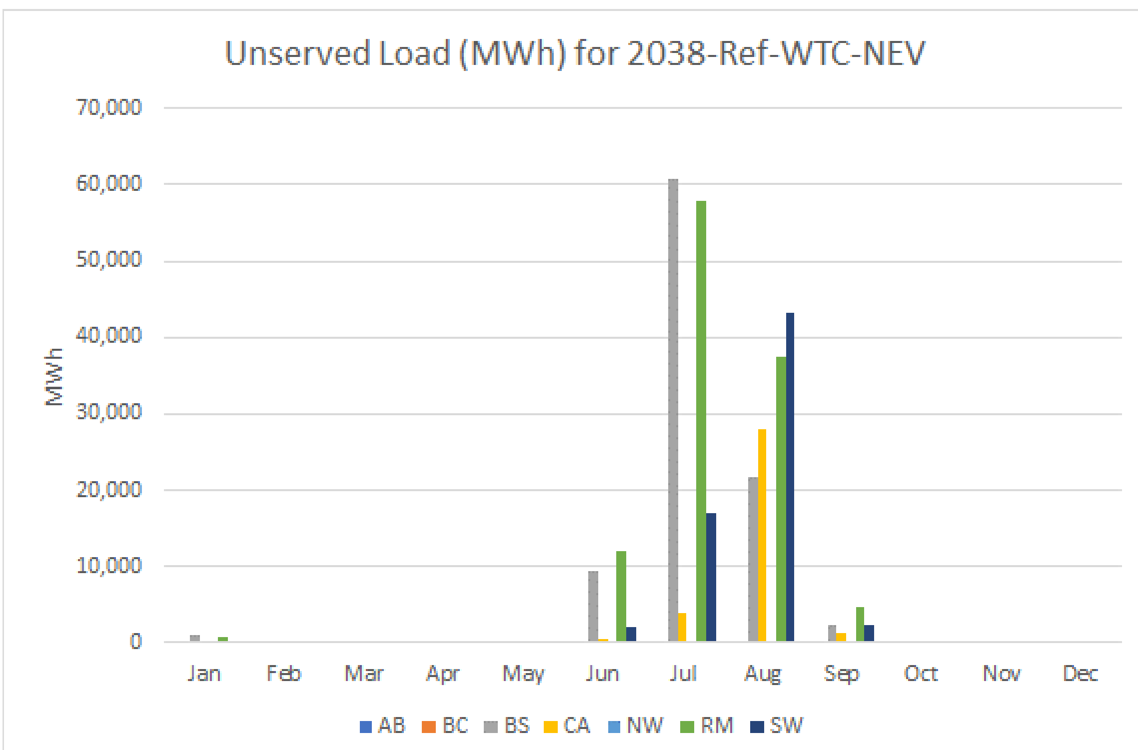


Figure 70: Load/Gen Comparison - 2038 Scenario 4 to 2038 Reference Case

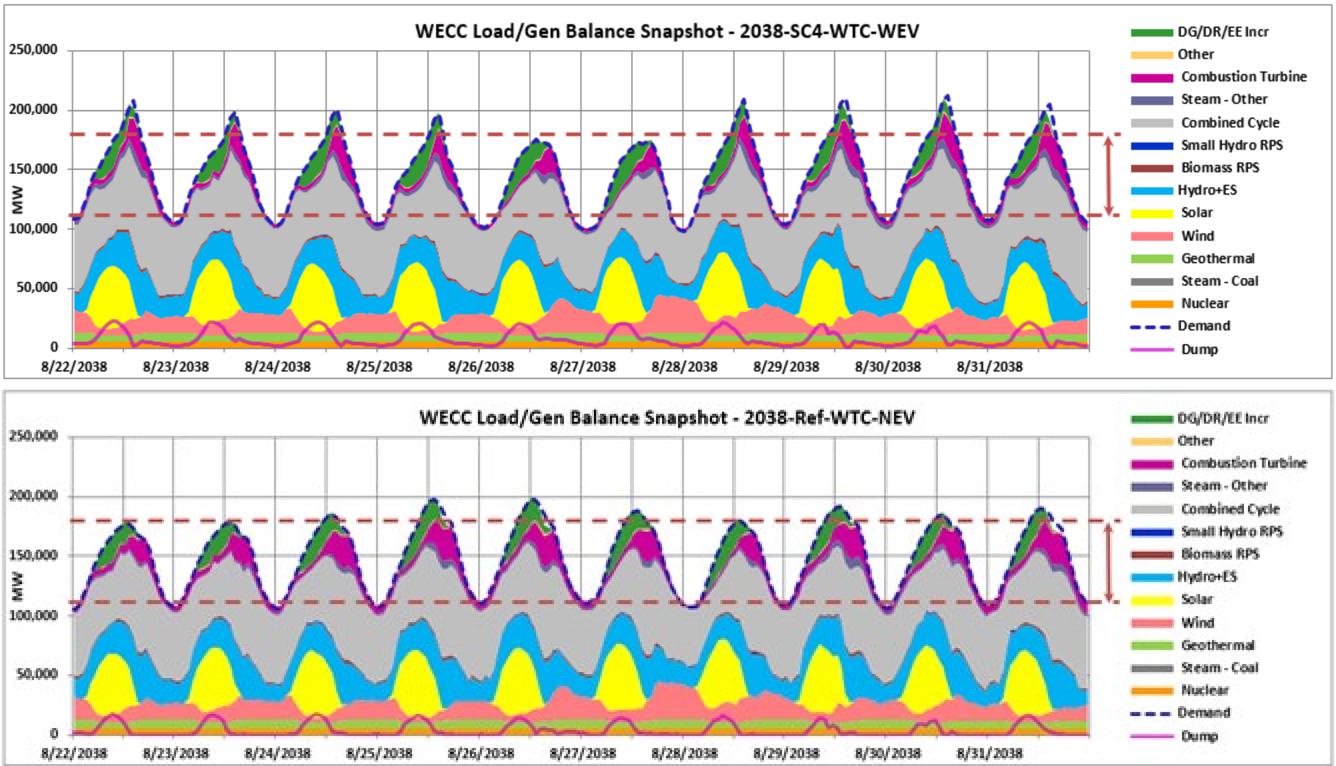


Figure 71: Electrical Storage Comparison - 2038 Scenario 4 to 2038 Reference Case

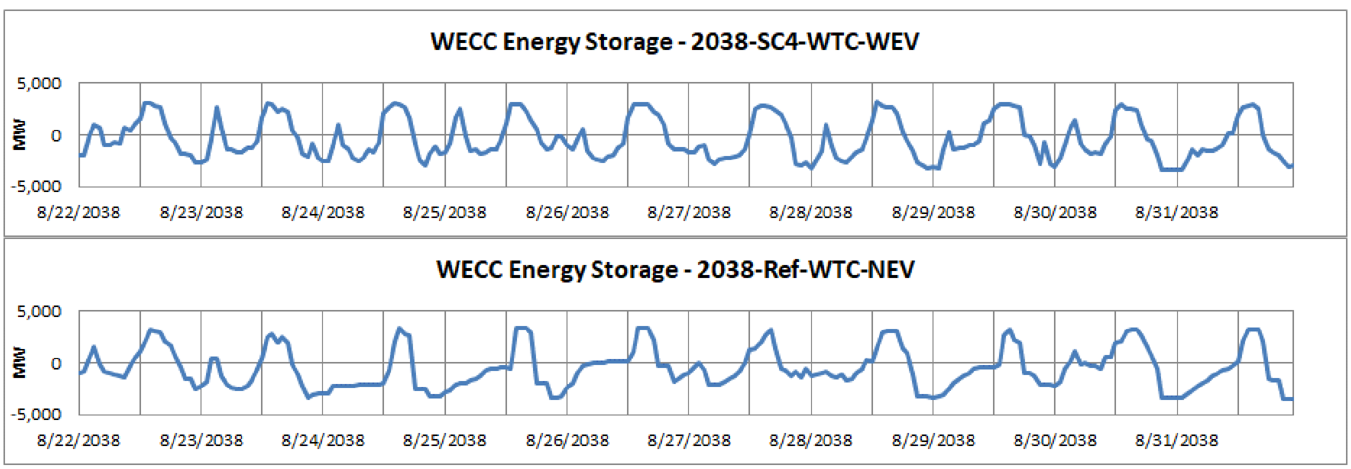


Figure 72: Comparison of Net Load – 2038 Scenario 4 to 2038 Reference Case

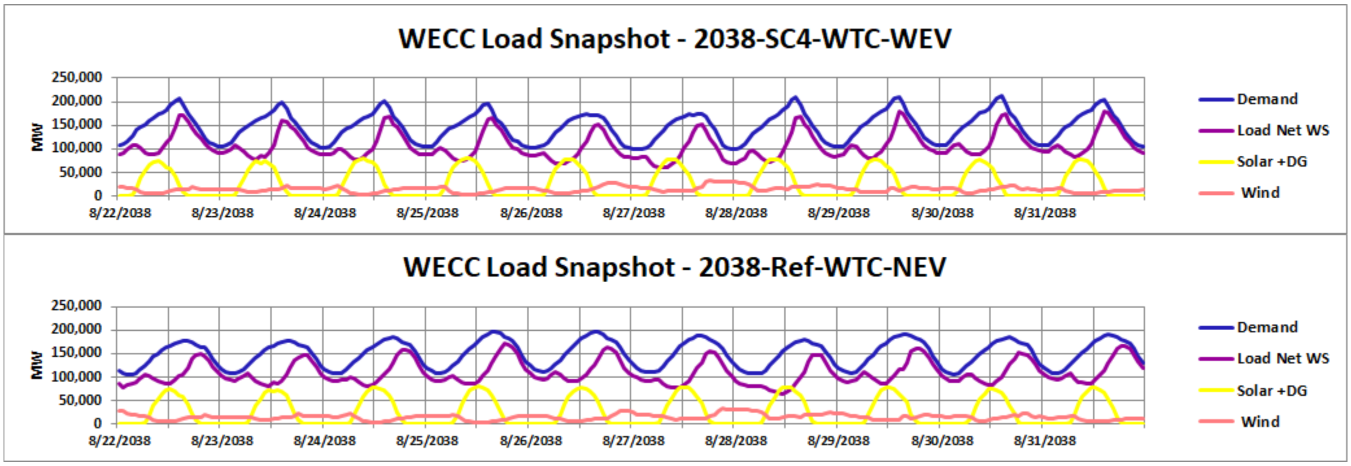


Figure 73: LMP Snapshot Comparison - 2038 Scenario 4 to 2038 Reference Case

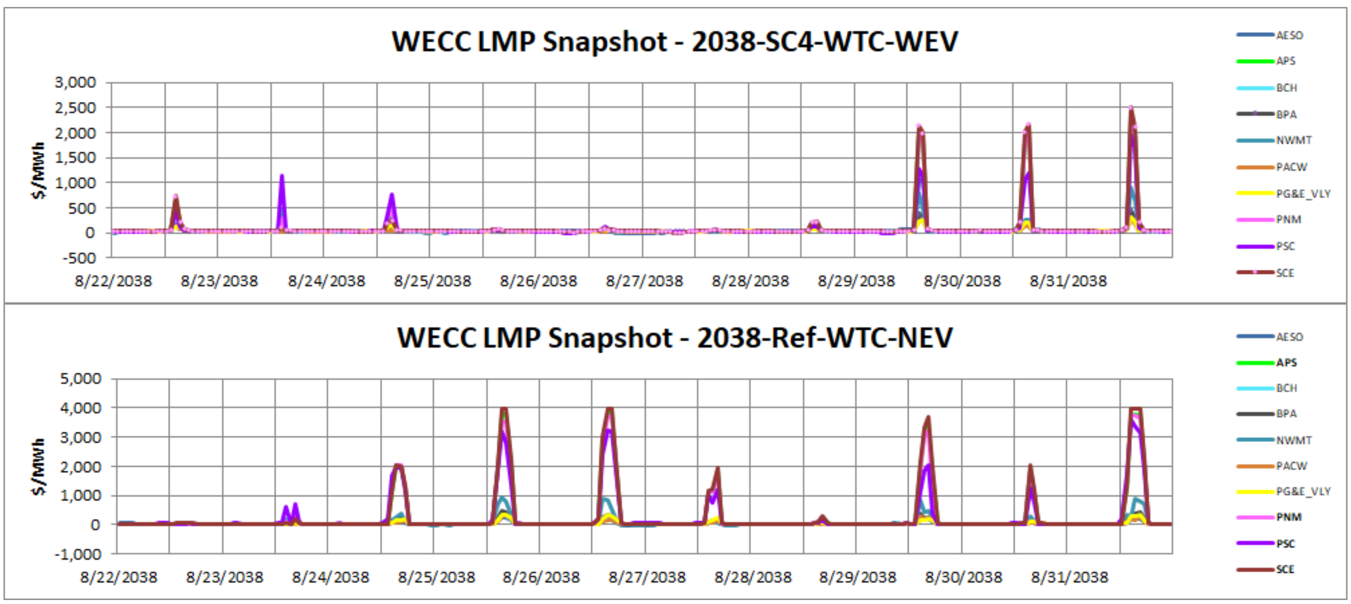
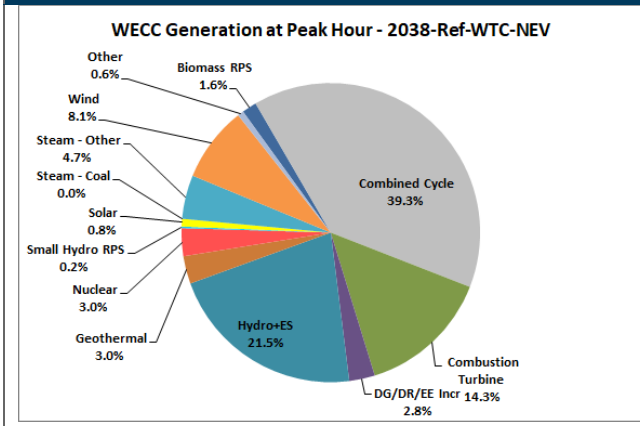
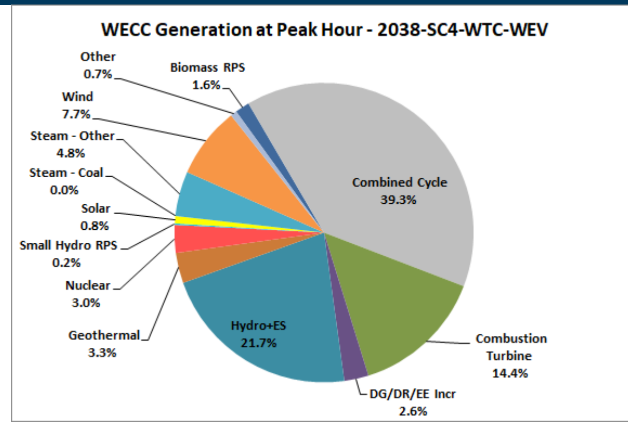


Figure 74: Generation at Peak Hour Comparison - 2038 Scenario 4 to 2038 Reference Case

2038 Reference Case	2038 SC1-WTC-WEV

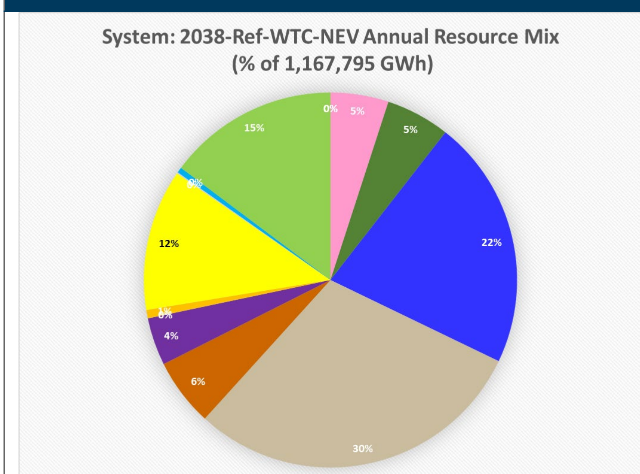


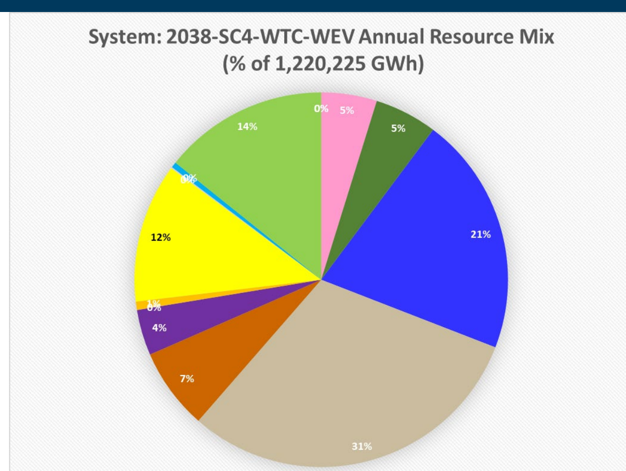


SC4: Generation

Figure 75: Comparison of Annual Resource Energy Production (GWh) – Scenario 4 to 2038 Reference Case

Reference Case	Scenario 4





Coal	DER-EV	DG/DR/EE/BTM	Geo/Bio	Hydro
Nuclear	Other	Solar - CSP	Solar - PV	Storage - ES
NG-CC	NG-CT/OGS	Storage - PS	Wind	

Figure 76: Scenario 4 – Resource Additions/Displacements by Type (GWh)

SC4: Inter-Regional

Figure 77: Most Heavily Used Paths – Scenario 4

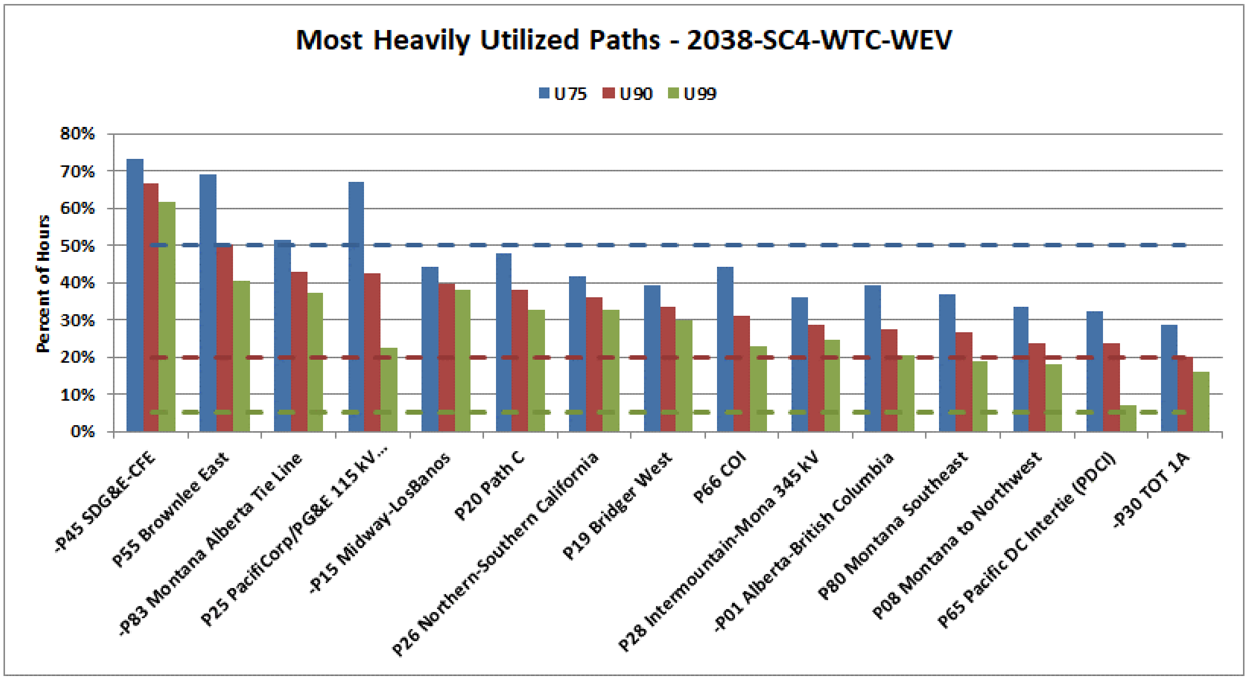


Figure 78: Most Heavily Used Paths – 2038 Reference Case

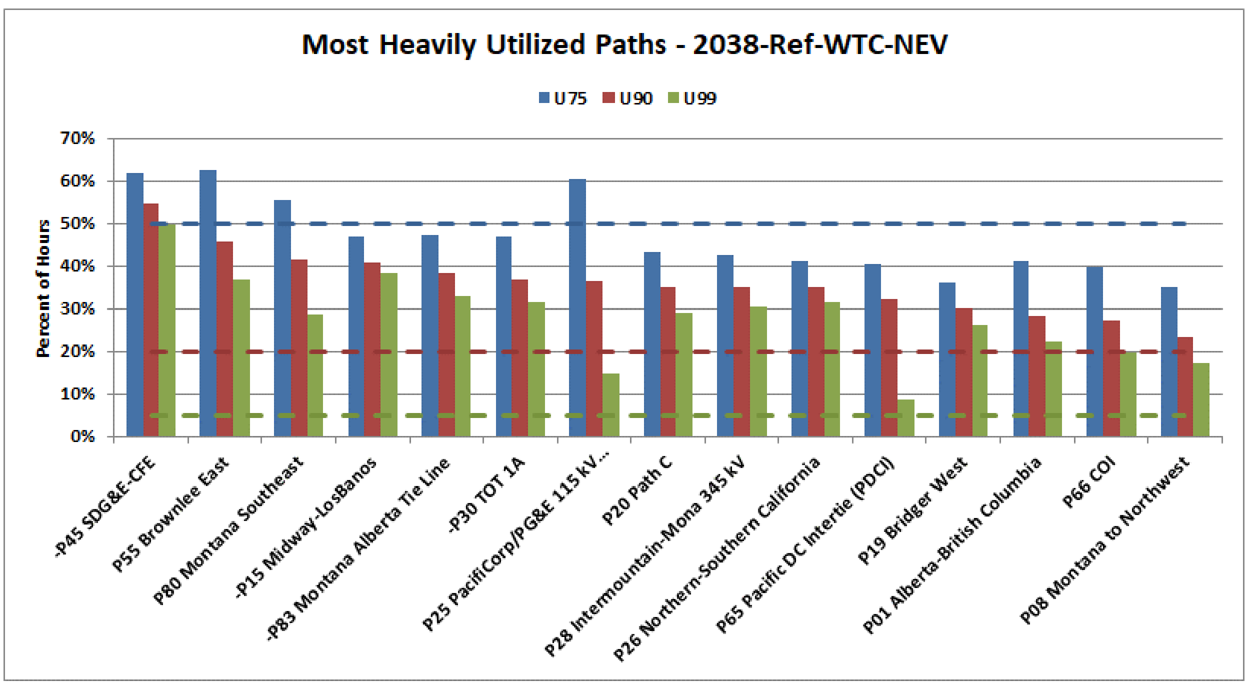
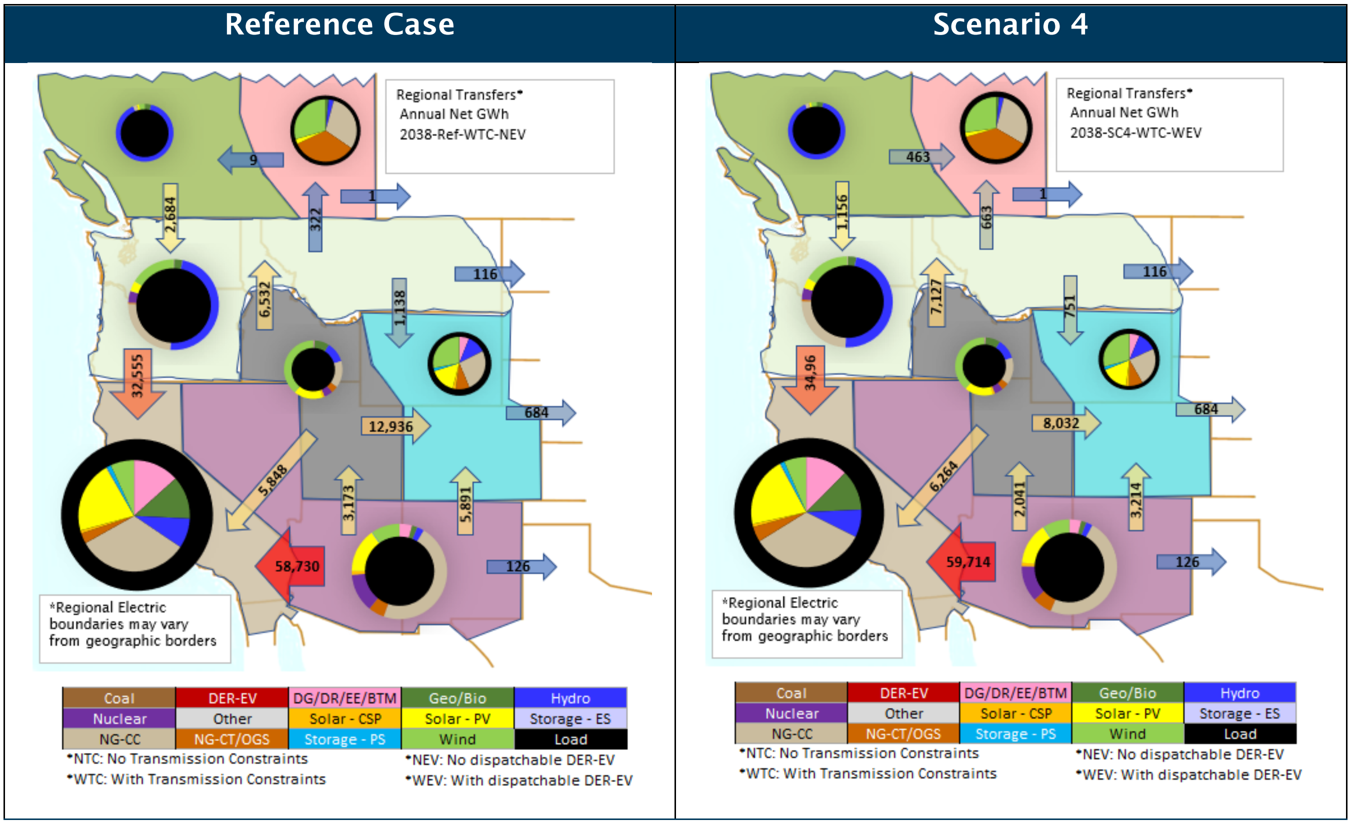


Table 12: Correlation of Heavily Used Paths to Regions – Scenario 4

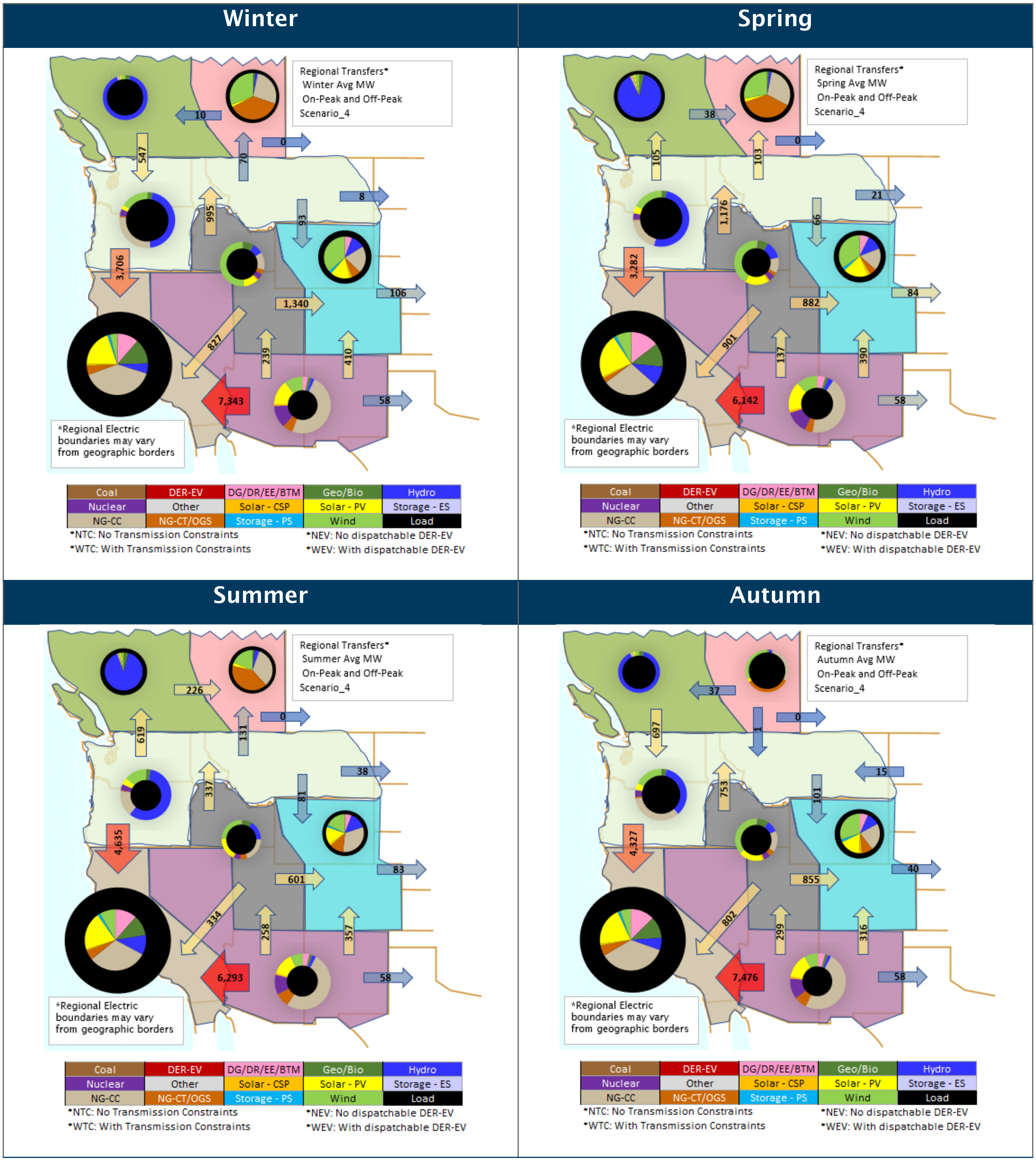
Path	Region(s)
P01 Alberta-British Columbia	Alberta, British Columbia
P08 Montana to Northwest	Northwest
P15 Midway-LosBanos	California
P19 Bridger West	Basin, Rocky Mountain
P20 Path C	Basin, Northwest
P25 PacifiCorp/PG&E 115 kV Interconnection	California, Northwest
P26 Northern-Southern California	California
P28 Intermountain-Mona 345 kV	Basin
P30 TOT 1A	Basin, Rocky Mountain
P45 SDG&E-CFE	California, Mexico
P55 Brownlee East	Basin, Northwest
P65 Pacific DC Intertie (PDCI)	California, Northwest
P66 COI	California, Northwest
P80 Montana Southeast	Northwest
P83 Montana Alberta Tie Line	Alberta, Northwest
Heavily Used in the Reference Case Only	
Heavily Used in Scenario 4 Only	
Heavily Used in both Scenario 4 and the 2038 Reference Case	

Figure 79: Path Flow Comparison of Scenario 4 to 2038 Reference Case



SC4: Seasonal Variations

Figure 80: Seasonal Path Flow Variations for Scenario 4



SC4: Key Scenario Questions and Takeaways

1. If micro-grids and customer choice aggregation reduce load-serving entities' requirements to add resources to meet reliability in their service areas, how should this be reflected in (or removed from) resource planning requirements across the Western Interconnection?
   While Micro-Grids were not explicitly modeled in the Scenario assessment beyond that captured within the NREL Mid-Case resource portfolio, Micro-Grids could, conceivably, offer great benefits if implemented in such a way that load demand as seen by a load serving entity (LSE) is smoothed by shifting load from evening peak to periods when load demand is low. If LSEs and micro-grid aggregators, along with technology innovation and rate design, were to reach a win-win strategy in this regard, it would go a long way toward offsetting the need for new resources at the BPS level to assure reliability in a highly electrified future. Such a strategy would also benefit end-use customers of both the micro-grid aggregator and the LSE. In steady-state resource planning of the BPS, the effects of micro-grids would be reflected in the load profiles. From a stability analysis standpoint, however, the aggregation of micro grids will need to be studied on a case-by-case basis just as interconnection studies are traditionally done today. Strategic planning around the interconnection of Micro-Grids to the BPS will be critical.
   a. Or should it be included, and if so, how? If there are different answers for different states, how can this be incorporated into planning analyses?
      Other questions need to be answered in this regard. For instance, how would micro-grids affect the BPS from a stability analysis standpoint? The connection interface of a micro-grid to the BPS would need to be treated as a traditional interconnection study and considered from all risk perspectives.

Cross Comparison of Scenarios

The WECC Scenarios outlined in this report present a variety of distinctions between policy development, customer demand and use of new electric services and products. As stated above, some of those differences in the narrative could not be directly modeled in this work due to data and modeling limitations. As a result, the findings of this report are not entirely comprehensive due to these limitations. However, insights gleaned from comparing the set of scenarios are set out below:

1. Load growth and shifts in energy demand by consumers as they adopt and use emerging DER and BTM energy options are identified to influence best choices for reliability assurances and the underlying economics/costs of those choices. As those choices are made, (the bulk electric system can evolve in how it is used and remain important in meeting regional reliability).
2. Growth and shifts in energy demand by consumers as they adopt and use emerging DER and BTM energy options might have the largest impacts on how that growth effects evening peak demand. As evening peak demand growth increases, so does the level of resource flexibility needed at evening peak demand periods.

3. In the absence of increased penetrations of electrical storage, demand response, and other resource flexibility options, the dependence on natural gas fired generation will likely increase to ensure reliability.
4. Mechanisms that promote demand-side management have promise to effectively address risks to reliability that high levels of electrification may introduce. Such mechanisms could include time-of-use rate structures, technology innovations, and possibly policy incentives.

A cross comparison summary between the Scenarios and the Reference Case is provided in Table 13.

Table 13: Cross Comparison of Scenarios

Measure	Reference Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Annual TWh Load	1,125	1,184	1,511	1,193	1,389
Annual Unserved Load GWH	306	10	2,860	98	149
Instances of Unserved Load	18	5	38	9	16
Peak Demand GW	200	180	230	182	215
Use of Storage at Peak Demand	Moderate	Low	Very High	High	Low
Instances of LMP Blowouts	18	5	38	9	16
Percent Resource Flexibility at Peak Demand	56%	58%	56%	58%	56%
% Gas in Annual Energy Production Mix	36%	35%	44%	36%	38%
% DG/DR/EE/BTM in Annual	5%	5%	4%	5%	5%

Measure	Reference Case	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Energy Production Mix					
% Solar in Annual Energy Production Mix	12%	12%	11%	12%	12%
% Wind in Annual Energy Production Mix	15%	15%	13%	15%	14%
Max U75 Path Use	62% P55 Brownlee East	75% P45 SDG&E-CFE	70% P55 Brownlee East	68% P45 SDG&E-CFE	72% P45 SDG&E-CFE

Economics Analysis

Locational Marginal Price (LMP), Levelized Cost of Energy (LCOE), and Capital Expansion Costs (CapEx) are the metrics upon which the economic analysis of the Scenarios was performed. Because both LMP and LCOE are expressed in units of $/MWh, the LCOE of a capital expansion project can be compared to the LMP of a PCM at a given location to judge the viability of a CapEx from an energy production standpoint. Comparisons of this type are only meaningful from an energy production standpoint and will not capture ancillary value.

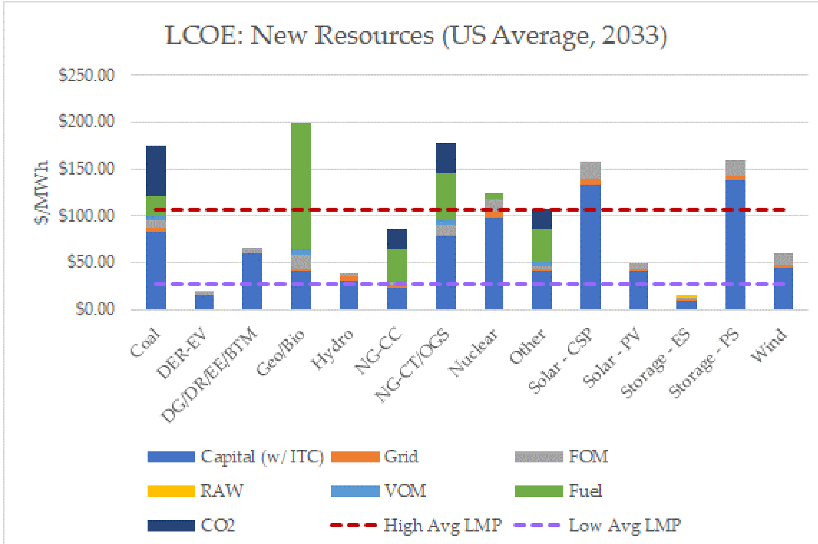
LCOE and LMP

The WECC Generation Capital Cost Tool (WECC CapEx Tool) was used to provide a qualitative estimate of the capital investments that may be needed to replace retired generation as well as new generation additions that may be needed for future demand growth. [8] Obviously, it is not reasonable to assume that all new or replacement generation will take place in 2038 to meet the reliability obligations of 2038. As with earlier study cycles, a benchmark year for capital expansion midway between the year-10 horizon and the year-20 horizon is assumed.

The capital expansion year used in this assessment is 2033. A US average is used within the WECC CapEx Tool as a basis upon which region and study horizon adjustments are made. Figure 81 shows the US average LCOE basis for 2033 as configured for this study by generation resource category. Included in Figure 26 are the average LMPs from the previous discussion. Namely, a dashed red line labeled “High Avg LMP” associated with Scenario 2 and a dashed purple line labeled “Low Avg LMP” associated with Scenarios 1, 3, and 4.

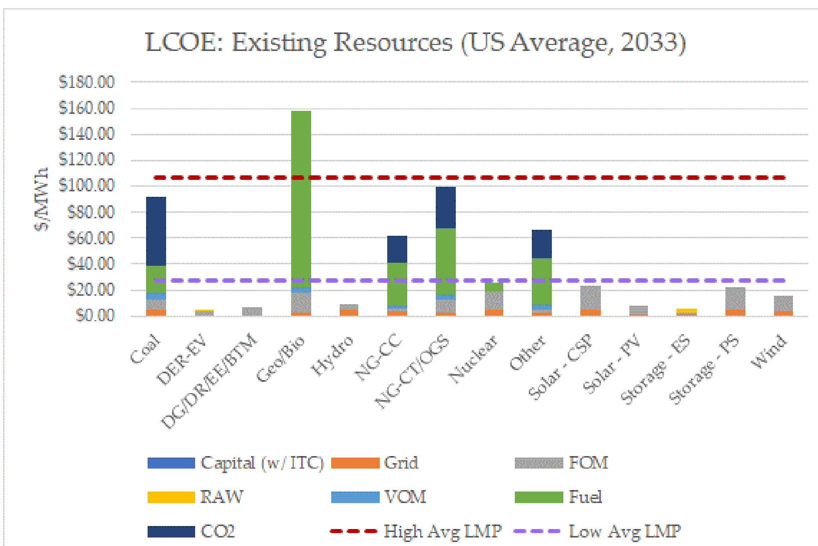
These Avg LMP lines represent an envelope across all scenarios upon investments in new resource additions may be competitive from an energy commitment and dispatch standpoint. The value of a resource cannot be judged by energy commitment alone. There is also extrinsic value that a resource may provide beyond energy production such as resource flexibility and ancillary service. Comparing LCOE with average LMP can provide a qualitative sense as to whether a resource addition is competitive from an energy commitment and dispatch standpoint and what the extrinsic value may be.

Figure 81: US Average LCOE Basis for New Generation Resources



LCOE: Levelized Cost of Energy ($/MWh) **Grid:** Transmission Expansion Costs **VOM:** Variable Operating and Maintenance Costs **RAW:** Replacement, Augmentation, Warranty Costs	**ITC:** Investment Tax Credit **FOM:** Fixed Operating and Maintenance Costs **CO2:** CO_2 Emissions Costs **RC:** Reference Case **LMP:** Locational Marginal Cost ($MWh)

Figure 82: US Average LCOE Basis for Existing Generation Resources



LCOE: Levelized Cost of Energy ($/MWh) **Grid:** Transmission Expansion Costs **VOM:** Variable Operating and Maintenance Costs **RAW:** Replacement, Augmentation, Warranty Costs	**ITC:** Investment Tax Credit **FOM:** Fixed Operating and Maintenance Costs **CO2:** CO_2 Emissions Costs **RC:** Reference Case **LMP:** Locational Marginal Cost ($MWh)

The LCOEs shown in Figure 81 represent new resource investments only. By comparison, Figure 82 illustrates the competitiveness of existing resources where capital investment is assumed to be a sunk investment and therefore zero. A comparison of this type provides a qualitative measure to assess the value of existing resource relative to new resources and what level of life extension investment may be viable.

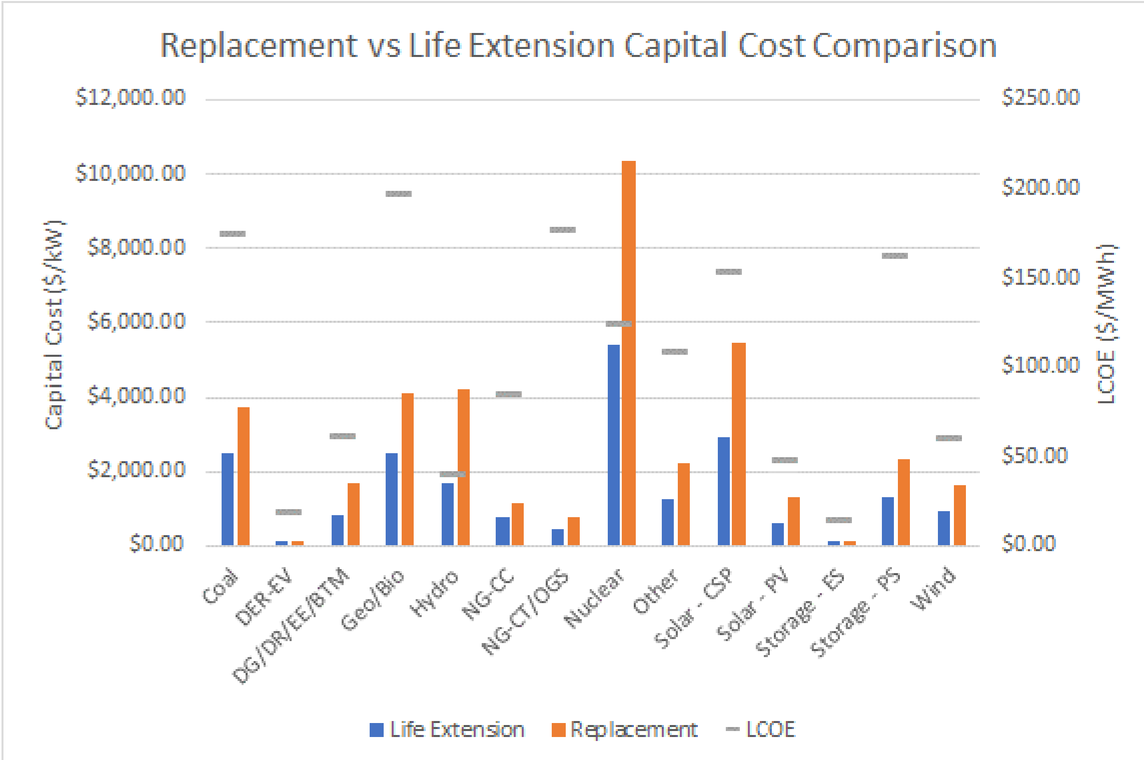
All existing resource types, except for Geo/Bio, are contained within the competitive energy envelope. Geo/Bio resources are modeled within the 2028 ADS PCM as price taking hourly resources, so they were committed and dispatched according to their hourly resource profile and therefore not subject to PCM LMP price signals. Note that existing coal fired generation was still displaced in the resource commitments as discussed earlier. This is because resources at LMPs higher than the low average are committed and dispatched primarily for resource flexibility. The commitment and dispatch of coal fired generation in the model is constrained by several factors that include minimum up-time, minimum down-time, startup costs, ramping capabilities. As such, existing coal fired generation was never committed and dispatched within the PCM simulations, even for Scenario 2.

Capital Expansion Costs

While replacement cost can be estimated with reasonable accuracy using the WECC 2019 Generation Capital Cost tool, there is no "rule-of-thumb standard" for estimating life extension costs with reasonable certainty. Every life extension decision is different as is the extent at which one is willing to invest to extend the life of existing resources. What can be assumed, however, is that the economic life of life extension investments won't be the same as that of new builds. The amount of investment required to extend the life of an existing resource has diminishing returns the further out the economic life is extended. Since economic life is key to the levelization of cost, the capital investment cost in life extension would have to be reduced to break-even with the capital investment cost of new builds with a longer economic life. A ten-year life extension is therefore assumed.

The capital investment amount for life extension at ten years was then calculated such that the resulting financing LCOE was break-even to that of new builds at full replacement economic life. This life extension cost is an estimate of what level of capital investment in life extension is reasonable relative to new build costs before diminishing returns result. A comparison of life extension cost to new build cost in terms of capital investment and break-even LCOE using this method is presented in Figure 83. Up-front capital investment cost by itself, however, is not a good measure of the economic viability of a project as there are several factors that go into the calculation of LCOE beyond just capital investment, such as performance, ongoing costs, tax, financing, emissions cost, environmental impact. Projects that have both low capital investment cost and low LCOE are the most promising from an economic standpoint. As Figure 83, illustrates, distributed generation, solar PV, electrical storage, and wind show the most promise from an economic standpoint in terms of capital investment and LCOE.

Figure 83: Comparison of Replacement vs Life Extension Capital Costs by Resource Type



7. Conclusions

Conclusions drawn from the Scenarios Assessment are organized to first revisit the focus question, which was the basis upon which the narratives of the Scenarios were crafted and then key takeaways that are focused more on the analytic results from a reliability perspective.

Focus Question (Revisited)

As stated earlier in this report, the Western Interconnection is undergoing transformation and there is a great deal of uncertainty surrounding its energy future. Considering this uncertainty, the goal of Scenario Planning is not to predict the future, but to gain a better understanding of plausible futures and underlying drivers. A guiding principle behind the WECC 2038 Scenarios Assessments is to shine a light on how underlying drivers may influence the energy future of the Western Interconnection. The scenario modeling assessments in this report are not meant to be comprehensive, but rather tools for contributing to a learning process that can be built upon.

As a reminder, this report uses the WECC Scenarios to form plausible energy futures and to craft case models to study. The resulting scenario narratives were used to guide the selection of key quantitative inputs (for example the NREL Electrification data inputs) which approximate and meet the intent of expressed in the narrative. This creates a process that is useful for approximating impacts and showing the direction of effect key variable have on one another. The process is the essential aspect of using modeling and scenarios in tandem as a learning process. In this light, as underlying data and modeling capabilities improve over time, additional scenario-based analysis can provide longer term opportunities for learning, and, allowing WECC to assess potential effects of the data for electric system reliability.

Getting the most value out of scenario planning occurs when good relevant questions are asked. The WECC Scenarios are grounded in a relevant question concerning the long-term transformation of the power industry toward a more consumer-centric and distributed base. Clearly such a transition could take several years if not decades, thus the long-term focus of this work is appropriate. As scenario analysis (including the detailed modeling herein) is used over time, the learning occurring during the analytical process can be incorporated into to refocusing key questions and capturing key insights. Also, as events unfold (such as technology advancing, or new products and services entering the marketplace), core perceptions can change.

At the time of this report, which is about two years after the original date in which the WECC Scenarios were produced, some changes in perspective have arisen. They include the following:

- The traditional power industry, especially at the utility-scale, has a history of economic analyses in which costs, performance, and benefits are looked at rigorously, often under review by regulators, to determine the least-cost delivery of services in balance with benefits such as power quality, safety, and reliability. In most consumer product markets, this rigorous and regulated approach does not exist, and only market-level responses determine which products and services are sold.
- Consumers will often pay more for some benefits that far exceed the costs of providing them, leading to high profits for producers. Consumer value propositions are often challenging to determine, and similar products with similar features can sell for radically different prices. For example, a Nissan Leaf electric vehicle sells for roughly one third the cost of the high-end Tesla EV even though both provide emission-free personal transportation. If a prototype of a mass-market, behind the meter (BTM), independent power supply that meets the full daily needs of consumers emerges in the market, it may be subject to the same market dynamics of other consumer products and thus be disconnected from any form of utility engineering economics.
- The scenario focus question anticipates the emergence of such a power source that could expand into the market without any connection to traditional utility-scale resource planning processes. Such a market disruption could lead to difficulty in utility-scale resource planning as forecasting the impacts and growth of consumer-level BTM power supplies may be difficult, and subject to sudden swings based on new consumer values. We have no idea of the long-term market response to this opportunity would be, or what new consumer values related to

behind the meter power sources and services would be. It is possible to envision a time when utility-scale resource planning is unable to respond to consumer-level market dynamics.

- Considering the points raised above, we are not only concerned about electric reliability risk to the bulk power system but also what conceivably might emerge from a dramatic increase in consumer choice options and adoption where the bulk power system is maintained but with unpredictable power flows we cannot predict, e.g., when, how much, used by whom? In such a glutted market, we are unclear on how regulators might respond, what actions suppliers may take to command market share, which assets may be stranded, or what externalities may arise.

In addition, the modeling analyses in this report have brought to light the following:

- Growth in consumer side DER and BTM energy supply resources if used in a supportive fashion with market demand can benefit the reliable operation of the BPS.
- If consumer side DER and BTM technologies raise energy demand during evening peak hours they may contribute to rising levels of unserved load and thus affect reliability.
- The extent that the level of resource flexibility on the BPS will need to increase or decrease will be dependent on how consumer side DER and BTM resources are used. As electrical storage technologies continue to advance, the dependence on conventual resources that provide flexibility, such as gas fired, may decrease in the future.
- Current data sources and models used at the national and regional planning areas have not developed to a level where rapidly changing consumer values and tastes can be assessed for predictions on potential impact on the power system.
- There may be some regulatory policies (related to demand-side management, market pricing signaling, and others) which if implemented with appropriate infrastructure (advanced metering, consumer engagement communications) can influence how customer-side resources are used. How different state and provinces arrive at those policies and implement them we expect will play out overtime. Whether or when an optimal WECC wide approach emerges in this area is unclear.

We anticipate that following the publication of this report that the Scenario Development and Studies Subcommittees within WECC will during the coming year determine the nature and focus on follow on studies to this work, and in that process incorporate any changes to the key questions driving the scenario analyses forthcoming.

Key Analytic Takeaways

Load Growth

- In addition to the four Scenarios, a 2038 Reference Case was derived from the 2028 ADS PCM by extending the load profiles of the 2028 ADS PCM another ten years to the target date of 2038. The Reference Case was created to serve as a comparative basis in the analysis of the Scenarios. The net system load CAGR for the Reference Case was 1.76%.
- NREL used a very empirical bottoms-up approach to derive the Demand-Side Scenarios for the Electrification Futures Study based on different levels of customer adoption and technology advancement in the Transportation, Commercial, Residential, and Industrial sectors. At higher levels of electrification, the diurnal shapes were spikier where electrification growth was more concentrated at evening peak. The transportation sector currently accounts for less than 1% of electricity demand but accounts for nearly 30% of total energy consumption in the U.S. Most of the electrification growth comes from that of electric vehicles (EV). Accelerated growth in the transition of the transportation sector to EV would have a monumental impact on the BPS. Other technology types captured include commercial and residential heat pumps. Net load demand inclusive of solar and wind is even more severe, creating serious operational challenges. In an ideal world, the net load demand would be nearly flat (e.g., average demand equal to evening peak demand). In this regard, strategies to smooth net load demand may offer the greatest potential to address the risks of a highly electrified future. Demand-side management strategies that include shifting charging times of electric vehicles from evening peaks to when energy production from solar is high would be highly effective.
- Electrification in this study was focused end-use equipment that has the potential to transition from non-electric fuel sources to electrification. Load growth, however, will be impacted by other consumer choice technologies that may evolve. Further research needs to be done to better quantify consumer choice models and their impact on load growth.

Unserved Load

- Unserved load occurred at evening peak in all the Scenarios and the Reference Case, primarily in summer. The main contributors to the occurrences of unserved load were diurnal electrification demand disproportionately higher at evening peak, displaced baseload resources (primarily coal fired), and higher penetrations of variable resources which were much less effective at providing resource flexibility at evening peak when needed most (primarily solar). The occurrence of unserved load was worse in Scenarios 2 and 3 which had much higher electrification load levels driven by assumed higher levels of customer adoption. Load levels for the Reference Case and Scenarios 1 and 3 were comparably close. Unserved load in the Reference Case, however, was higher than that of Scenarios 1 and 3 primarily due to the absence of resource flexibility from dispatchable DER-EV in the Reference Case. Though dispatchable DER-EV amounted to less than 2% of total annual energy production, it was highly effective at providing resource flexibility to mitigate the risk of unserved load at evening peak. Dispatchable DER-EV is effectively electrical storage so, by extension, electrical storage is judged to be highly effective at providing resource flexibility and should be investigated in further detail as a follow-up study.

- There appears to be a close relationship between unserved load, diurnal evening peak demand levels, and the ratio of resource flexibility (e.g., gas fired and electrical storage) to resources variability (e.g., wind and solar). Despite a total resource portfolio capacity of 395 GW, a demand threshold of 185 GW was observed across all study cases representing an upper limit of load demand that, when exceeded, unserved load would occur. The candidate resource portfolio used across all studies was largely based on the Mid-Case Resource Portfolio. It was further observed that by maintaining a ratio of 58% of flexible resources to the total resource dispatch at evening peak, the occurrence of unserved load could largely be avoided in the simulations. This ratio is, however, dependent on the diurnal demand shapes, the level of variable generation in the resource portfolio, and the SFT rules for commitment and dispatch of resource flexibility. This ratio of 58% is an example of how adjustments to SFT commitment rules could be made to reduce the risks of unserved load, but at increased commitment costs which ultimately get passed on to the consumer.

Resource Mix, Commitment, and Dispatch

- Growth in future energy needs is largely met by growth in gas fired generation, solar PV, and wind, proportionally in that order.
- Coal fired generation was completely displaced due to scheduled retirements and a CO_2 emission cost of $55/ton.
- Dependence on natural gas fired generation for energy production and resource flexibility will increase with the displacement of baseload resources (primarily coal fired), and increases in variable generation, primarily wind and solar. Close to 40% of the total energy production needs and close to 60% of the resource flexibility needs was provided by natural gas fired generation. The energy production and dispatch from other resource types were largely constant with natural gas fired generation tracking load variability.
- While the annual energy production from solar was roughly 12% across all study case simulations, the level of dispatch from solar at evening peak demand, when unserved load occurred, was less than 1% of the overall dispatch, which translates to an ELCC at evening peak demand of less than 2% for solar as compared to an ELCC at evening peak demand for flexible resources of approximately 95% or more. The commitment and dispatch of solar as a price taker also increased the occurrences of energy spillage when load demand was low and dispatch from solar was high. A coordinated operational strategy between solar, electrical storage, and demand-side management would greatly increase the value proposition for all three dispatch types where adequate levels of resource flexibility would be maintained across all load demand levels.
- The incremental increase or decrease in energy production to track load came primarily from gas fired generation and electrical storage (to a lesser extent) as observed across all study cases.

The energy production from other resource types generally remained constant to that of the Reference gas. This further illustrates the dependence on gas fired generation and electrical storage for resource flexibility.

- The diurnal charging and dispatch patterns of electrical storage become more uniform and predictive (less random) as dependence on resource flexibility increases. Optimizing charging and dispatch of electrical storage around evening peak demand and increasing the duration during which resource flexibility from electrical storage at evening peak is available is critical and should be examined in greater detail in future studies.
- The diurnal shapes of electrical storage became extremely uniform and predictive at higher electrification load levels as electrical storage was heavily used as a flexible resource during periods when unserved load occurred. Opportunities may exist, however, to better optimize the flexibility of electrical storage by adjusting the charging and dispatch times. This warrants further study.
- Saturation of resource flexibility occurred for the study simulations at demand levels above 180 GW. Adjustments to SFT commitment rules for more resource flexibility could increase the 180 GW threshold by increasing the number of flexible resources committed and available for dispatch at evening peak, but at a higher production cost.

Distributed Energy Resources (DER)

- The bulk of DER will probably double but likely will not exceed 20% of the total energy production of the portfolio, unless the growth in electrical storage increases. In the absence of electrical storage, the dependence on the BPS for reliability assurance will likely increase rather than decrease with an increase in DER from solar PV.
- Dispatchable DER-EV is less effective at mitigating unserved load at higher electrification load levels because the overall resource flexibility of the SCRP is quickly exhausted at hourly demand levels above the 180 GW threshold.

Inter-Regional Transmission

- California remains as having the largest share of the total energy requirement in the Western Interconnection at roughly 30% and is the largest importer. The Western Interconnection generally becomes more dependent on the Basin and the Southwest for energy production. The Rocky Mountain region switches from being a net exporter of energy to be a net importer of energy due largely to the displacement of coal fired generation. Exports from the Southwest and Basin will increase and exports from the Northwest will decrease during winter. The converse is true during summer. With the resultant changes in energy production mixes, the interregional path use in these regions will increase.
- Reliance on surpluses of generation in the Southwest and Basin regions increases path use out of these regions.

Economics

- There is a close correlation of LMP price spikes with unserved load. In the PCM, an LMP price maximum of \$4000/MWh and consistently occurs when unserved load occurs. In the absence of unserved load, the LMP generally averages less than \$40/MWh and fluctuates in a range between \$80/MWh and \$0/MWh. The upper bound of this range is due to congestion while the lower bound is due to energy spillage driven by higher levels of energy production from solar at lower levels of load demand.
- The LCOEs of new resources that were committed and dispatched ranged between \$100/MWh and \$25/MWh with exception of natural gas fired combustion turbines (NG-CT). The LCOE of new NG-CTs was above the \$100/MWh upper bound of this range but were committed and dispatched to meet flexibility needs. Average annual energy production from NG-CTs is low which leads to higher LCOEs. Despite this, NG-CTs have extrinsic value in the form of flexibility which is not reflected in their LCOEs but demonstrated in the PCM simulations.
- LCOEs for life extension of resources were estimated by assuming a 10-year economic life to that of full economic life of new resource additions (generally between 20 and 40 years). The results yield life extension LCOEs that were generally around 60% of new resource additions and representative a qualitative estimate of the limits of life extension investments before diminishing returns result. The reader should be cautioned, however, that these estimates for life extension LCOEs are very qualitative based on a simplistic approach but may have value in terms of initial screening of life extension options before doing a more quantitative analysis.

Environmental

- CO_2 emissions in 2038 decreased by roughly 30% from that of 2018, from 0.27 billion metric tons to 0.19 billion metric tons, primarily due to the displacement of coal.
- Water consumption for thermal cooling in 2038 decreased by roughly 19% from that of 2018, from 190 billion gallons to 154 billion gallons, primarily due to the displacement of coal.

8. Looking Forward

The main purpose of this study was to shed light on some of the questions posed by the Scenarios. There was never any intent or notion that this study would be find definitive answers to all the questions posed.

A guiding principle of the long-term planning effort of this study is not to predict the future but, rather, gain a better understand of the range of plausible energy futures and the underlying drivers that may influence that future. This principle also applies to the underlying assumptions and forecasts applied to the creation of the study cases. For example, no one can claim with absolute certainty that one forecast for fuel price, as an underlying assumption, is any better or worse than any other. What is important, however, is the recognition that any variations in combinations of underlying drivers (e.g., fuel prices, emission prices, efficiencies, portfolio mix) will yield different results. In a twenty-year planning horizon, there are no absolutes as to the underlying assumptions nor the results. In this context, many of the forward-looking recommendations provided in this section are provided as recommendations for further sensitivities around the underlying drivers and how they may affect study results.

Another guiding principle of scenario analysis is that it is a learning process over time. In this regard, a learning loop process is used to formulate and investigate focus questions and to use the results to sharpen thinking and lead to more useful questions about the changes and uncertainties at issue. In this context, many of the recommendations from this study are in the form of new questions that may warrant further study.

- Sensitivities around demand-side management to smooth diurnal load shapes by shifting load from periods of evening peak demand to lower load demand periods when energy production from solar is high and when energy spillage is prevalent should be studied further. Methods to promote demand-side management should be investigated further as well, whether through policy, markets, industry, or consumer choice mechanisms.
- Sensitivities around fuel prices relative to different resource portfolio scenarios, economic assumptions, and other factors that affect production cost should be studied further. There are many factors that will influence the production costs of resources, how resources are committed and dispatch, and the price spreads between resource technology types. When price spreads between resource technology types are narrow, the commitment and dispatch of resources are much more sensitive underlying assumptions that factor into production cost. When price spreads are wide, the commitment and dispatch between resource types are less sensitive. In this context, it is important to further study the inter-relationships between underlying factors (such as fuel cost, emission costs, efficiencies, and resource portfolio mix) that determine how resources are committed and dispatched to better understand how simulation results may change.
- Sensitivities around resource flexibility, which has the potential of committing more resources that can provide additional dispatch flexibility at evening peak demand periods, should also be studied further as well as methods to assure adequate resource flexibility at evening peak demand, whether from policy, markets, industry, or consumer choice.
- Sensitivities around electrical storage and its effectiveness and viability to provide resource flexibility at evening peak demand, should also be studied further as well as methods to optimize electrical storage with solar, whether from policy, markets, industry, or consumer choice.
- Extend the ADS to include a twenty-year planning horizon including the necessary quality control and peer review mechanisms.
- Create demand-side load ensembles, either adapted from the work of the National Labs or created from scratch, based on underlying drivers developed through scenario planning

methods that would then be available to WECC and stakeholders to mix and match in study case creation as an augmentation to the ADS.

- Create resource portfolio ensembles, either adapted from the work of the National Labs or created from scratch, based on underlying drivers developed through scenario planning methods that would then be available to WECC and stakeholders to mix and match in study case creation as an augmentation to the ADS.
- Sensitivities around micro-grids and their potential to hinder or improve reliability assurance of the BPS should be studied further as well as methods to assure reliable integration of micro-grids to the BPS, whether from policy, markets, industry, or consumer choice.
- With the accelerated growth in vehicle electrification, was to optimally integrate electric vehicles (EV) to the BPS, including infrastructure, need to be studied further, whether from policy, markets, industry, or consumer choice.
- Further study is required to better understand how DER may evolve and their potential to hinder or improve reliability assurance of the BPS as well as methods to assure reliable integration of DER, whether from policy, markets, industry, or consumer choice.
- Further study is required to better understand how customer choice may evolve and the BTM implications to reliability assurance of the BPS.
- Sensitivities around the simultaneous feasibility test (SFT) for the commitment and dispatch of resources to better understand how the SFT may need to be optimized to accommodate transformations in the BPS.

Appendix A – Acknowledgements

WECC would like to acknowledge and thank the participants on the WECC Scenario Task Force (WSTF) whose efforts were instrumental in crafting the scenarios and providing guidance in the assessment process. Special thanks to:

Michael Bailey, who has lead the twenty year long term planning efforts since inception at WECC, was principle investigator of the scenario studies, guided the WSTF through the process of transforming scenario narratives into study cases, performed the simulations, analyzed and interpreted the results, drafted the initial report, and reworked the draft to accommodate edits and comments received from the WSTF.

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Table 14: WECC Scenarios Task Force (WSTF) Participants

Member	Organization
Frank Afranji	Northwest Power Pool
Ravi Aggarwal	Bonneville Power Association

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Carl Zichella	Natural Resources Defense Council

Appendix B – Acronyms, Abbreviations, and Definitions

Acronyms and abbreviations used in this report are listed in Table 15.

Table 15: List of Acronyms and Abbreviations

Acronym	Definition
2028 ADS P2v2.0	2028 Anchor Data Set (Phase 2 version 2.0)
ADS	WECC Anchor Data Set
BPS	**Bulk Power System**: which refers to the transmission level bulk power system.

Acronym	Definition
BTM	**Behind-the-Meter**: A generating unit or multiple generating units at a single location (regardless of ownership), of any nameplate size, on the customer's side of the retail meter that serve all or part of the customer's retail load with electric energy. All electrical equipment from and including the generation set up to the metering point is behind the meter. This definition does not include BTM resources that are directly interconnected to BPS.
CAGR	Compound Annual Growth Rate
Commitment	A decision, usually day-ahead, to commit a generator to run. Commitment of a generator to run does not necessarily predetermine the exact hourly dispatches of the generator when it runs.
Consumer Choice	Consumer Adoption of New Electricity Service Options
Demand-Response	Measures that pursue the temporary reduction of electricity consumption by the consumer (discretionary and limited in time) during periods of peak demand and that it is done in exchange for economic incentives by the load serving entity.
Demand-Side Management	Includes all demand reducing measure of demand-response and energy efficiency.
DER	**Distributed Energy Resource**: Any generation resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the BPS.
DER-EV	Distributed Energy Resources represented by high electric vehicle (EV) penetration
DG	**Distributed Generation**: Any non-BPS generating unit or multiple generating units at a single location owned and/or operated by 1) the distribution utility, or 2) a merchant entity.
Dispatch	The amount of MW power that a generator is scheduled to provide for a given hour. A generator must generally be committed before it is available for dispatch.
DR	**Distributed Resource**: same as DER.
DSGRID	The NREL demand-side grid model: at tool that uses a suite of bottom-up engineering models across all major economic sectors—transportation,

Acronym	Definition
	residential and commercial buildings, and industry—to develop hourly electricity consumption load profiles.
EE	**Energy Efficiency**: When modeled on the supply, represents an hourly resource that service as a proxy for load demand management (e.g., smoothing evening peaks, increasing load factors)
Energy Spillage	Generation in excess of load that must be curtailed to maintain an energy balance between generation and load.
EFS	The NREL Electrification Futures Study
ELCC	Effective Load Carrying Capability
Electrification	The shift from any non-electric source of energy to electricity at the point of final consumption. [1]
Energy Spillage	Generation dispatch in excess of load demand that must be curtailed to maintain an energy balance for an integrated hour of a PCM simulation.
EP	EnergyPATHWAYS: a bottom-up stock-taking tool of all infrastructure that consumes, produces, delivers, or converts energy. [23]
Flexibility	The extent at which a resource can respond to variability in the load and generation balance. Flexibility encompasses several operational factors such as having ELCC and ramping capability when needed and providing contingency reserve to mitigate against the risks of large loss of generation our transmission and regulation reserve to respond to smaller fluctuations in load or variable generation.
GHG	**Green House Gas**: gases that absorb and emit radiant energy within the thermal infrared range. Greenhouse gases cause the greenhouse effect (e.g. global warming) on planets. The primary greenhouse gases in Earth's atmosphere are carbon dioxide, methane, nitrous oxide, and ozone.
HVAC	Heating, Ventilation, and Cooling
IRP	Integrated Resource Plan: a roadmap that utilities use to plan out generational acquisitions over five, 10, or 20 years (or more). Essentially, an IRP states: “We have the planned resources to meet our future energy needs.“
LCOE	Levelized Cost of Energy is a measure of the average net present cost of

Acronym	Definition
	electricity generation for a generating plant over its lifetime. The LCOE is calculated as the ratio between all the discounted costs over the lifetime of an electricity generating plant divided by a discounted sum of the actual energy amounts delivered.
LMP	Locational Marginal Price ($/MWh)
Load Factor	The ratio of average demand to peak demand over a given period.
LSE	Load Serving Entity
Mid-Case Resource Portfolio	Refers to the NREL Mid-Case Standard Scenario. [5]
NEV	No dispatchable DER-EV enabled
NREL	National Renewable Energy Laboratory
NTC	No Transmission Path Constraints enforced
OATT	Open Access Transmission Tariff
PCM	Production Cost Model
Peak Demand	The largest level of load demand that occurs during a given period. Diurnal peak demand generally occurred around 7:00 p.m. in the load profiles used in the simulation.
RCCRP	Reference Case Candidate Resource Portfolio
Reference Case	WECC 2038 Reference Case
Rooftop Solar PV	**Rooftop Solar PV**: Energy production provided by rooftop solar photo voltaic resources, either commercial or residential that is not connected directly to the BPS.
RPS	**Renewable Portfolio Standard**: a regulatory mandate to increase production of energy from renewable sources such as wind, solar, biomass and other alternatives to GHG emitting electric generation.
SC1	Scenario 1: Open Markets with Limited Customer Choice
SC2	Scenario 2: Open Markets with High Levels of Customer Choice
SC3	Scenario 3: Reliability and Cost Policy Driven with Restricted Customer Choice

Acronym	Definition
SC4	Scenario 4: Reliability and Cost Policy Driven with High Levels of Customer Choice
SCRP	Scenarios Candidate Resource Portfolio
Scenarios	WECC 2038 Scenarios
SDS	Scenario Development Subcommittee
SFT	**Simultaneous Feasibility Test:** rules associated with the day-ahead commitment of resources that must be met to assure that adequate resources will be available to meet the day-of dispatch needs including that of hourly energy balance, ramping, reserve, and flexibility.
Storage ES	**Electrical Storage**: An energy storage device or multiple devices at a single location (regardless of ownership), on either the utility side or the customer's side of the retail meter. May be any of various technology types, including electric vehicle (EV) charging stations.
TOU	Time-of-Use (related to diurnal load demand)
WEV	With dispatchable DER-EV enabled
WSTF	WECC Scenario Task Force
WTC	Transmission Path Constraints enforced

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Appendix D – Assumptions, Tools, Models, Methods, and Data

Additional information on the assumptions, tools, models, methods, and data beyond what was described in the report body is provided in this Appendix.

Tools, Models, Methods, Data

GridView: For studies within the Western Electric Coordinating Council territory, GridView provides an industry-accepted simulation approach. The advanced analysis combines generation, transmission, loads, fuels, and market economics into one integrated framework to deliver location dependent market indicators, transmission system measures and power system reliability and market performance indices. It provides invaluable information for both generation and transmission planning, operational decision making and risk management. GridView uses state-of-the-art modeling technology to simulate security-constrained unit commitment and economic dispatch. It produces unit commitment and economic dispatch that respect the physical laws of power flow and transmission reliability requirements. As such, the generation dispatch and market clearing price are feasible market solutions within real power transmission networks. [21]

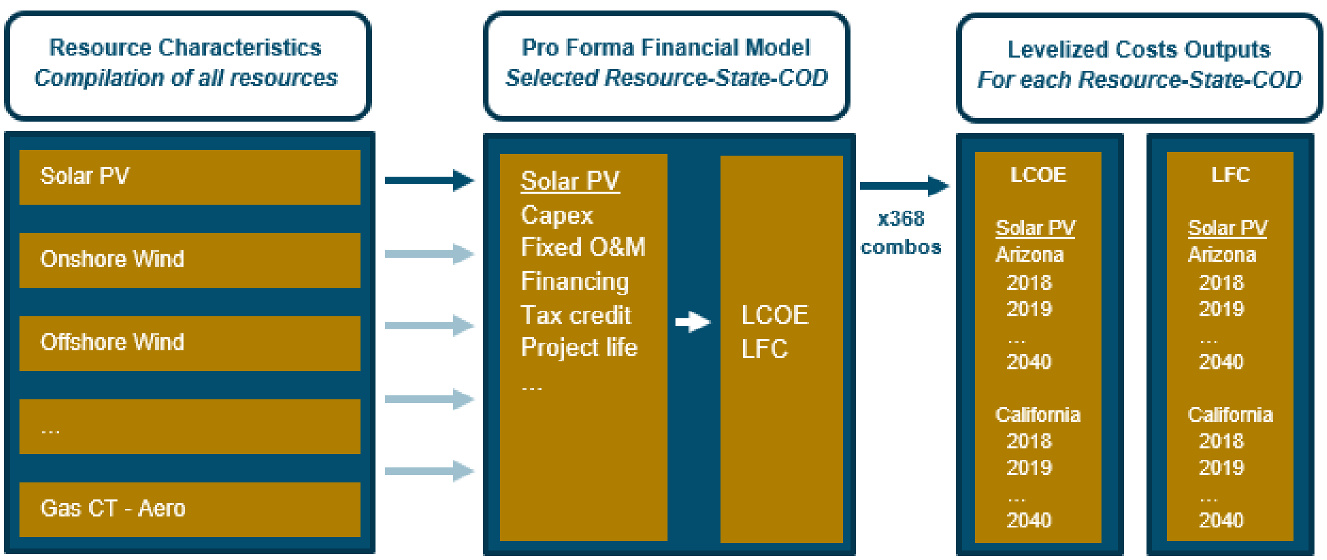
WECC Generation Capital Cost Tool: In 2009, WECC commissioned E3 to develop a tool to quantify capital costs of new electric generation technologies.8 Since then, E3 has provided WECC with several updates to the tool as technology trends have changed, usually at the starts of new biannual study cycles. The latest updates to the tool were provided to WECC in June of 2019. The WECC Generator

Capital Cost tool is openly available to the public. The tool is used by WECC to quantify total prospective costs of new generation by combining variable and fixed costs as shown in Figure 84.

Figure 84: Quantifying Total Prospective Cost of New Generation

The WECC Generator Capital Cost tool has three key components: 1) cost inputs for the different resources, 2) cost levelization in a pro forma financial model, and 3) the cost levelization output summaries, as shown in Figure 85.

Figure 85: Key Components of WECC Generator Capital Cost Tool



Resource costs are typically quoted in either upfront capital costs ($/kW) or levelized costs ($/MWh) that are indicative of likely PPA prices for renewables. Levelized costs include several other cost factors and assumptions beyond the project's upfront capital cost:

- **Financing costs**: cost of capital, financing lifetime, tax rates and incentives.
- **Operating costs**: fixed and variable O&M of plant operations ("opex"), including fuel.
- **Performance assumptions**: amount of energy generation over which fixed costs are spread, i.e. average capacity factor, is a major driver of LCOE.

The pro forma model in the tool is a discounted cash flow model that calculates levelized costs of energy ($/MWh) or capacity ($/kW-yr) under typical project financing structures as shown in Figure 86.

Figure 86: Pro Forma Model for Calculating Levelized Costs

PowerWorld: tool is an interactive power system simulation package designed to simulate high voltage power system operation on a period ranging from several minutes to several days. The software contains a highly effective power flow analysis package capable of efficiently solving systems of up to 250,000 buses. The PowerWorld tool was used in the creation of scenario cases and to perform sanity checks on the PCM results.

The NREL Studies: NREL conducts credible, objective analysis, develops tools, and builds data resources that inform decision makers of trends and transitions toward a secure, clean, and affordable energy future. WECC leverages the work of the National Labs in WECC's own studies to take advantage of the expertise that the labs offer. In the Scenario studies specifically, WECC leveraged the work of NREL that includes:

- Electrification Futures Study [1]
- Demand-Side Scenarios [22]
- Standard Scenarios [5]
- Annual Technology Baseline [6]

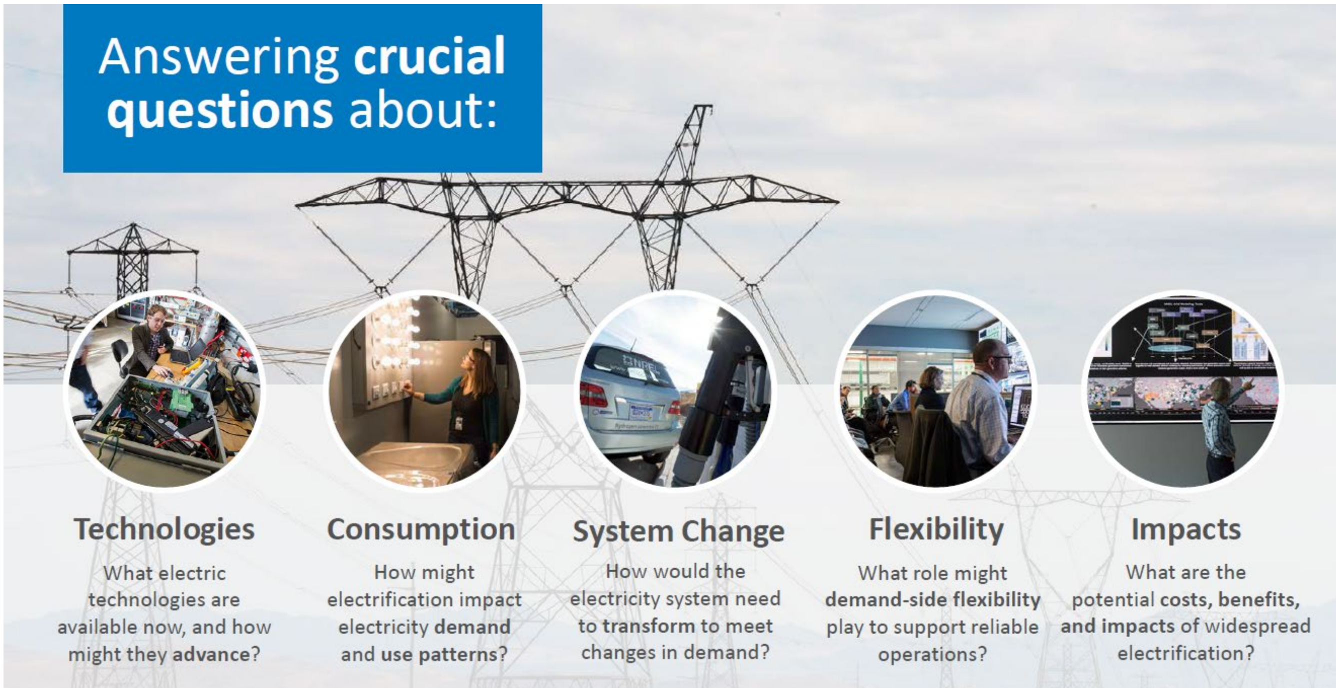
Load Models

The modeling assumption that went into this report were vetted through the WECC Scenario Task Force (WSTF). The effort of which was to transform the Scenario narratives into data and models that can be studied. Models and methods chosen were focused on the Scenario Matrix themes. Tools and models used to perform this study included a production cost models, power flows, capital expansion tools, the WECC Anchor Data Set ADS P2v2.0 and data provided by NREL as part of the Electrifications Futures Study (EFS).

To evaluate potential reliability risks associated with various futures for the Western Interconnection, it was necessary to define the load profiles that were representative of various levels of customer adoption of new service options. To do so, WECC and the WSTF turned to the National Renewable Energy Laboratory (NREL).

There are crucial questions that must be answered to plan for an electrified future as shown in Figure 87.

Figure 87: Crucial Questions for an Electrified Future [22]



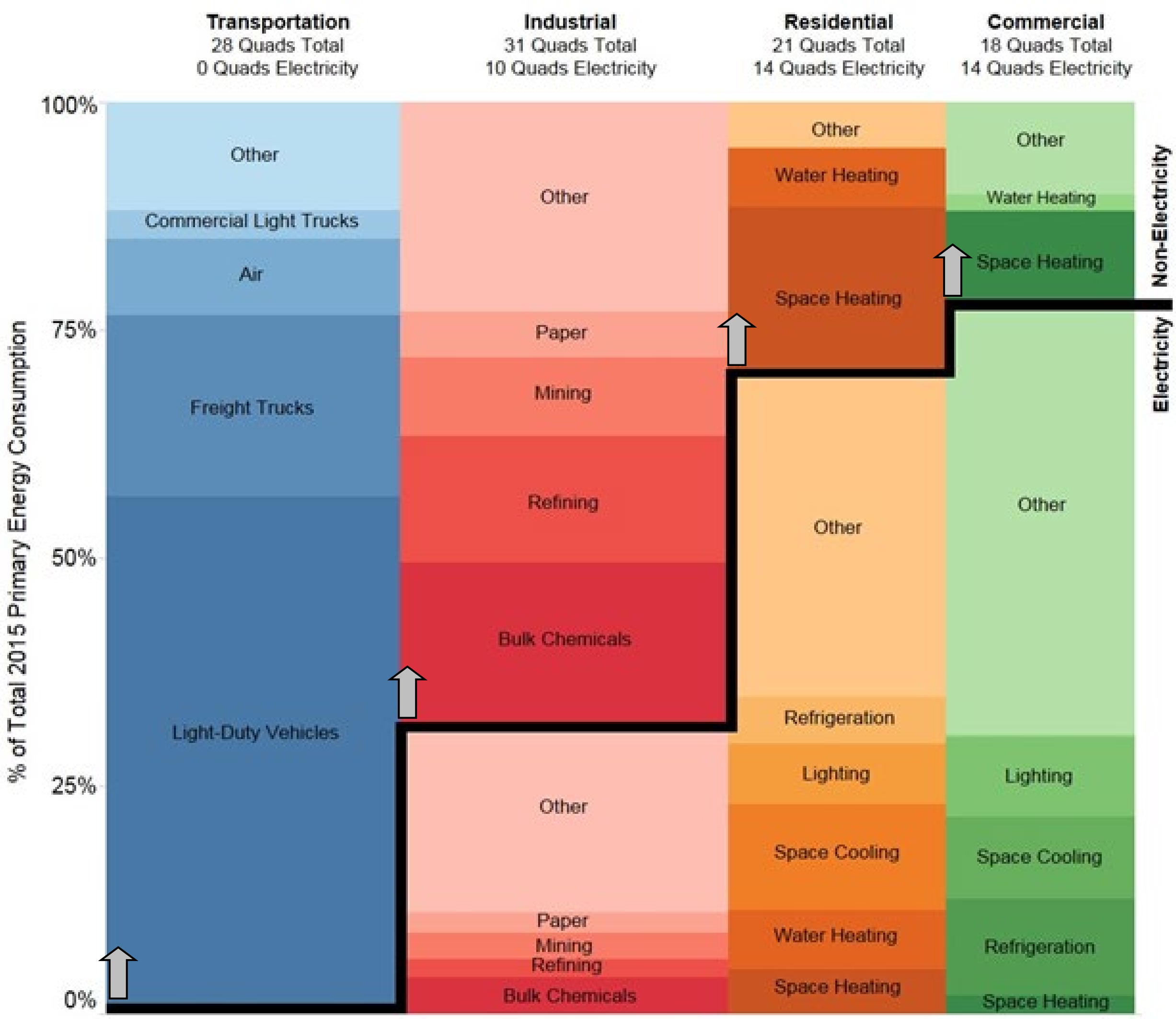
A bottom-up approach to consumer choice modeling using EnergyPATHWAYS (EP) was used to answer these crucial questions. [23] EP is a bottom-up stock-taking tool of all infrastructure that consumes, produces, delivers, or converts energy. Annual sales shares in each scenario were developed through expert judgment from the EFS authors based on analysis of current trends and insights from other studies as well as from consumer choice models. These sales shares are input to the tool, which tracks service demand changes, equipment stock turnover to meet those changes and consequential final energy and electricity use of vehicle fleets; appliances; heating, ventilation, and air conditioning systems; industrial machinery; and other types of energy-consuming equipment over time.

To answer the questions shown in Figure 87, NREL developed the Demand-Side Scenarios as part of the EFS. [**1**] In the context of the EFS and, by extension, the Demand-Side Scenarios, electrification is the shift from any non-electric source of energy to electricity at the point of final consumption.

The electrification focus was further classified as energy transition where electrification is defined as the substitution of electricity for direct combustion of non-electricity-based fuels (e.g., gasoline and natural gas) used to provide similar services. In other words, the energy transition focus was on electric technologies that can be used to replace existing non-electric ones—e.g., electric vehicles for internal combustion engine vehicles, heat pumps for natural gas space heating, and electric induction furnaces for fuel-fired industrial furnaces. Yet to-be-developed electric-based technologies were not included in the analysis.

End-use was split up into four sectors: transportation, industrial, residential, commercial as shown in Figure 88.

Figure 88: 2015 Energy Consumption Shares in 2015 [1]



The NREL Demand-Side Scenarios were created to explore the impacts of widespread electrification in all U.S. economic sectors—commercial and residential buildings, transportation, and industry where:

- The **objective** of the Demand-Side Scenarios is to characterize changes to end-use sectors under futures with increasing levels of electrification and quantify how electrification impacts total electricity demand and consumption load profiles.

- The **approach** taken to create the Demand-Side Scenarios was bottom-up using a stock and energy accounting model (EnergyPATHWAYS). [23]
- **Used** to provide data for evaluating future electricity supply scenarios and to give researchers and decision-makers data and context to plan for an electrified energy system.

The Demand-Side Scenarios are multiple electricity consumption scenarios with variations along two primary dimensions: (1) end-use electric technology adoption and (2) electric technology cost and performance as shown in Table 16.

Table 16: NREL Demand-Side Scenarios Matrix [1]

	Slow Technology Advancement	Moderate Technology Advancement	Rapid Technology Advancement
Reference Customer Adoption	Reference Adoption, Slow Technology Advancem SC3	Reference Adoption, Moderate Technology Advancem SC1	Reference Adoption, Rapid Technology Advancement
Medium Customer Adoption	Medium Adoption, Slow Technology Advancement	**Medium Adoption, Moderate Technology Advancem** SC4	Medium Adoption, Rapid Technology Advancement
High Customer Adoption	High Adoption, Slow Technology Advancement	High Adoption, Moderate Technology Advancem SC2	High Adoption, Rapid Technology Advancement

Along the adoption dimension, NREL modeled three levels of electric technology adoption and refer to these levels as Reference, Medium, and High electric technology adoption levels. For each of these adoption trajectories, NREL modeled three technology cost and performance projections, referred to as Slow, Moderate, and Rapid technology advancement projections. Because different levels of technology advancement can result in various equipment energy efficiencies as well as cost reductions, an assessment of overall electricity consumption must consider both the amount of adoption as well as the technology evolution. In all, NREL develop nine scenarios—three electrification levels times three technology advancements as shown in Table 16.

Along the two dimensions associated with NREL's Demand-Side Scenarios, the following assumptions apply:

Technology Advancement

- **Slow**: Assumes futures where electrification follows current trends without major advances. In many instances, the Slow Advancement cases follow reference projections developed by other organizations, such as the U.S. Energy Information Administration (EIA) in its Annual Energy Outlook (AEO) Reference case (EIA 2017a).

- **Moderate**: Falls between the Slow and Rapid projections. Moderate advancement reflects electric technology progress beyond current trends but not to the extent of Rapid. In other words, the Moderate projections consider additional R&D and technology innovation consistent with futures in which electrification outpaces reference projections.
- **Rapid**: Assumes futures in which public and private research and development (R&D) investment in electric technologies spurs technology innovations, manufacturing scale-up increases production efficiencies, and consumer demand and public policy yields technology learning. This projection does not reflect the maximal achievable advancement possibilities—which are impossible to predict—but it does reflect technology cost reductions, performance improvements, or both, relative to currently available options.

Customer Adoption

- **Reference**: Assumes the least incremental change and limited improvements in cost and performance.
- **Medium**: Falls between Reference and High projections. Medium adoption assumes widespread electrification among low-hanging fruit opportunities.
- **High**: Assumes transformation electrification where cost parities would likely result in substantial increases in adoption of new customer electrification options, primarily in terms of electric vehicles and commercial/residential heat pump technologies.

The dimensions of NREL's Demand-Side Scenarios coincidentally aligned well with the dimensions of WECC's Scenarios. As part of the scoping process for the WECC Scenario studies, the WSTF matched each WECC Scenario load profile to a corresponding NREL Demand-Side Scenario as shown in Table 17.

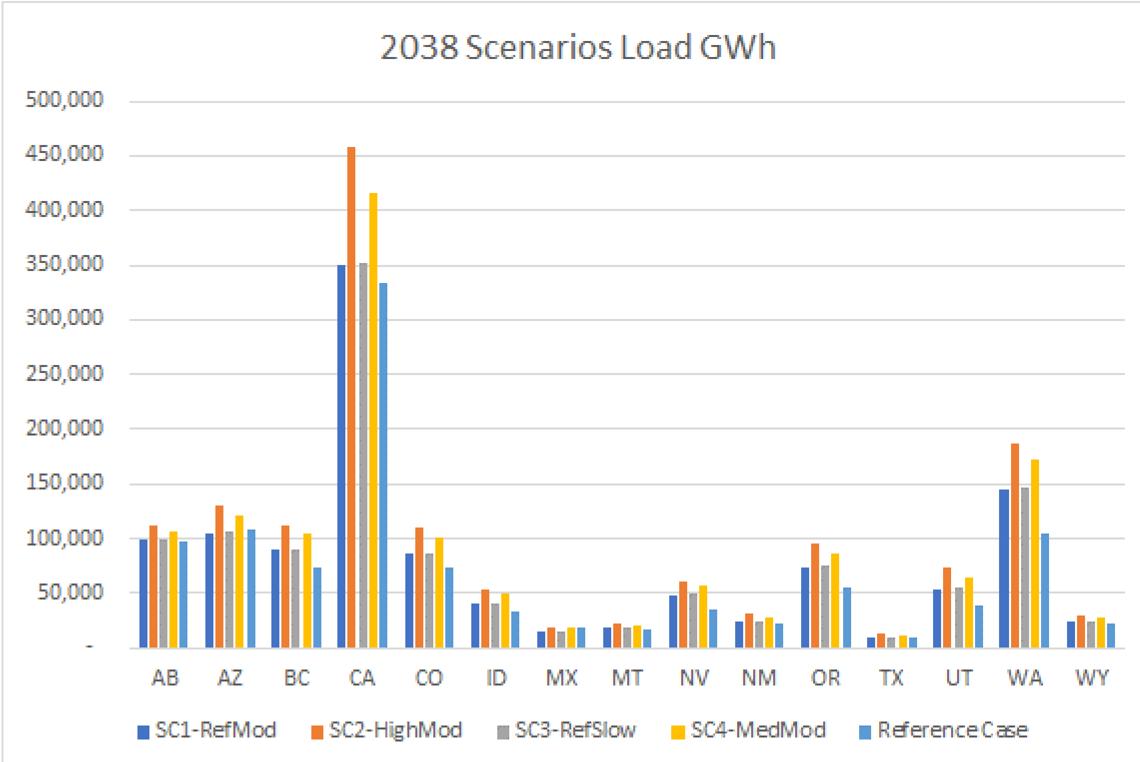
Table 17: WECC Scenarios Load Profile Selections

	Slow Technology Advancement	Moderate Technology Advancement	Rapid Technology Advancement
Reference Customer Adoption	Reference Adoption, Slow Technology Advancement SC3	Reference Adoption, Moderate Technology Advancement SC1	Reference Adoption, Rapid Technology Advancement
Medium Customer Adoption	Medium Adoption, Slow Technology Advancement	**Medium Adoption, Moderate Technology Advancement** SC4	Medium Adoption, Rapid Technology Advancement
High Customer Adoption	High Adoption, Slow Technology Advancement	High Adoption, Moderate Technology Advancement SC2	High Adoption, Rapid Technology Advancement

A Reference Case was created to provide a basis for comparison of the Scenarios. The Reference Case load profiles were constructed by extending the load profiles of the 2028 ADS PCM another 10 years using compound annual growth rates (CAGR) obtained from integrated resource plans published by various balancing authorities in the Western Interconnection. .

The annual load requirements (GWh) by case and state are shown in Figure 89.

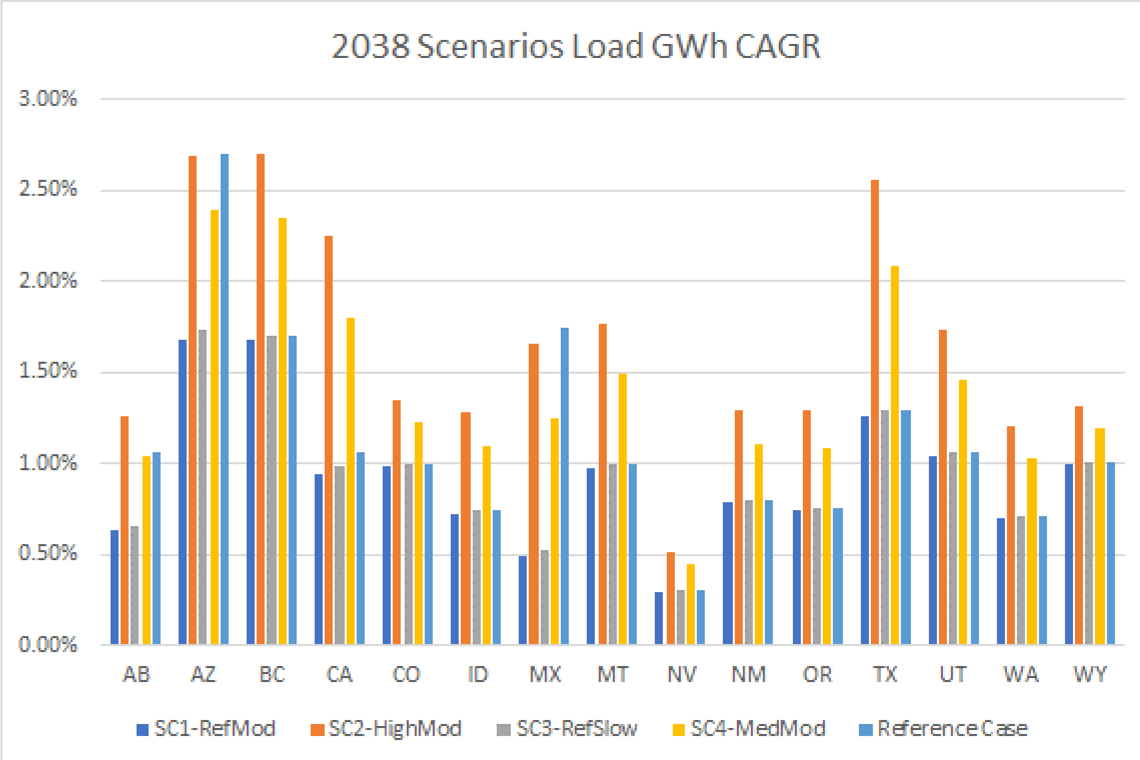
Figure 89: 2038 Annual Load Requirements by Case and State



As Figure 89 shows, load requirements for SC1 and SC3 are like that of the Reference Case where the load requirements for SC2 and SC4 are much higher. The reason SC2 and SC4 have higher load requirements than the SC1, SC3, and the Reference Case is that their load profiles are based on assumptions of higher customer adoption of new electricity service options as will be discussed later.

The load profiles for the Reference Case were produced by extending the load profiles of the 2028 ADS PCM another 10 years to 2038 using compound annual growth rates obtained from integrated resource plans published by various balancing authorities in the Western Interconnection as shown in Figure 90.

Figure 90: 2038 Annual Load CAGRs by Case and State



As Figure 90 shows, the CAGRs for SC1 and SC2 are closely aligned with those of SC1 and SC3 except for Arizona and Mexico where the CAGRs from their IRPs were more aligned with SC2 and SC4.

Generation Resource Models

The generation resource model used in the 2038 scenarios was derived from the 2028 ADS PCM model and the Mid-Case Resource Portfolio . [5] NREL developed 36 forward-looking resource portfolios referred to as the Standard Scenarios. These scenarios are designed to capture a range of possible generation resource portfolio futures considering a variety of factors that may affect these futures.

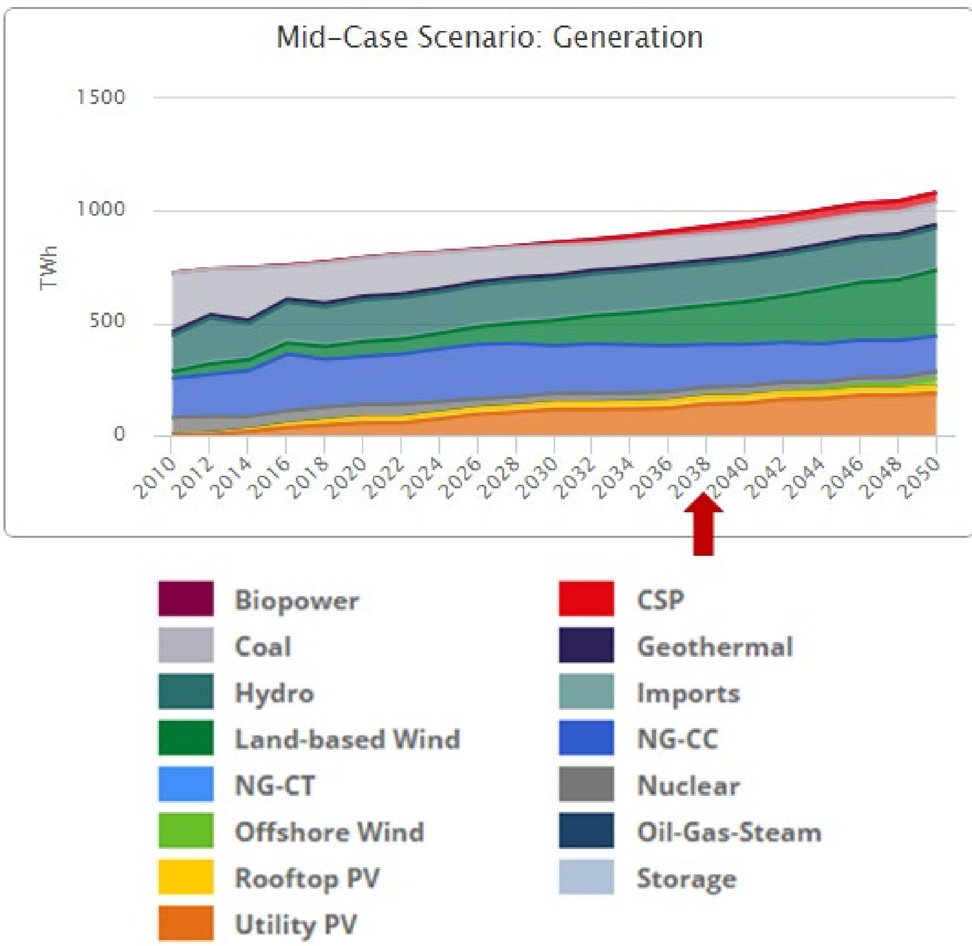
The resource portfolio chosen for the scenario studies was the Mid-Case Resource Portfolio which represents a reference portfolio that uses policies that are in place as of July 31, 2019 and include other default assumptions derived from the NREL's annual technology baseline. [6] The Mid-Case Resource Portfolio represents a Reference Case and provides a useful baseline for comparing scenarios and evaluating the trends.

The 2028 ADS PCM generation portfolio and its underlying performance and economic parameters were preserved. It was discovered that, in initial simulations, there was a large amount of resource retirements between 2028 and 2038 amounting to 26,813 MW, most of which was hydro located in the British Columbia (BC) region.

It was decided by the WSTF that the BC retirements were suspect. BC Hydro was contacted regarding these retirements and confirmed that the retirement dates were not correct and. WECC will work with the appropriate WECC Subcommittees to review retirement dates for all resources and make corrections to the ADS. In the interim, the retirement dates for BC hydro resources were pushed out to 2050 for all scenarios, in order to maintain a level of resource adequacy consistent with the most recent integrated resource plan (IRP) for BC Hydro. [4]

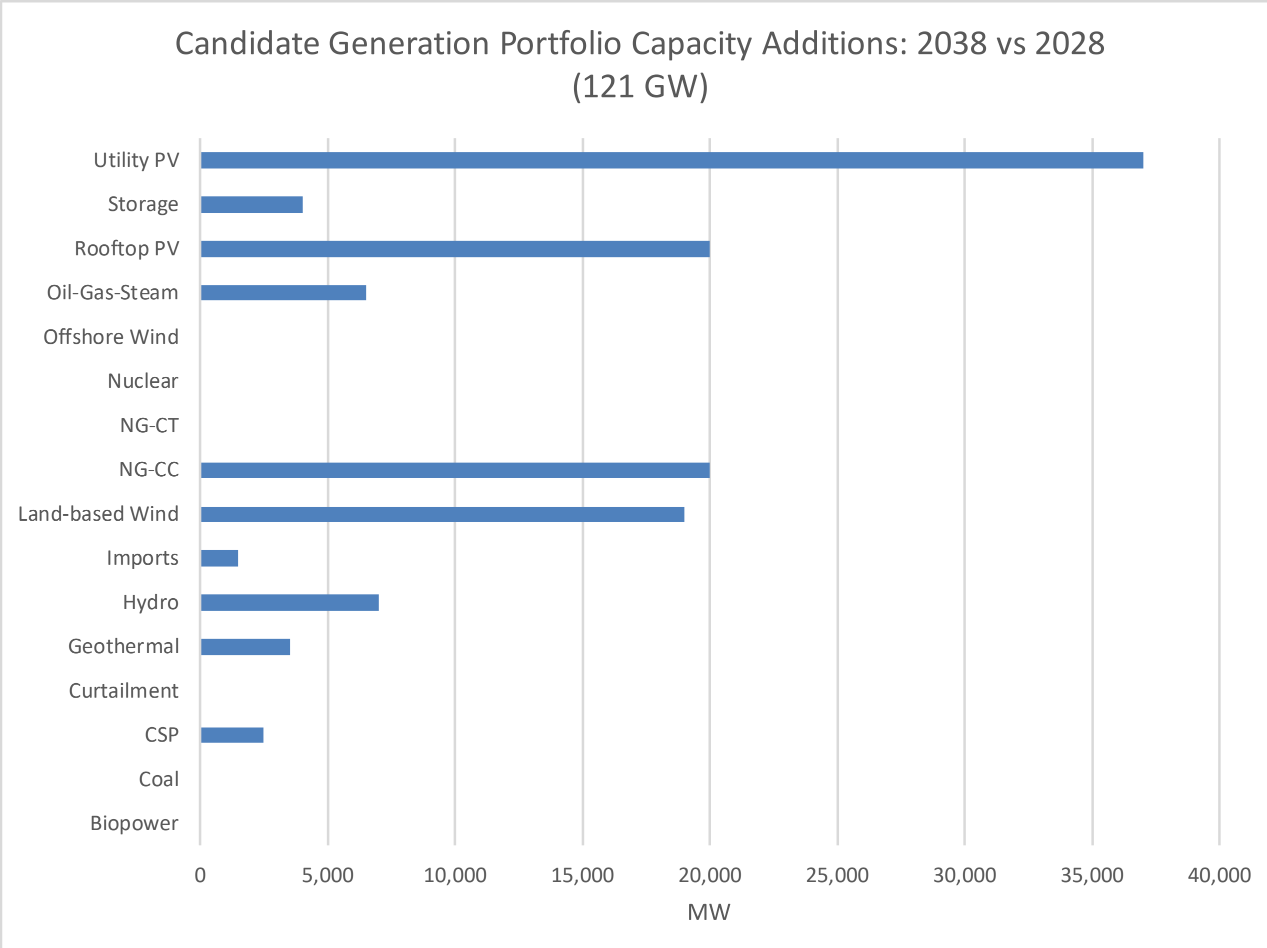
New resource types were added such that the 2038 generation candidate portfolio had the same resource mix as that of the Mid-Case Resource Portfolio as shown in Figure 91. [5] The resulting 2038 Scenarios Candidate Resource Portfolio serves as a baseline of candidate resources, new and existing, that the PCM can choose from for commitment and dispatch across all scenario PCM simulations.

Figure 91: Mid-Case Resource Portfolio [5]



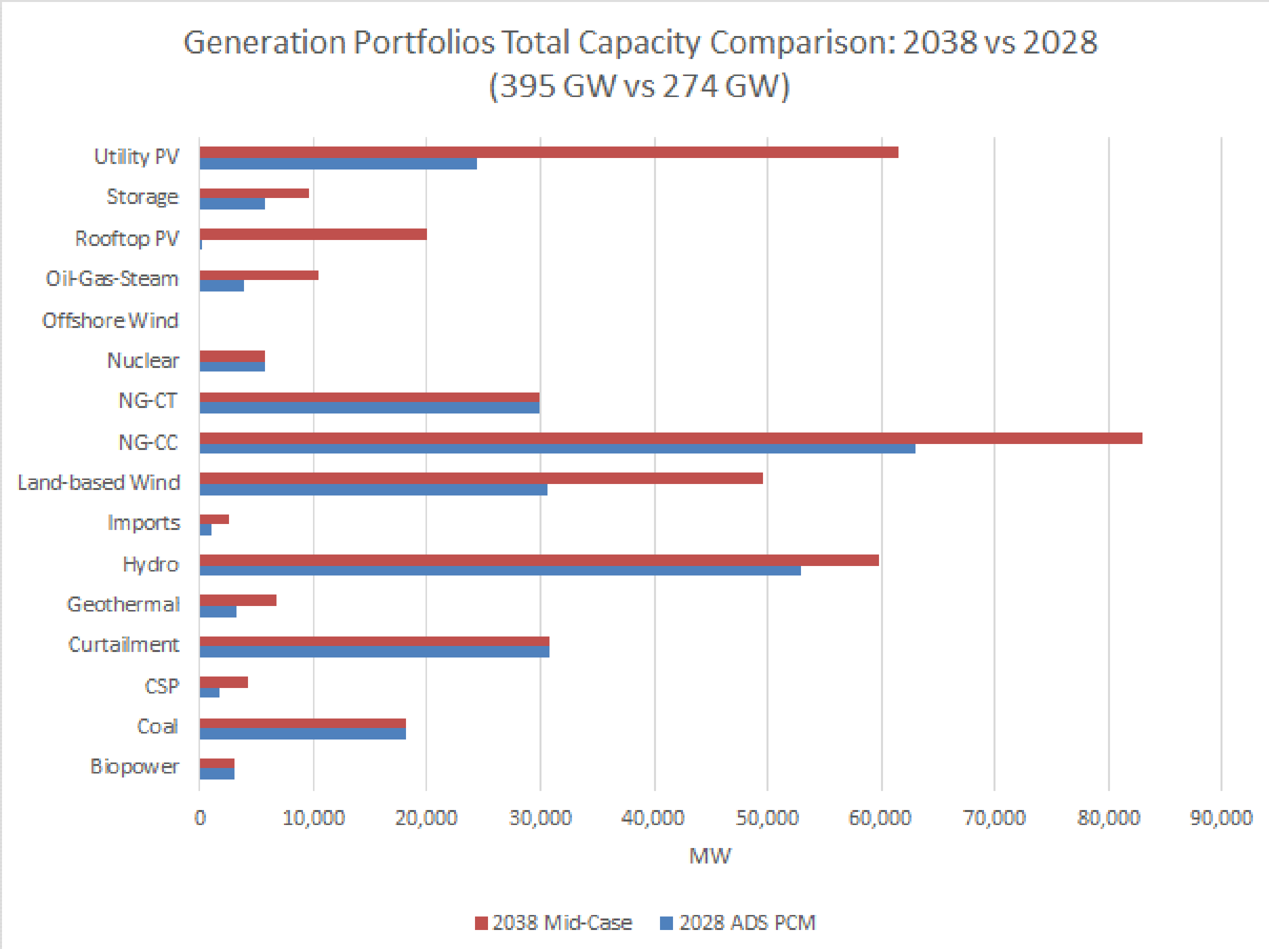
The resource additions to the 2028 ADS PCM such that the portfolio mix of the 2038 Scenarios Candidate Resource Portfolio was equivalent to the Mid-Case Resource Portfolio is shown in Figure 92.

Figure 92: 2038 Resource Additions to 2028 ADS PCM



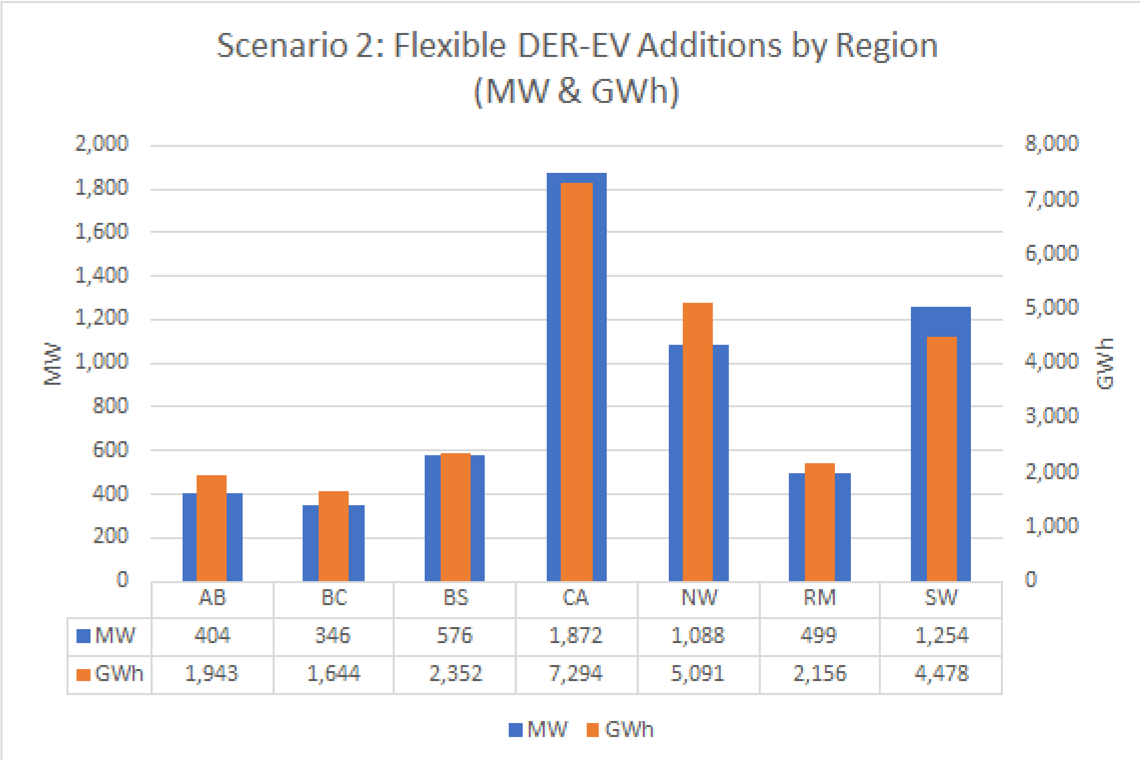
The total capacity of the 2038 Scenarios Candidate Resource Portfolio is 395 GW as compared to 274 GW for the 2028 ADS PCM as shown in Figure 93.

Figure 93: Total Generation Total Capacity Comparison, 2028 vs 2038



In addition to the Mid-Case Resource Portfolio additions described above, additional resources were added to the 2038 Scenarios Candidate Resource Portfolio for each scenario to represent the dispatchable DER in the form of electric vehicles (DER-EV) as previously discussed in this appendix under "Load Models." The capability of this dispatchable DER-EV varies hourly as it was derived by NREL from a bottoms-up approach using the DSGRID. [13] While dispatchable DER-EV was modeled in the Scenarios, it was not modeled in the Reference Case as since the load derived for the Reference Case was derived from the 2028 ADS PCM load growth patterns which and not from the NREL EFS demand-side loads selected for each of the scenarios. The DER-EV modeled for each scenario is unique depending on the NREL demand-side load selected for the scenario. The DER-EV additions for SC2 corresponding to the NREL "High Customer Adoption, Moderate Technology Advancement" is shown in Figure 94.

Figure 94: Scenario 2: dispatchable DER-EV Additions by Region



While SC2 had the largest amount of dispatchable DER-EV modeled, it still represented less than 2% of the total 2038 candidate resource portfolio capacity. DER-EV capacity for the other scenarios were closer to or less than 1%.

Transmission Models

The inter-regional transmission path assumptions in the 2028 ADS PCM are carried forward to the Reference Case and the Scenario Cases and are enforced as constraints. Since the focus of 20-year horizon studies is on inter-regional transmission paths, necessary reinforcements to intra-regional transmission (transmission not associated with a WECC interface path) are assumed and therefore not enforced as a constraint in the PCM. The inter-regional transmission paths are shown in Figure 95.

Figure 95: Western Interconnection Transmission Interface Paths

More information on WECC Interface Paths is available in the WECC Path Rating Catalog. [20]

Key Scenario Drivers

For the WECC Scenarios, the SDS agreed on the following initial set of key drivers shown below. Accompanying each key driver presented below is a description as to the approach, extent and/or limitation of how the key driver is captured in the modeling. A detailed discussion of these drivers can be found in the *WECC 2018-2019 Draft Scenarios for Horizon Year 2038 v0.1* report. [12]

1. **Changes in state and provincial electric energy market policies**
   *With the exception of a CO_2 cost of $55/ton, all state and provincial are captured exogenously in NREL's Regional Energy Deployment System (ReEDS) model which was used to construct the **Mid-Case Resource Portfolio**, as part of the NREL standard scenarios [5] , used in the WECC 2038 scenarios study.*
2. **Changes in federal electric energy market policies**.
   *Federal policy is captured exogenously only to the extent that it is captured within NREL's ReEDS model which was used to construct the **Mid-Case Resource Portfolio**, as part of the NREL standard scenarios, used in the WECC 2038 scenarios study. [5]*
3. **Evolution of customer-side energy supply technology and service options**.
   *The generation resource candidates used in the 2038 scenario studies was constructed by augmenting the 2028 ADS resource portfolio with additional resources, by type, such that the final candidate portfolio had the same resource mix as that of **Mid-Case Resource Portfolio**. [5] Customer-side energy supply is captured in the 2028 ADS includes DG/DR/EE/BTM, rooftop solar, and electrical storage modeled on the supply-side is also included in the 2038 generation resource portfolio. New rooftop solar and electrical storage modeled on the supply-side within the **Mid-Case Resource Portfolio** was added the 2038 scenario candidate portfolio. Further, dispatchable DER-EV derived from the NREL Electrification Futures Study (EFS) was also added to the 2038 scenario candidate portfolio. [1] The candidate portfolio was then presented to the production cost model (PCM). The PCM then committed and dispatched resources from the pool of candidates in the simulations.*
4. **Changes in the character and shape of customer demand for electric power**.
   Changes in customer demand were captured exogenously in the Demand-Side Scenarios obtained from NREL and used to derive the 2038 scenario load profiles. The Demand-Side Scenarios created by NREL as part of the Electrifications Future Study (EFS) were derived by a bottoms-up approach based on four customer classes consisting of Residential, Commercial, Industrial, and Transportation. [1] The bottoms-up modeling approach is further discussed in the Assessment Approach of this report.
5. **Changes in utility-scale power supply options**
   *Changes in utility-scale power supply options were captured exogenously in NREL's Regional Energy Deployment System Model (ReEDS) which was used to construct the **Mid-Case Resource Portfolio**, as part of the NREL standard scenarios, used in the WECC 2038 scenarios study. [5]*
6. **Changes in state, provincial, and federal electric system regulations for reliability**
   *Changes in state, provincial, and federal policy are captured exogenously only to the extent that it is captured within NREL's Regional Energy Deployment System Model (ReEDS) which was used to construct the **Mid-Case Resource Portfolio**, as part of the NREL standard scenarios, used in the WECC 2038 scenarios study. [5]*
7. **Evolution of climate change and environmental issues on electric power service**
   State and provincial policies in the west are included in the modeling in the form of RPS, coal retirements, and a CO_2 cost of $55/ton. Other climate change considerations, such as water availability and drought, were studied separately in the WECC 2038 Energy-Water-Climate Change Assessment be studied by a consortium of National Labs (Sandia, PNNL, NREL) on behalf of WECC and will be published in separate report forthcoming.

8. **Evolution of fuel markets in the electric power sector**
   The evolution of fuel markets was not explicitly modeled in this study beyond that of the inclusion of new resource types captured as part of the Mid-Case Resource Portfolio. [5]
9. **Shifts in the cost of capital and financial markets**
   Shifts in capital and financing are captured only to the extent that they are captured in WECC Generation Capital Cost tool which includes all the financing parameters necessary to generate LCOE, LFC, and yearly cash flows. Included in these financing parameters are Capital Investment Costs, WACC, Progress Multipliers, Locational Adjustments, Tax Credits.
10. **Economic growth within the Western Interconnection**
    Economic growth primarily translates to load models directly and generation models indirectly. Economic growth is captured in the scenario studies only to the extent that it is modeled exogenously in the NREL EFS Demand-Side Scenarios [5] selected for the scenario studies. In this regard, the NREL EFS Demand-Side Scenarios consist of nine different load profiles representative of nine different levels of electrification, including load growth, based on customer adoption and technology advancement.
11. **Worldwide developments in the electric power industry**
    Worldwide developments are captured in the scenario studies only to the extent that they are modeled exogenously in the NREL EFS Demand-Side Scenarios and Mid-Case Resource Portfolio [5] selected for the scenario studies. Worldwide developments are captured primarily as technology advancement and climate change. [5]

Distributed Energy Resources (DER)

Recognizing that there are various industry definitions for DER, NERC developed a working definition to create context for discussion. [7] NERC's working definition for DER is:

> *A Distributed Energy Resource (DER) is any resource on the distribution system that produces electricity and is not otherwise included in the formal NERC definition of the Bulk Power System (BPS).*

In recent years, the penetration and role of DER has grown considerably and is transforming the way the BPS is managed and operated. It can be easily argued that we are in the early stages of the DER evolution. The rate of growth in DER is causing planners and researches to scramble to gain a better understanding of how DER is affecting the BPS today, what technology innovations may occur, how it will evolve in the future, how should planners respond, and what policy and market mechanisms may be needed.

Storage Technologies

Storage modeled in this study essentially consist of the following:

- Pumped hydro storage (from the ADS PCM).
- Electrical Storage (from the ADS PCM modeled on the supply-side).
- Electrical Storage (from the ADS PCM modeled as a load adjustment).
- Electrical Storage (from the NREL Mid-Case modeled as a supply-side addition).
- EV Storage (from the NREL Demand-Side Scenarios flexible EV load modeled as a supply-side addition designated as DER-EV).

These storage models are conventual by today's standards but, as the study results suggest, electrical storage will potentially have a much broader impact on the energy future of the BPS as technologies advance and economics improve. Electrical storage is an important topic to be investigated in future studies. While the modeling of storage in the WECC Scenarios is limited, work is already being done by WECC and NREL. As of this writing, WECC is in the process of forming a stakeholder group to investigate the implications of storage on the Western Interconnection. NREL has already started the process of investigating storage including:

- A recent publication (2019) on "Cost Projections for Utility-Scale Battery Storage". [24]
- A Storage Futures Study currently be scoped. [25]

Appendix E – Natural Gas Supplemental Information

The content within this appendix is provided by Jamie Austin. Please note that the forecasts provided within this appendix were posted circa 2019 and 2020 (after the scoping and study of the WECC 2038 Scenarios).

Sensitivities around fuel prices. The study used the NREL Mid Case Natural Gas prices, based on the U.S. Energy Information Administration EIA) Natural Gas (NG) forecast from 2018. The EIA 2020 equivalent NG forecast, published in January 2020, has increased prices in the 20-year time horizon. Ultimately, fuel prices and unit efficiency dictate how resources are committed in the study; Hydro and RPS resources are highest on the stack followed by thermal resources (coal and gas).Sensitivities around resource flexibility, which has the potential of committing more resources that can provide additional dispatch flexibility at evening peak demand periods, should also be studied further as well as methods to assure adequate resource flexibility at evening peak demand, whether from policy, markets, industry, or consumer choice.

Figure 96: Western North American Natural Gas Pipelines [29]

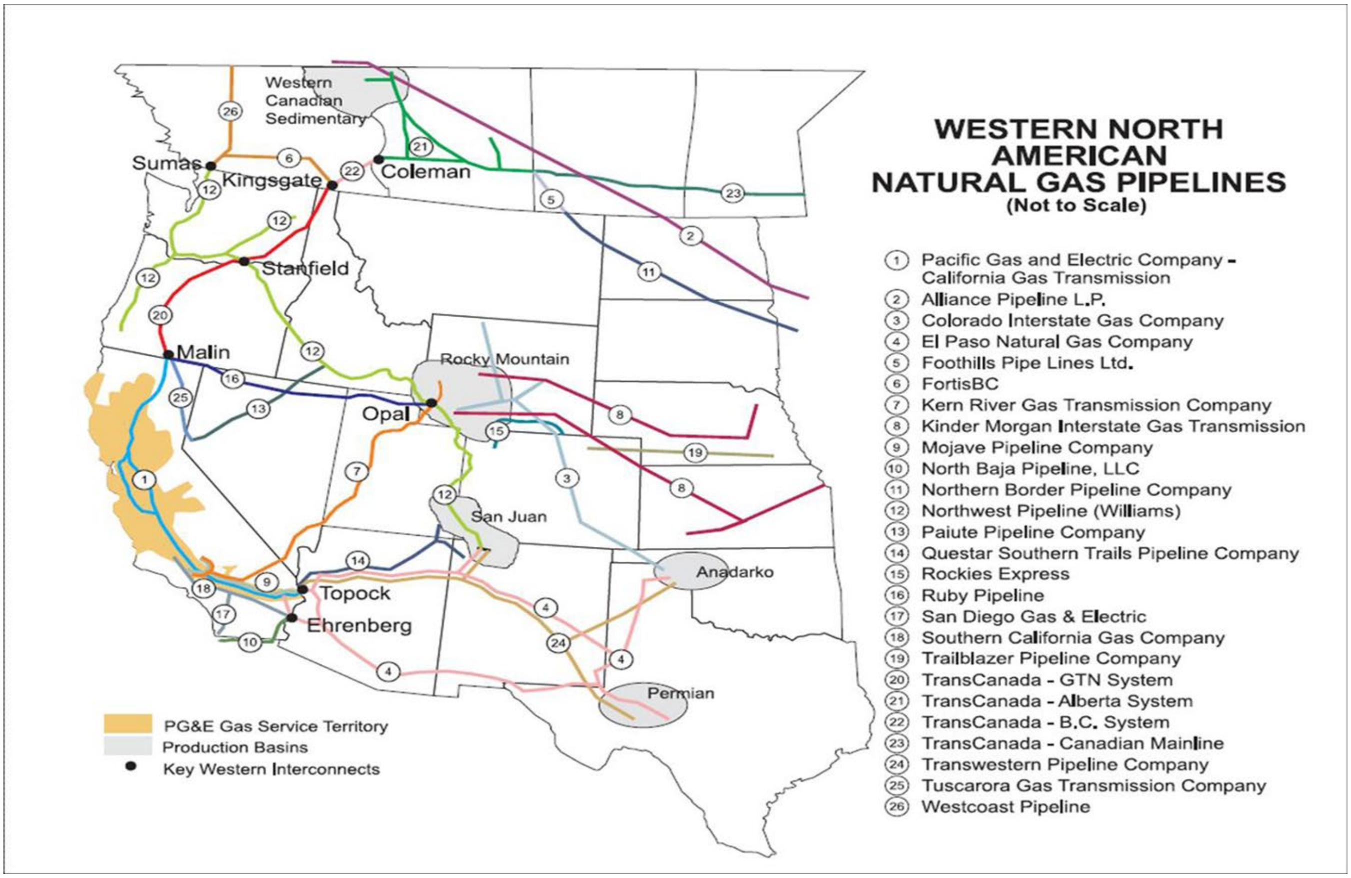
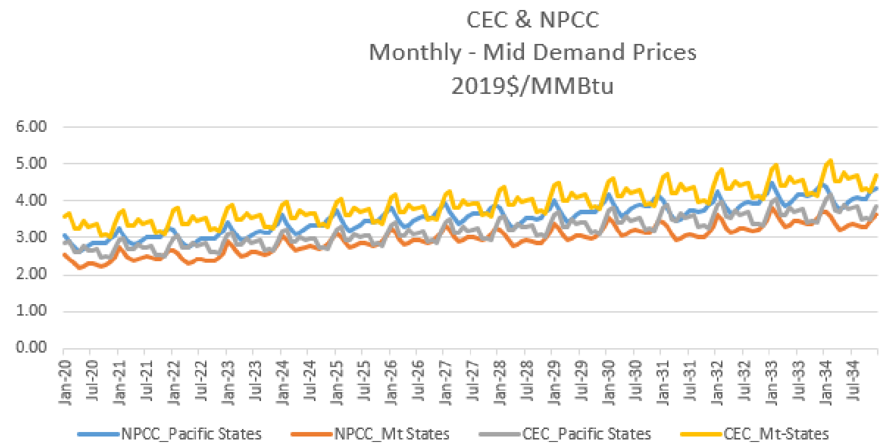


Figure 97: Compilation of Recent Natural Gas Price Forecasts [26], [27], [28]

Forecast Hub Prices

Mid Demand Prices, averaged to EIA - Pacific and Mountain States, regions



Take away

- Consistent projection in all three forecasts for year 2030, at about $4/MMBtu (note, CEC Mt-States forecast is slightly higher)

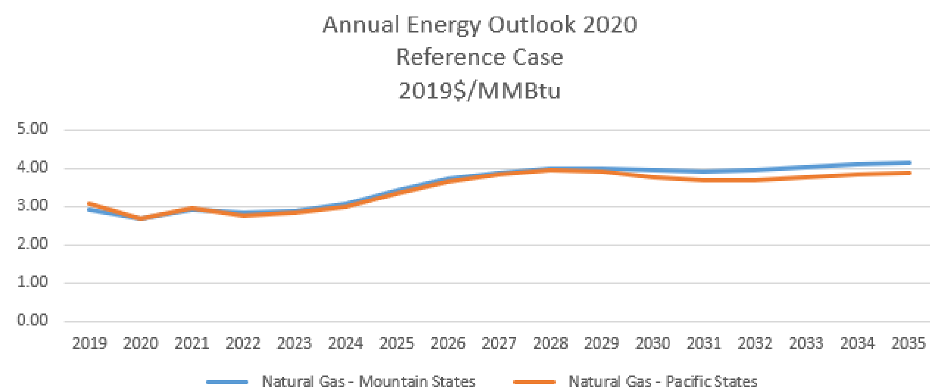
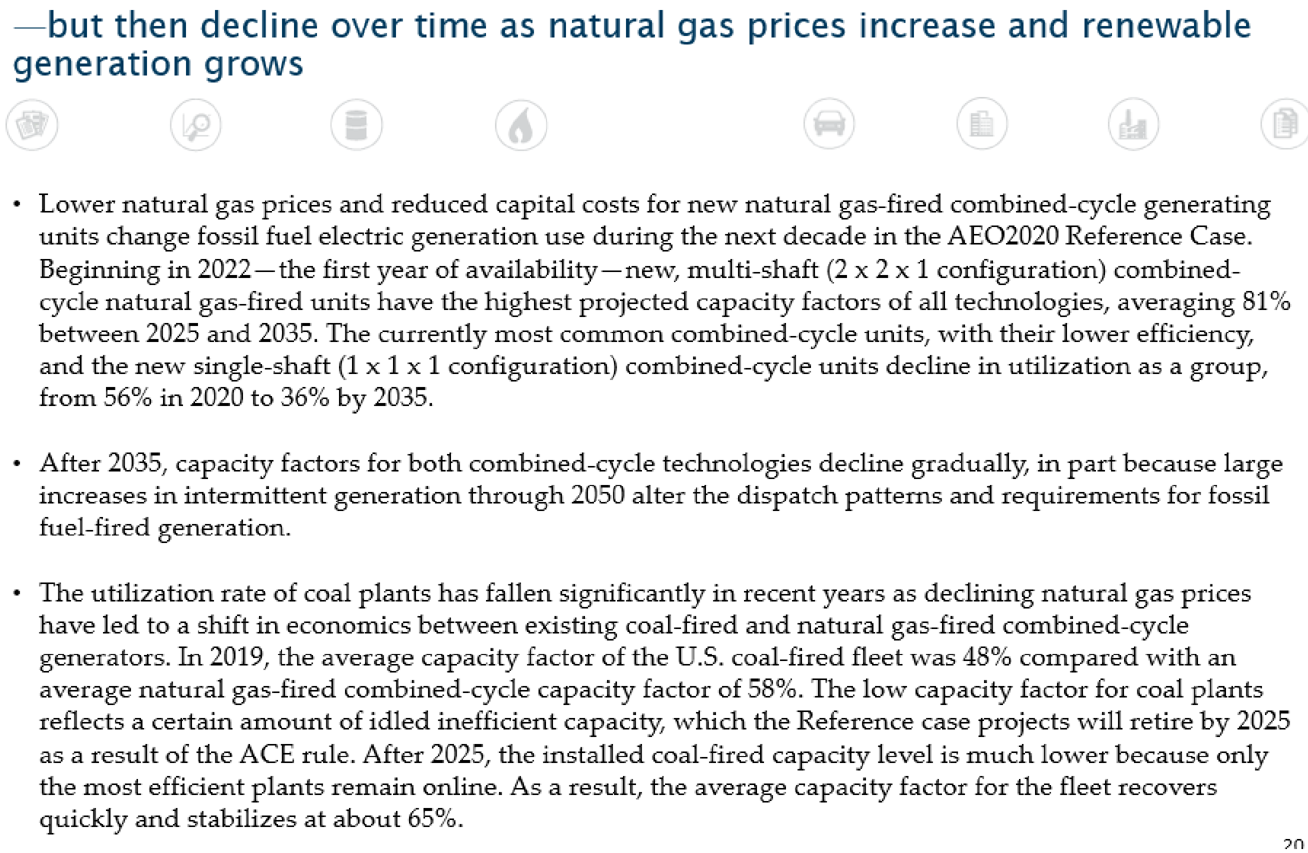


Figure 98: Expected Natural Gas Prices Declines [28]



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