Beginner's Guide to **Understanding Power System Model Results for Long-Term Resource Plans**

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SUMMARY AND PURPOSE

This guide is designed to improve decision-making in the electricity planning process by strengthening dialogue between system planners and relevant stakeholders.

It focuses on interpreting scenario results generated by power system planning models. These results are often used to inform integrated resource plans, which are long-term plans for a utility to meet future electricity requirements. Whether you are a state utility commissioner, commission staff, part of a state energy office, an intervenor in the planning process, or another stakeholder, this guide is designed to help you better weigh in on the modeling methods or interpret the model results to improve decision-making. This guide can enhance your understanding to ask the right questions, which can enable better understanding of results and key assumptions, data, and methods.

A follow-on guide will also be provided, which dives deeper into topics that are becoming more prominent in the electricity planning process but have methods and approaches that are still in development.

INTRODUCTION TO MODELING IN THE ELECTRICITY PLANNING PROCESS

The goal of long-term electricity planning is to ensure there is enough supply to meet demand at all hours in the year (within a certain tolerance), at a reasonable price, and with a portfolio of resources that meets local, state, and federal policy requirements. Utilities need to proactively plan for and procure resources because it can take several years to develop and build a new power plant. Most power plant developers will not build new projects until they know the electricity will be purchased. Utilities typically rely on power system planning models to identify a portfolio of assets that meet all system and customer requirements. There is no one "right" portfolio because there are trade-offs among requirements, but proper modeling provides an accurate picture of the trade-offs.

Inadequate modeling can lead to a proposed portfolio with reduced system reliability, higher costs, or poor sustainability, relative to other portfolio options. For example, improper modeling might lead to an electricity system that is "overbuilt," meaning the utility has more resources than needed. A system like this is reliable but also more expensive than an alternative system. Similarly, a model might not be able to identify a portfolio of resources that could provide the same level of sustainability at a lower cost due to improper assumptions or insufficient methods. Or, a model might result in a system that is incapable of serving all the electricity needs, leading to outages or poor sustainability that could have otherwise been prevented. Any combination of these modeling mishaps can occur, which is why it is important to ensure it is done correctly.

With a better understanding of the modeling process, you can identify potential shortcomings, understand the risks of a given portfolio, and gain more confidence in decisions backed by model results. The following sections describe electricity models and their assumptions, methods, and outputs.

OVERVIEW OF ELECTRICITY MODELS

A long-term resource plan based on power system model results typically proposes an electricity *supply* mix. The following explanations of common terms used in power system modeling will help you understand the model's proposed solutions:

- **Demand.** Future electricity *demand* is typically assumed in the electricity planning process, and it is often represented as an hourly profile. The sum of electricity demand across all hours of the year is the *annual demand*, and it corresponds to the amount of electricity generation that is needed to meet all end-use services that are met by electricity. The hour with the highest level of demand defines the *peak demand* of the system, which typically corresponds to the timing of the greatest need for space heating or cooling.
- **Capacity.** The total amount of installed *capacity* is often based on the peak demand, and it is typically expressed in megawatts (MW) or gigawatts (GW). For example, if a system expects 1,000 MW of demand during the hottest summer afternoon or the coldest winter evening, then it would need at least 1,000 MW of available resources to serve that demand. And because no capacity is perfectly reliable, the utility would want to have more than 1,000 MW available in case something happens to a key power plant or transmission line. Some systems incorporate variable resources like wind and solar, which means the availability of the resource can change depending on weather conditions and the time of day or year. For these systems, the availability of the capacity is a primary metric to ensure the lights stay on during fluctuations in generation. (This is covered in more detail in the "Advanced Topics for Evaluating Model Results in Long-Term Resource Plans" [Cole et al. Forthcoming], referred to as the "Advanced Topics guide" from here on.)
- **Generation.** The total amount of electricity *generation* is based on overall demand across the year and is typically expressed in megawatt-hours (MWh). So, a 100-MW power plant that is producing at full capacity for 4 hours would produce 400 MWh of generation. And a 100-MW power plant that is producing at full capacity for 25% of the year would produce 100 MW × 0.25 × 8,760 hours per year = 219,000 MWh over the course of a year.

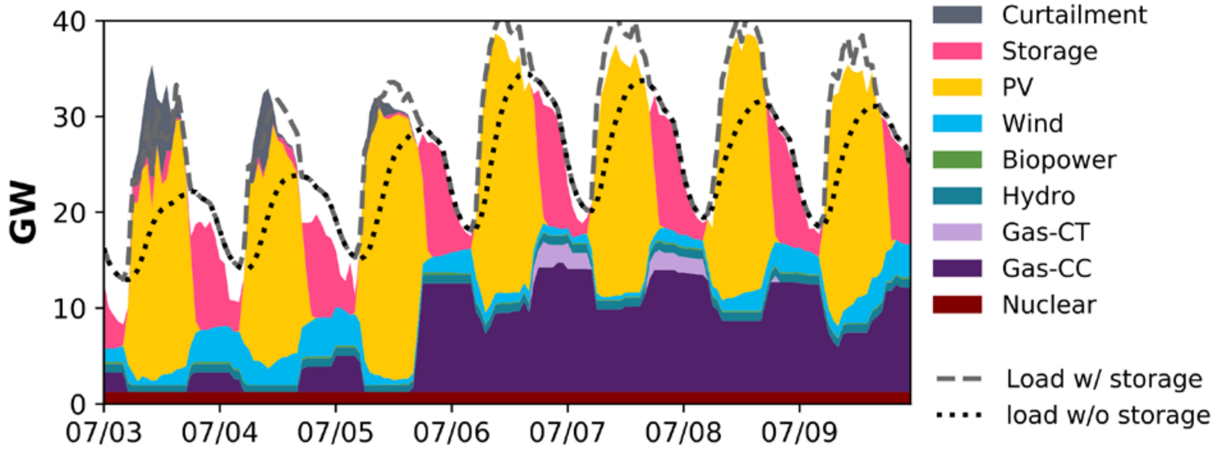

Figure 1. System operation during a simulated stress period for the New York electricity system using a simulated grid mix for seven days in July. PV = photovoltaics, Gas-CT = natural gas combustion turbine, and Gas-CC = natural gas combined cycle.
Source: Cole et al. (2020).

These concepts are demonstrated in **Figure 1**, which shows the simulated operation of an electricity system in New York that uses a large amount of renewable resources. This is the kind of figure that might be included in an integrated resource plan to demonstrate how a proposed generation fleet would be expected to operate. In this example, the peak demand (or maximum load) is about 35 GW and occurs on July 6, so more than 35 GW of capacity is needed to reliably meet demand. Storage charging, which is the diversion of electricity to storage devices like batteries instead of to end-use consumers, can increase the demand but then makes electricity available during other periods when variable resources are not producing. For example, solar photovoltaics (PV) generate electricity during daytime hours only, and the total generation fluctuates based on the solar resource. That reduced generation at night is balanced out with storage and electricity from natural gas generators. Conversely, nuclear generates at a constant level throughout the weeklong period.

Models are built around these aspects of electricity supply and demand and take a variety of forms. Some models are spreadsheet calculation tools, where users make manual adjustments to find a portfolio that meets the required criteria (e.g., reliability, affordability, and sustainability). Other models are optimization or simulation-based tools that use mathematical algorithms to identify solutions.

Because of the complexities of the energy system, it is common for more than one model to be used to answer questions about elements of a long-term electricity system plan. For example, one model might be used to represent hydropower resources so that river flow constraints and conditions are appropriately captured, and a separate model might be used to select the least-cost portfolio for meeting future electricity needs. Knowing why different models are used and how results from one model impact another can help you understand whether the overall process results in a meaningful and robust solution.

Model results are concrete, taking the form of a specific portfolio or a least-cost resource option—but remember that models are tools for decision-making. Models typically give specific and definite solutions, but that does not mean those predictions are correct. In fact, the future will almost certainly be different than predicted. There is an element of uncertainty in model predictions, even if the output is presented as a single solution. There is also subjectivity imposed by planners to determine what is feasible or how to rank priorities. For example, consider the question of when a new technology such as small modular reactors might be available. A vendor might recommend one date to use in the model while a technology consultant provides another. As another example, one planner might prioritize using a hydropower unit to serve peak demand while another planner minimizes use of the hydropower unit during certain times of the year to maximize fish survival rates.

It is easy to get caught up in model results or methods and forget that the ultimate purpose is to inform a decision. As long as model outputs can improve decision-making quality, the model has fulfilled its purpose. Models and model results need to be good enough to support decision-making, but they should never be expected to be perfect.

DEVELOPING QUESTIONS TO ASK UTILITIES

There are three main categories of a long-term electricity system plan: assumptions, methods, and outputs. In this section, we provide an introduction and context for each category, give examples from published utility documents, and list questions that might warrant critical consideration and engagement with others in the planning process. You can bring these questions to planning discussions with a utility to better understand model results and move toward a decision with stakeholders. Though questions from this document can be asked verbatim, they can also be tailored as needed to help meet specific goals for engaging with the utility.

Assumptions and Data

Assumptions and data are the foundation on which models are built, and they are central drivers of model outcomes. Proposed utility portfolios are always forward-looking, which means they are rooted in the assumptions and data that reflect the utility's best understanding of the future. However, low-quality assumptions or data can lead to low-quality results. Assumptions and data should be up to date and can include ranges because of the uncertainty associated with forward-looking projections. These ranges will often be captured via scenarios, which are different model runs or projections that correspond to different assumptions or conditions (e.g., high load growth versus no load growth). The types of data and assumptions vary across models, but the following questions are generally ordered based on the impact that certain assumptions or data have on driving model solutions.

Questions

1. What are the assumptions about load growth?

Load growth is typically what drives the need for a utility to procure new resources (along with the retirement of existing generators). While the U.S. power system experienced rapid and sustained growth in the latter half of the 20th century, the nationwide demand for electricity has been relatively flat over the past 20 years (see **Figure 2**). This lack of load growth is typically attributed to increasing energy efficiency and structural changes to the economy, and it reflects the fact that some energy-intensive end uses (such as space heating and water heating) are currently met with direct fuel use instead of electricity. However, the trends in load growth are forecast to change as energy-intensive end uses are increasingly powered by electricity.

Many projections suggest that electricity demand will grow across all parts of the country. The federal Inflation Reduction Act passed in 2022 introduced or expanded many incentives that will encourage the electrification of vehicles and heating. State and local policies can have similar effects in shaping load growth. Economic development and population growth can also lead to higher load growth, and the addition of a single large customer (e.g., data center or a new industrial facility) can require substantial new resource investments in a utility territory. Failing to account for potential sources of increased electricity demand can underestimate load growth and, in turn, result in a plan with insufficient resources to serve loads. On the other hand, overestimating load growth can lead to an overbuilt system and unnecessary or stranded assets.

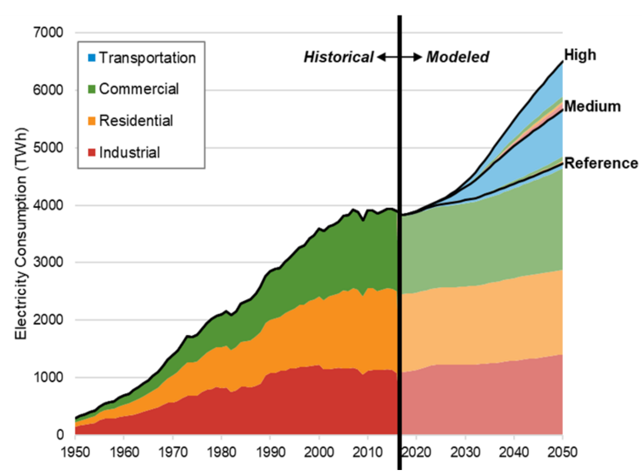

Figure 2. National demand for electricity from various sectors, with three projections for future load growth based on expectations for electrification of end uses such as transportation and heating.
Source: Mai et al. (2018)

Figure 3 shows an example of projections for a given region (New York in this case). The chart compares how historical data and trends relate to the load projections and provides three different levels of potential load growth to help capture uncertainty. Although not shown here, the same document includes projections for summer and winter peak demand to help inform the planning of both capacity and energy needs. The load projections are built from assumptions of energy efficiency adoption, electric vehicle adoption and usage, space heating electrification, building codes and appliance standards, and other factors that can affect when and how much electricity might be consumed.

> *Additional questions to consider:* What underlying elements are considered in the load projections, such as the percentage of vehicles that might be electric, the rate of heat pump deployment, the creation of industrial development zones, large customer carbon-free commitments, or the pace of energy efficiency adoption?

2. What technology cost and performance assumptions are being used?

Because power system models typically trade off the cost and value of resources as they select different resources, the cost and performance assumptions are important drivers of a model solution. And because the cost and performance of many technologies can change rapidly,[1] it is important these assumptions are up to date and reflect a plausible view of the future.

> *Additional questions to consider:* Where do the cost and performance assumptions come from (including the source and date)? What evidence has been provided to show the assumptions are reasonable? For example, costs might be compared against public sources,[2] or they might be compared to internal sources such as recent bids from proposals or recent electricity purchases. Costs can also be compared against those from other nearby utilities.

1 Wind, solar photovoltaics, and battery storage all experienced significant cost declines from 2010 to 2020. And all technologies experienced near-term cost increases from inflation and supply chain disruptions over the course of 2022 and into 2023.

2 Examples include the Annual Technology Baseline (https://atb.nrel.gov/), the Annual Energy Outlook (https://www.eia.gov/outlooks/aeo/data/browser/#/?id=123-AEO2023&cases=ref2023&sourcekey=0), and the Lazard Levelized Cost of Energy reports (https://www.lazard.com/research-insights/levelized-cost-of-energyplus/).

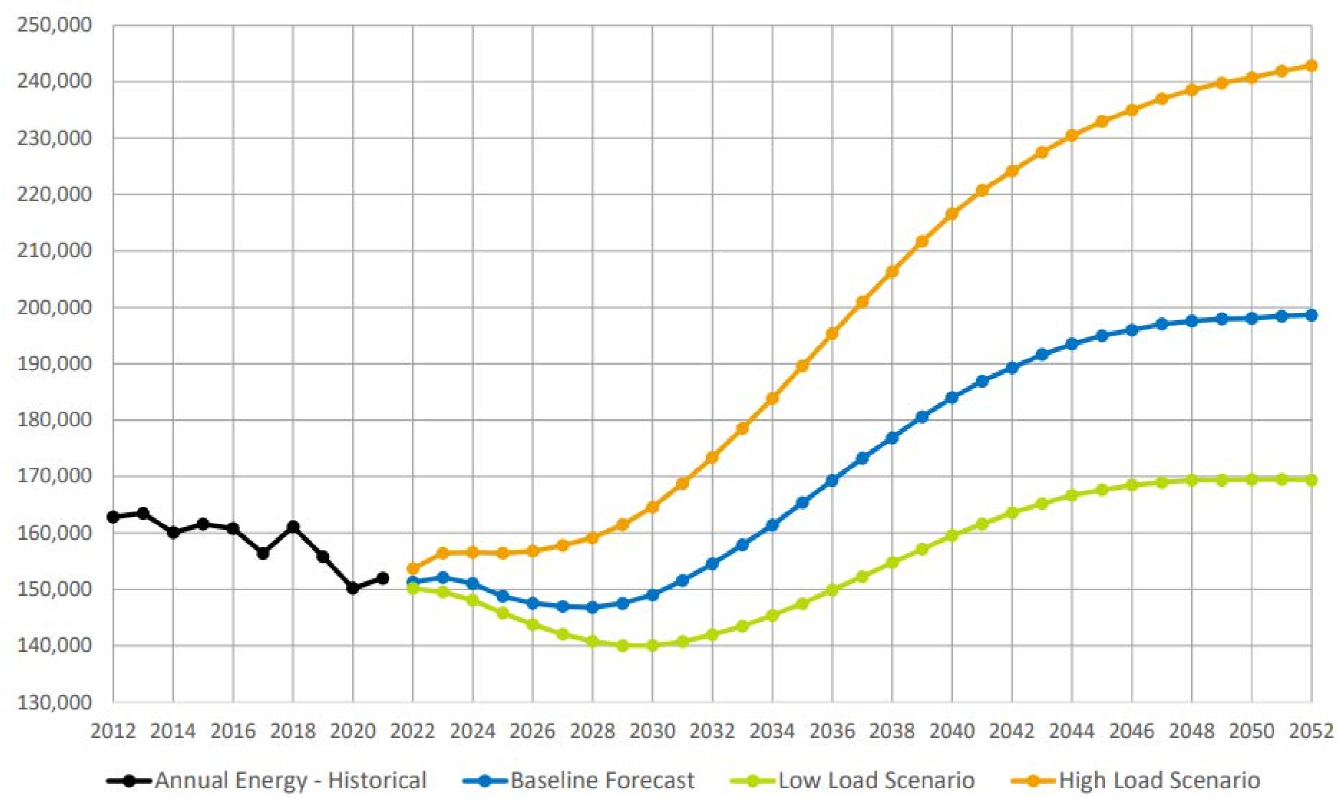

Figure 3. Load projections for the New York Independent System Operator. The load projections include three scenarios—low, baseline, and high—which are shown relative to the historical values.
Source: New York ISO (2022)

Figure 4 shows an example of cost inputs used for a planning study. The performance-related inputs to consider (not shown in the figure) include power plant heat rates (which are a measure of their efficiency in converting fuel to electricity), storage round-trip efficiency, and power plant or transmission losses, among others.

3. What are the assumptions about fuel prices?

Fuel prices not only drive the competitiveness of resources that rely on fuels, but also the regional price of electricity. In nearly all U.S. markets, the price of electricity tracks the fuel price of the last power plant that was dispatched to meet demand, which is often a natural gas plant. In recent decades, the natural gas price trends have varied widely, including periods of sustained low prices and substantial price spikes. These dramatic fluctuations are helpful context for evaluating the reasonableness of assumed future natural gas prices, both in terms of absolute price and uncertainty analysis. However, different fuels exhibit different levels of volatility, and the future price of many fuels depends on a variety of factors, including policy, supply chains, and geopolitical events. **Figure 5** provides an example of fuel price inputs from the 2023 Dominion Energy South Carolina integrated resource plan.

> *Additional questions to consider:* What is the source of the fuel price assumptions? What evidence has been presented to provide confidence in the projections?

4. Which policies are being represented?

There are a variety of local, state, and federal policies that can drive planning outcomes. At the federal level, tax credits, such as those from the Inflation Reduction Act, for electricity supply technologies influence the relative cost-competitiveness of different technology options (see **Figure 6**). Federal tax credits for end-use technologies and strategies (such as electric vehicles, electric heat pumps, and efficiency measures), equipment or manufacturing efficiency standards or incentives, and building codes influence the amount and timing of electricity demand.

Relevant state-level policies put limits or requirements on the portfolio of technologies that can be proposed,[3] typically through clean energy or renewable portfolio standards, deployment mandates, and bans or conditions on the deployment of certain technologies, such as new nuclear.[4] State-level emissions targets can also have implications for power sector planning when they require a certain level of deployment of end-use technologies or the decarbonization of end-use sectors, which is often most efficiently achieved through electrification.

Finally, building code adoption and new construction requirements can influence the magnitude and makeup of energy demand in

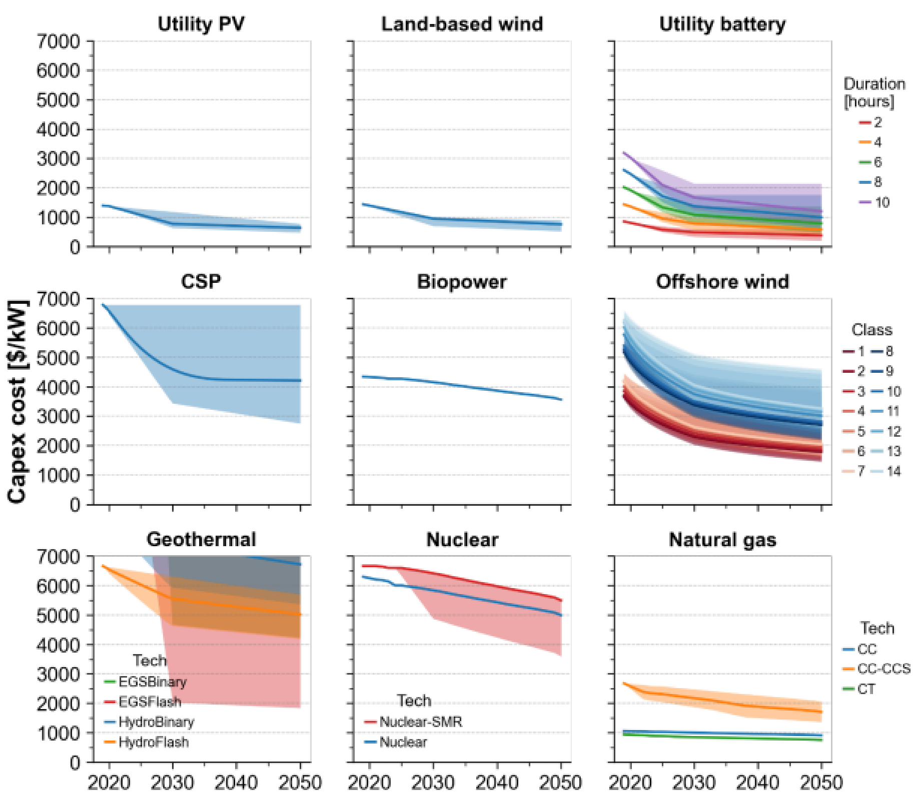

Figure 4. Capital cost inputs (also called capital expenditures, or "Capex") for various sources of electricity, including utility-scale solar PV, land-based wind, utility-scale battery energy storage, concentrating solar power (CSP), biopower, offshore wind, geothermal, nuclear, and natural gas under moderate (center line), advanced (shaded area above the line), and conservative (shaded area below the line) cost assumptions.
Source: Denholm et al. (2022)

3 See Barbose (2023) for a summary.

4 For example, see National Conference of State Legislatures (2023).

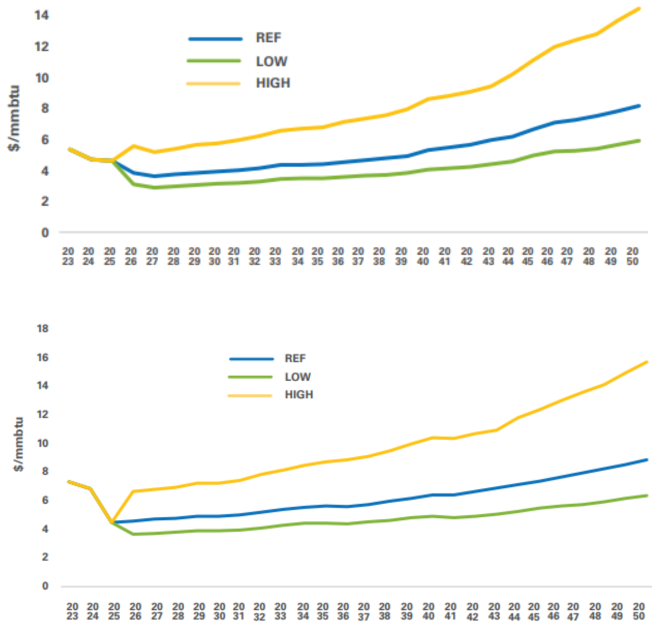

Figure 5. Fuel prices from the Dominion Energy South Carolina 2023 Integrated Resource Plan (the upper figure is natural gas, and the lower figure is coal). The prices include low, reference, and high assumptions to capture a range of potential prices.

Source: Dominion Energy (2023)

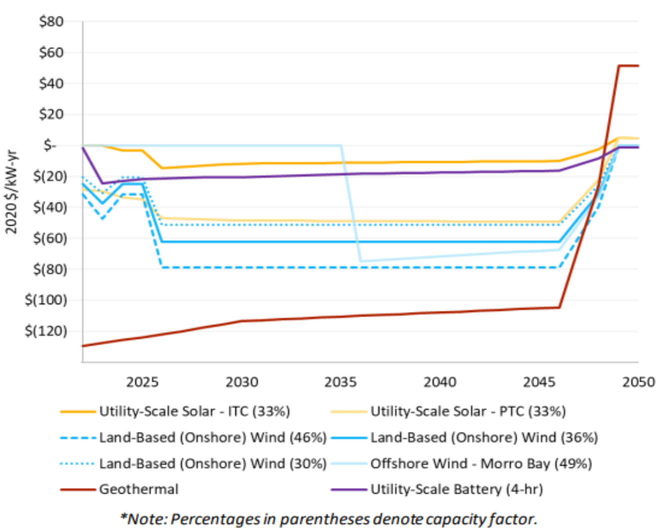

Figure 6. Changes in the total levelized fixed cost (an all-in cost metric) of electricity resources due to the Inflation Reduction Act for plants in California. Costs below $0 indicate a cost reduction due to the Inflation Reduction Act. Increases in later years are due to the assumed phase-out of tax credits.

Source: California Public Utilities Commission (2022)

buildings, and local siting ordinances can influence the deployment potential of certain technologies, especially solar and wind.

Given the wide array of policies that directly and indirectly influence a utility's plan for resource investment, it is valuable to clarify which policies were considered in the proposed plan, and why others were not considered.

> *Additional questions to consider:* How are the policies represented in the model? For example, if a technology is eligible for more than one tax credit, how does the model choose which tax credit to take? Or, if a state or utility has a carbon reduction target for 2040, how are interim targets specified in the model (e.g., the year the model requires the scenario to be halfway to the target)? Are there policies that are not represented? If so, what might there impact be if they could be incorporated?

5. What are the assumptions about existing resources?

Electricity generation resources and procurement contracts have finite lifetimes. Some or even many of existing resources will likely reach the end of their lifetime during the planning horizon (see **Figure 7** for an example from the PacifiCorp 2023 integrated resource plan). For example, nuclear power plant operation depends on licensing by the Nuclear Regulatory Commission, with current licenses allowing for 40 to 80 years of plant operations in the United States.

> *Additional questions to consider:* How does the model treat resources that may reach the end of their lifetime? Does it assume they will be retired, or is there a lifetime extension or contract renewal? Will the resources be used differently in the future, such as being ramped more frequently or used more sparingly? Is the capacity factor of existing resources a fixed assumption, or a model output?

6. What are the assumptions about transmission cost and availability?

Electricity can be generated far from where it is consumed, and transmission delivers it to where it is needed. Interconnecting a new generation resource typically requires a transmission study,[5] which can be a complex and time-consuming process. Building new transmission projects in the United States can also be very challenging because they are often subject to delays, resulting in significant uncertainty in the associated costs.

5 See Simonson et al. (2021) for an example transmission study.

Coal Fired Plants

Plant	PacifiCorp Percentage Share(%)	State	Assumed End of Life Year	Nameplate Capacity (MW)
Colstrip 3	10	Montana	2025*	74
Colstrip 4	10*	Montana	2029	74
Craig I	19	Colorado	2025	82
Craig 2	19	Colorado	2028	79
Dave Johnston I	100	Wyoming	2028	99
Dave Johnston 2	100	Wyoming	2028	106
Dave Johnston 3	100	Wyoming	2027	220
Dave Johnston 4	100	Wyoming	2039	330
Hayden I	24	Colorado	2028	44
Hayden 2	13	Colorado	2027	33
Hunter I	94	Utah	2031	418
Hunter 2	60	Utah	2032	269
Hunter 3	100	Utah	2032	471
Huntington I	100	Utah	2032	459
Huntington 2	100	Utah	2032	450
Jim Bridger 1 GC 24	67	Wyoming	2037	354

Figure 7. End-of-life assumptions for coal-fired power plants from the 2023 PacifiCorp Integrated Resource Plan. Only a portion of the table is reproduced here.
Source: PacifiCorp (2023)

> *Additional questions to consider:* How far away are the generation resources considered in the analysis? How has the analysis accounted for the transmission of resources? How do assumptions about procuring new transmission compare to what has happened historically? You can get more specific and ask whether expanding transmission to a market hub is considered or if the cost to deliver power from a remote renewable energy site is included.

Figure 8 shows an example of a long-distance transmission option that can be used to import power from a neighboring region. This view of imports provides a different perspective on meeting electricity needs for the service territory rather than having all generation served by units within the service territory.

7. What are the assumptions about distributed energy resources and demand-side management?

Distributed energy resources (DERs) include resources such as customer-sited solar panels and behind-the-meter batteries. These resources are often not owned or controlled by the utility, but they impact the quantity and timing of electricity the utility needs to deliver. Customer-sited solar is prevalent in certain parts of the country, but its adoption is highly dependent on customer decision-making and compensation mechanisms. Behind-the-meter batteries are becoming more popular in buildings with occupants who place a high value on avoiding power outages or who want to minimize reliance on grid electricity.

Demand-side management programs are designed to incentivize customers to reduce their electricity use when the price of electricity is high or when electricity supply is tight.

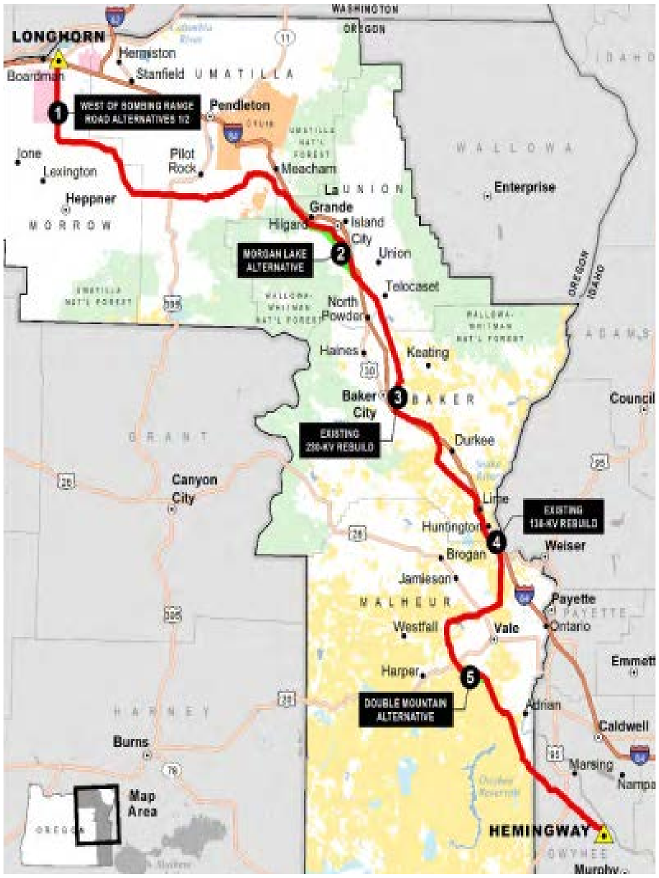

Figure 8. Transmission option to link the Idaho Power service territory to the mid-Columbia trading region from the Idaho Power 2021 Integrated Resource Plan.

Source: Idaho Power (2021)

Some programs are designed for a specific end use, such as air conditioning or electric vehicle charging, whereas other programs can apply to overall electricity use, such as time-of-use rates that specify electricity prices for specific times of the day or year. Some programs compensate customers for simply enrolling in the program, whereas others compensate customers for each event where the customer is called upon to manage their load in response to a utility signal. In some planning exercises, the DERs are embedded within the load growth assumptions, so be aware that DER assumptions might be intermingled with other assumptions. **Figure 9** provides one example of how energy efficiency resources were included in an integrated resource plan.

There are many more electricity consumers and devices than large power plants. This makes demand-side programs often more challenging to represent in models than traditional supply-side resources like new power plants. The programs are also more prevalent in certain utility service territories, so it's important to consider if capturing these resources is important to inform planning decisions.

Additional questions to consider: Which DERs were represented? Is the model allowed to select DERs or energy efficiency as resource options? How were the DER assumptions developed? How do they compare to what has happened historically? How large are the DERs in the context of the system? For example, 1 MW of DER growth in a 10,000-MW system is such a small

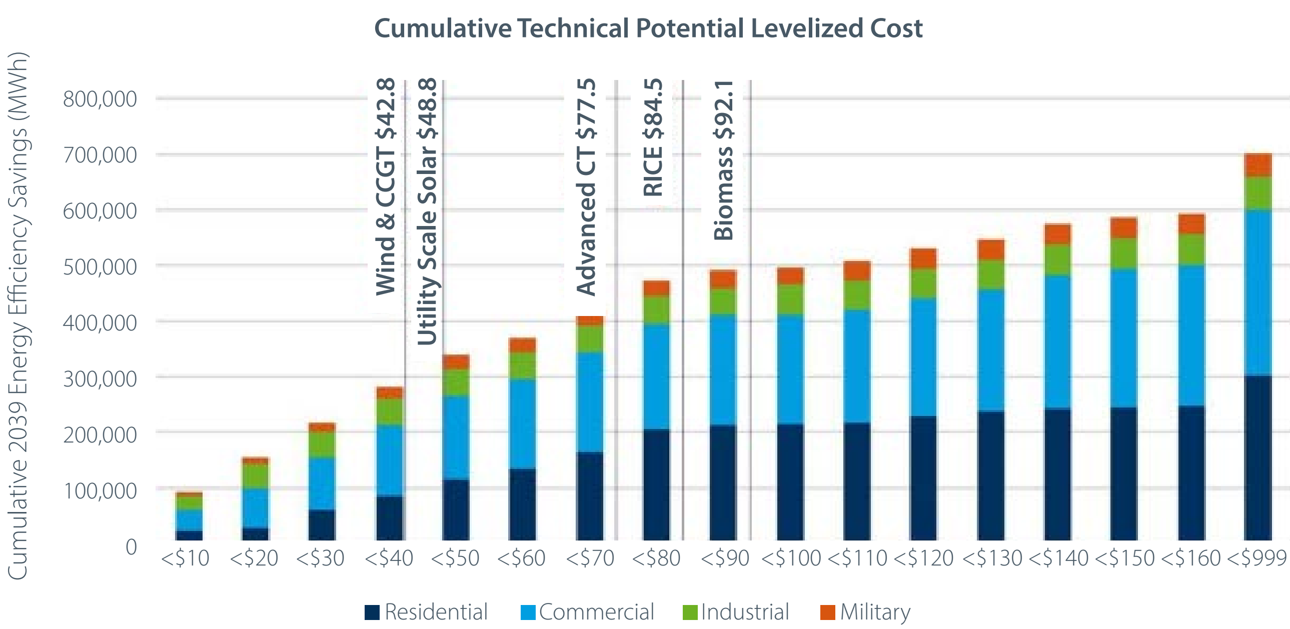

Figure 9. Cost of energy efficiency investments (x-axis, in $/MWh) that produce a given amount of energy efficiency savings (y-axis) for the Colorado Springs Utility 2020 Integrated Resource Plan. Costs of generation resources are shown for reference. CT = combustion turbine, CCGT = combined cycle CT, RICE = reciprocating internal combustion engine.

Source: Colorado Springs Utilities (2020) fraction, it's more important to understand magnitude than how it is represented. Is it really only 1 MW? Is it being underestimated? Finally, are there important DER programs that the utility has not considered?

8. What financing assumptions are being used?

Financing assumptions can have dramatic impacts on resource selection by models. This happens because financing assumptions drive the trade-off between today's capital costs of building a resource and the future costs of operating the resource. For example, some resources (such as building a new wind or PV plant) have higher up-front costs that require financing, but have very little ongoing costs, while other resources (such as operating a natural gas plant or signing a power purchase agreement) have lower or even zero up-front costs, but higher ongoing costs. Financing assumptions can be complicated to understand, but some simple questions might be useful in understanding the assumptions. **Figure 10** provides an example of the kinds of financing numbers that might be used as inputs for an integrated resource plan.

> *Additional questions to consider:* What is the financing model used in selecting the portfolio? How does that compare with actual financing practice in place right now? How might results change if there were a different assumption about the financing model? How do the financing assumptions influence model decision-making?

9. Which electricity supply technologies does the model consider?

The U.S. power sector has historically relied predominately on just a few generation resources. Hydropower and fossil-fuel-fired thermal generation dominated the early U.S. grid until the emergence of nuclear power and large-scale energy storage projects (e.g., pumped storage hydropower) in the 1970s (see **Figure 11**, which shows the amount and type of capacity added to the grid each year since 1950). Natural-gas-fired generation capacity grew rapidly in the early 2000s, followed by the emergence of wind (primarily land-based), solar (mostly photovoltaics), and battery storage technologies (especially lithium-ion batteries) more recently. Some technologies play a bigger role in select regions—such as geothermal electricity in California and hydropower in the Pacific Northwest—but their potential for future growth depends on resource potential that is more geographically limited and influenced by siting and permitting processes. Even more technologies could be on the horizon—such as small modular nuclear reactors, flow batteries, and hydrogen—but it is unknown when they will be technically and commercially viable at scale.

Given the complex history and rapid evolution of the energy landscape in recent decades, it can be challenging to determine the right set of resources to consider in a modeled portfolio. Representing new types of resources in models can also be challenging, so there are trade-offs between the level of work required to represent the technology and the value of having it represented. The key element is that those trade-offs are evaluated and that the scope of technologies is sufficient to answer the questions posed by the planning problem.

Other potential resources can be considered, but they may not be ready for deployment. For example, hydrogen technologies are a potential resource for providing low-carbon energy, but the supply chain for hydrogen-driven

	Capital Mix	Cost of Capital	WACC	Discount Rate
Debt	50.78%	4.75%	2.412%	1.812%
Preferred Equity	1.68%	5.37%	0.090%	0.090%
Common Equity	47.54%	9.99%	4.749%	4.749%
TOTAL	**100.00%**		**7.252%**	**6.652%**

	ACTUAL	EFFECTIVE
State Tax	4.90%	4.90%
Federal Tax	21.00%	19.97%
Effective Tax Rate		**24.87%**

Figure 10. Summary of financing assumptions from the AES Indiana 2022 Integrated Resource Plan. WACC is weighted average cost of capital.
Source: AES Indiana (2022)

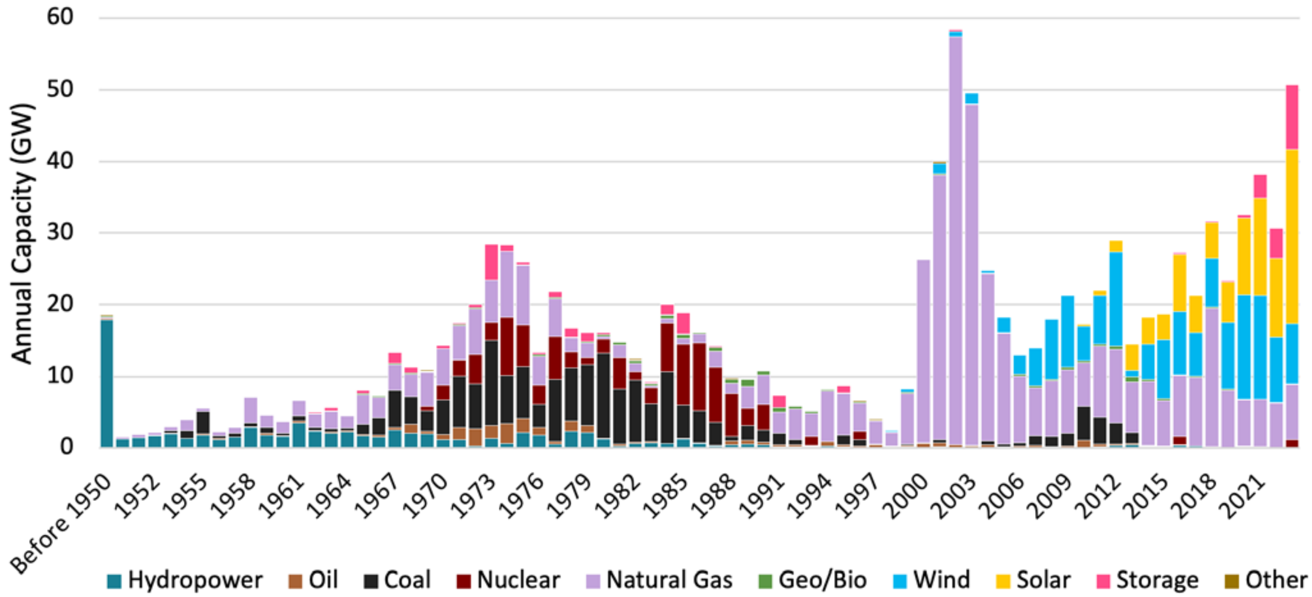

Figure 11. Annual capacity additions in the U.S. from 1950 through 2023. Values are based on the U.S. Energy Information Administration's Form 860M for August 2023, and 2023 additions include units planned to come online in 2023 that have started construction but were not yet online in August.

electricity will take some time to develop. If a model assumes that hydrogen technologies will be available sooner than is realistic, the model could have poor outcomes. The opposite can also happen: For example, a technology may be excluded from the model because it is not commercially available today, but it could play an important role for a portion of the planning horizon. Weighing the risks and potential benefits of a new technology is one of several important trade-offs to consider with power system planning.

> *Additional questions to consider:* Are there some resources that are not considered but should be? Has the utility provided enough information for why they have not been considered? Are we confident that all the considered technologies are ready to be deployed?

10. What uncertainties are represented?

Models will take different approaches for capturing uncertainty, and the number of potential uncertainties is enormous. The crucial element is to ensure that the uncertainties most relevant to decision-making are captured. Or, if an element of uncertainty is not captured, does it limit the ability to use the results to inform decision-making? For example, if there is potential for large load growth in a region due to new large industrial customers and the potential for rapid electric vehicle adoption, but the utility only uses a single load projection in planning, how sure is it that the plan will be robust if there is more rapid load growth than expected?

It is important to capture the proper uncertainties—those that change or inform decision-making—to apply the results from the model. Failing to capture important uncertainties in the decision-making process could lead to situations where a utility starts pursuing a portfolio only to find that the portfolio will now be very expensive or will not meet reliability targets. A key aspect of the planning process is to think through what factors are not modeled and to understand what might happen if they were represented. For example, if a model captures only the utility's service territory, what might happen if neighboring regions build out a lot of wind or solar resources or retire large generators? How might that impact conditions for importing or exporting power to meet utility needs? The way uncertainties are captured in models vary considerably and should reflect where planners think there is the most important uncertainty.

> *Additional questions to consider:* Why were certain uncertainties selected and others omitted? Why was relative weight put on one set of uncertainties versus another? You might also consider how uncertainties impact the final portfolio selection outcome. In some cases, uncertainties are simply there to help decision makers understand other futures, but do not have bearing on the final resource selection, whereas in other

cases the uncertainties influence the final resource selection. **Figure 12** provides an example of one utility's approach to representing a subset of uncertainties.

Key Model Outputs

Model outputs are the primary information used to inform decision-making and long-term electricity system plans. Models can have thousands or even millions of outputs, but typically a small subset of outputs provide the most important information. The questions in this section focus on some of the key outputs that you should understand to determine if a model is performing well in the planning process.

Questions

1. **What resources are being proposed to be built and/or retired?**

Resource procurement decisions are primarily based on which resources a model decides to retire or build. When you are evaluating this output, there are some important nuances to consider. Simulated power plant retirements can be predefined (i.e., the user defines when and how much capacity should be retired), or they can be part of the model solution (i.e., the model is given the *choice* to retire generators that cannot achieve sufficient revenues). A power plant can also appear as a retirement if it is undergoing a retrofit to enable fuel switching, like a coal-to-gas retrofit that might appear as a coal retirement, followed by a natural gas addition. Finally, new capacity can appear in a given year, signaling the beginning of commercial operation; a complete understanding requires more information about the assumed construction timelines, which can vary dramatically based on the resource type.

Figure 13 shows an example from the Public Service Company of New Mexico 2020–2040 integrated resource plan. Capacity additions and retirements can be implied from the net difference in the 2021 and 2040 values. More than one 2040 portfolio is shown, representing different requirements for a future resource mix. This long-term view of portfolios is often the driving factor of resource procurement decisions.

This is an important time to remember that models are tools for making decisions. Model outputs for what is built or retired do not prescribe a specific decision that should be made. Instead, they provide valuable information and analysis to help people make informed decisions.

Additional questions to consider: Why is the model choosing the resources shown? Why are certain power plants getting retired?

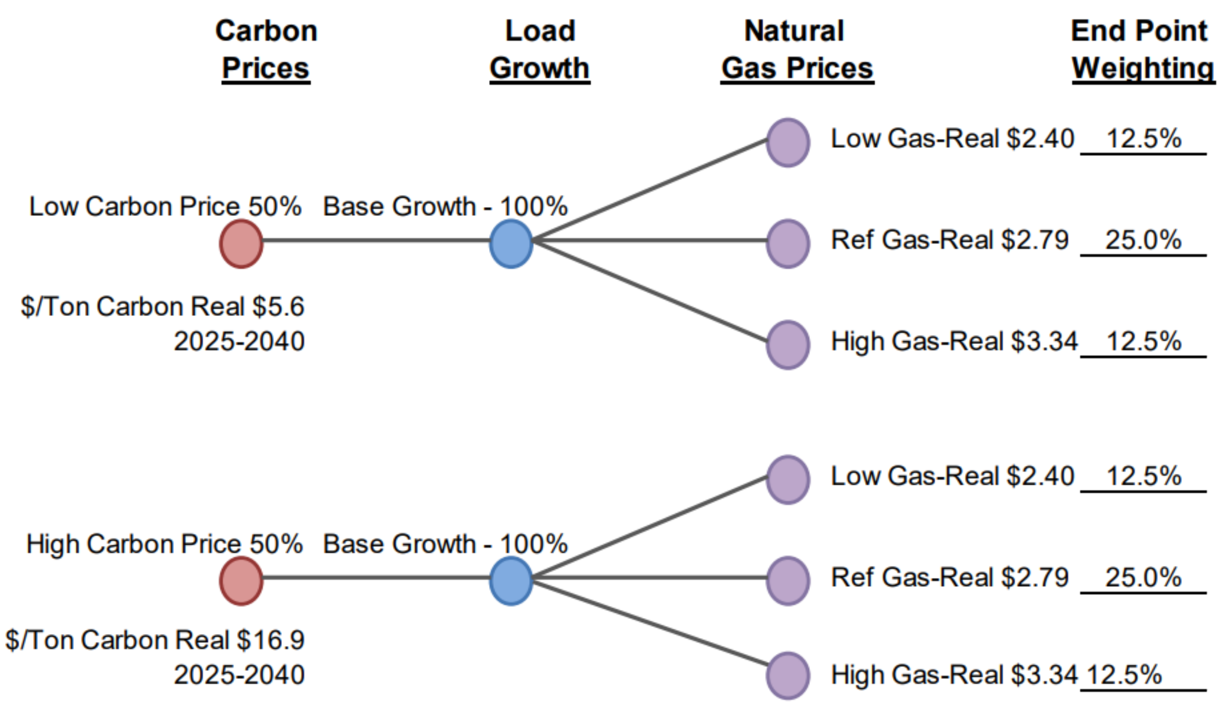

Figure 12. One approach (a scenario tree) for representing some uncertainties in a long-term planning process, taken from the Ameren Missouri 2022 integrated resource plan.
Source: Ameren Missouri (2022)

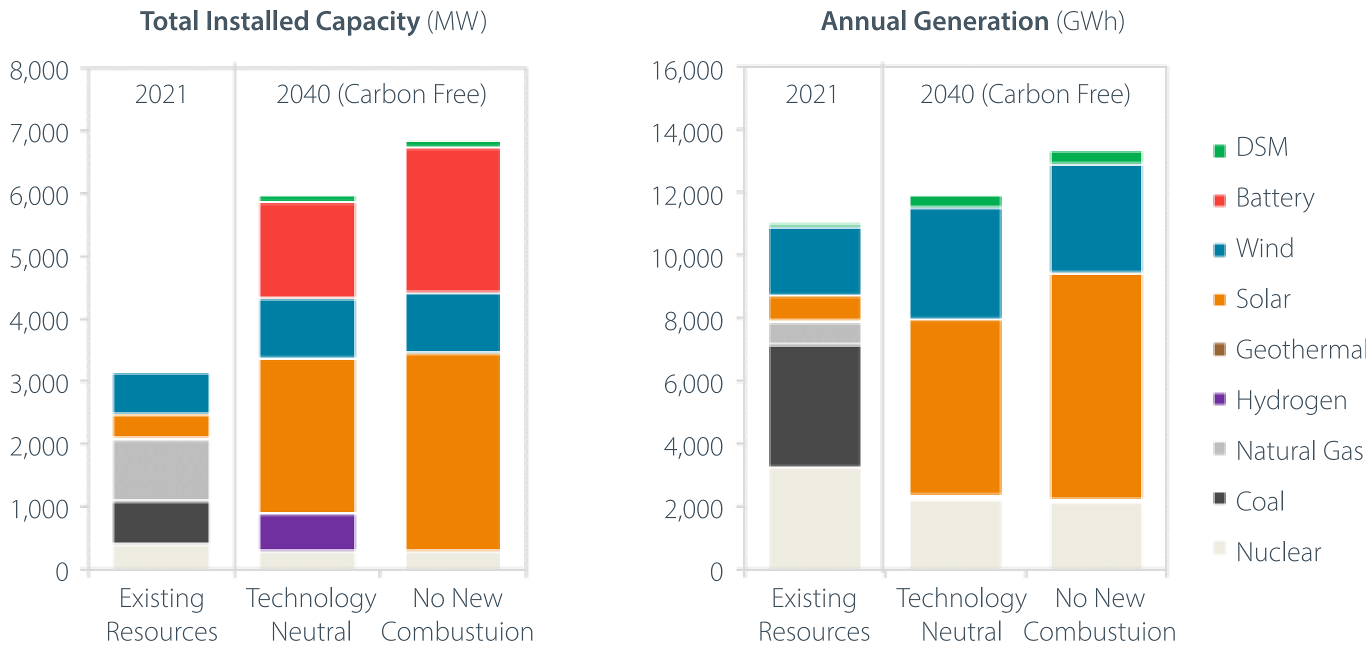

Figure 13. Proposed portfolios for a 2040 system from the PNM 2020–2040 Integrated Resource Plan. DSM = demand-side management.
Source: PNM (2021)

2. How are total costs impacted by the selected portfolio?

Total system costs are valuable model outputs that inform the affordability of a proposed portfolio, and they typically comprise up-front capital investments (and associated financing assumptions), operations and maintenance costs, fuel costs, and transmission investment costs. Therefore, total system costs typically scale with the size of the utility, the extent of investments proposed, and the selected resources. The absolute magnitude of the costs is often less meaningful than the relative magnitude of the costs. For example, if portfolio A and portfolio B differ in costs by 0.1%, the difference might be within the model error, and other factors are more important to determine which portfolio is best.

Depending on goals of the resource planning process, it can also be helpful to translate the total cost reported by the model into other cost factors, such as how different portfolios might impact customers' electricity rates, or how much annual revenue a utility might need to cover the cost of a particular portfolio.

Figure 14 shows an example of modeled costs for a variety of portfolios under different natural gas price futures. The net present value results can be useful to understand the implications of choosing one portfolio over another, as well as how the portfolio might behave under widely varying natural gas price conditions. A case like this also shows how a factor like natural gas price can have a much larger impact on the portfolio costs than other factors shown in the chart.

> *Additional questions to consider:* How large of a cost difference between scenarios is actually meaningful? At what point are two scenarios effectively equivalent in cost? Why was a given cost metric the best one for comparing portfolios or choices?

3. How does the system operate during high-risk periods?

A fundamental piece of resource planning is ensuring that the portfolio of resources can serve load during times of high risk. A simulation of how a future portfolio might perform during those periods can yield important insights. **Figure 15** shows an example of a simulated 2030 grid system for the Grant Public Utility District (in Washington) from their 2022 integrated resource plan. By examining the system operation during this high-risk period, you can evaluate whether the generators can perform as modeled. For example, can the units ramp quickly enough? Or will the utility be able to make the assumed market purchases during the times when the model assumes those purchases are available?

Exploring a case such as this can reveal that the outputs are not reasonable (e.g., that ramp is too steep). Depending on

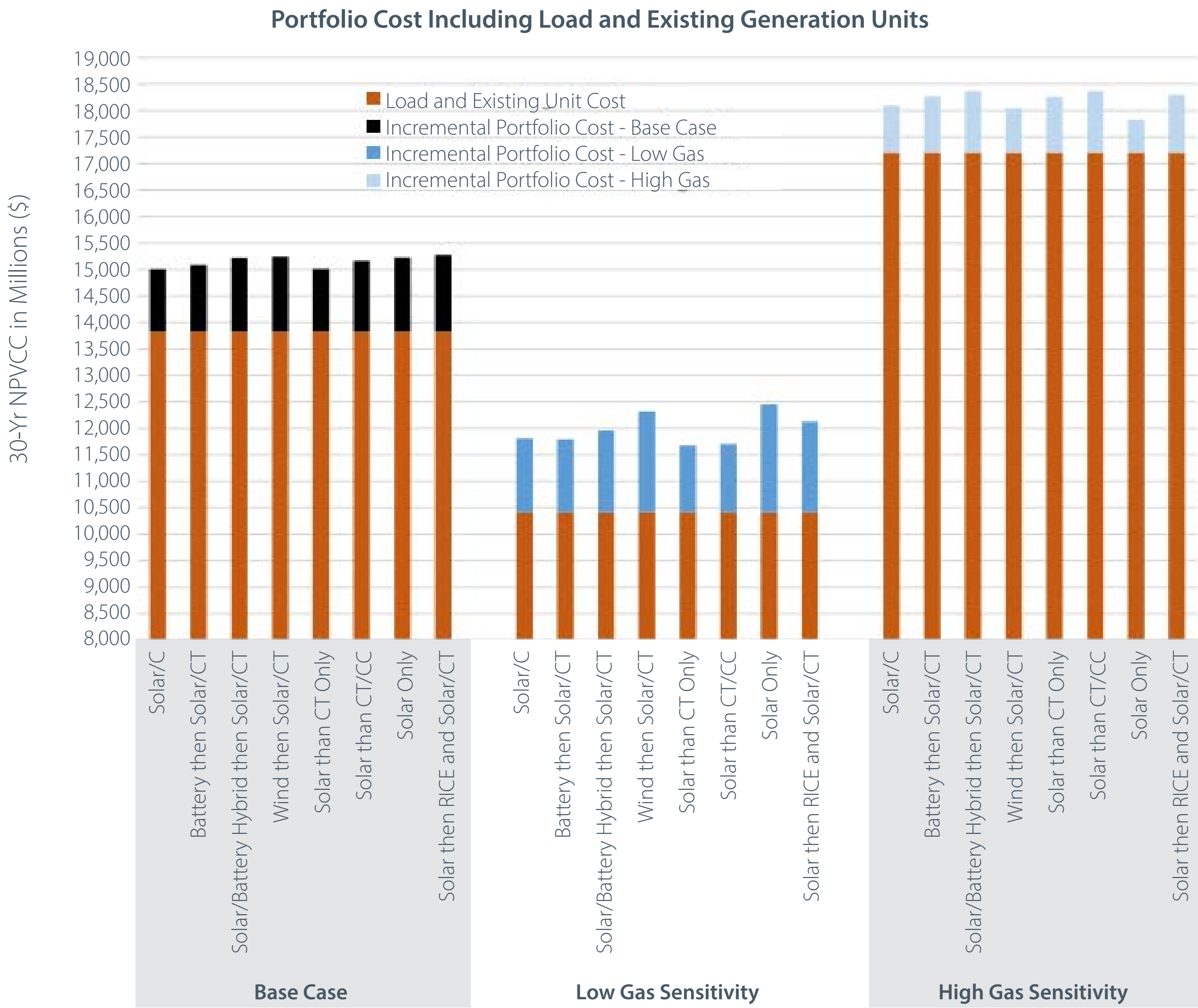

Figure 14. Net present value of customer cost (NPVCC) of potential portfolios from the Oklahoma Gas & Electric 2021 Integrated Resource Plan. CT = combustion turbine, CC = combined cycle, RICE = reciprocating internal combustion engine.
Source: Oklahoma Gas & Electric (2021)

the potential implication of the assumption, it might need to be updated in the model, and the model would need to be rerun. In other cases, the incorrect assumption has negligible impact on results, and it can simply be noted and included in the caveats when evaluating modeling results.

> *Additional questions to consider:* What looks odd to you as you look at a figure showing system operations? Why are units operating the way shown?

4. Do existing generators experience any significant changes in operation?

Capacity factor is the primary operational metric for an individual generation unit or resource type, and it represents the simulated (or realized) generation output divided by the total feasible generation output over the course of a year. Capacity factor is a key metric for understanding the economics of an existing unit, and capacity factors could look very different in the future if a system's resource mix undergoes significant change. For example, the widespread deployment of variable renewable energy resources can lead to reduced capacity factors for fuel-based generation resources. This is because variable renewable resources have no fuel cost, and their widespread deployment typically drives up the value of flexibility—meaning fuel-based generators operate less frequently and at lower capacities.

> *Additional questions to consider:* How are utilization rates of existing plants changing? Do plant operators feel like those changes might be reasonable? Why or why not?

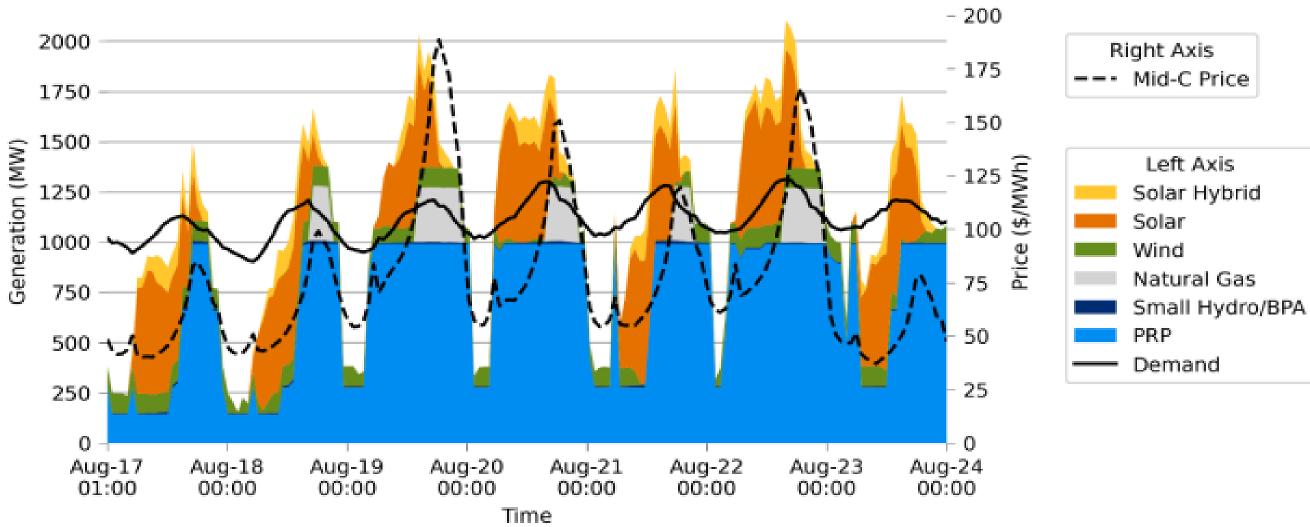

Figure 15. Simulated hourly dispatch for the week with the highest summer peak net demand using a 2030 portfolio, from the Grant (Washington) Public Utility District 2022 Integrated Resource Plan. Mid-C = mid-Columbia, BPA = Bonneville Power Administration, PRP = Priest Rapids Project (a hydropower project).

Source: EES Consulting (2022)

5. Is the proposed portfolio consistent with policies that are specific to the electric sector?

As previously discussed in Question #4 of the Assumptions and Data section, a wide array of local, state, and federal policies introduces restrictions on the future electricity supply mix. Federal regulations require specific investments and operational strategies for emitting generation units. State-level renewable portfolio and clean electricity standards require a specific share of electricity generation to be provided by certain resource types. State and local siting ordinances define whether and where a given resource type can be built. Many policies indirectly influence the future electricity supply mix via incentives and requirements that modify the magnitude and timing of electricity demands.

Assuming that policies are properly represented in the model, the portfolios should be consistent with the policies. For example, **Figure 16** shows an example of a portfolio and how it compares to the renewable portfolio standard requirement. This is one of the ways to make sure that assumptions were properly captured.

> *Additional questions to consider:* Can the utility verify that the portfolios selected will be consistent with policies? Do they account for local, state, and federal policies that influence both the demand for and supply of electricity?

6. Are caveats and limitations of the work discussed?

Modeling and analysis cannot cover every potential condition or situation, so it is important that caveats and limitations are clearly articulated in a plan. One common downfall is when model results are used outside of proper context of the caveats and limitations. Having them accessible helps decision makers more appropriately interpret results. For example, if a model does not represent technologies that might be important for full decarbonization, decision-making using the model could focus on the pathway toward decarbonization, and not the final decarbonized portfolio. The caveats and limitations are also a good place to highlight important uncertainties that could not be included in the modeling work but might still influence the decision-making process.

> *Additional questions to consider:* What are the most important considerations not included in the modeling? Have those considerations been addressed or discussed somewhere?

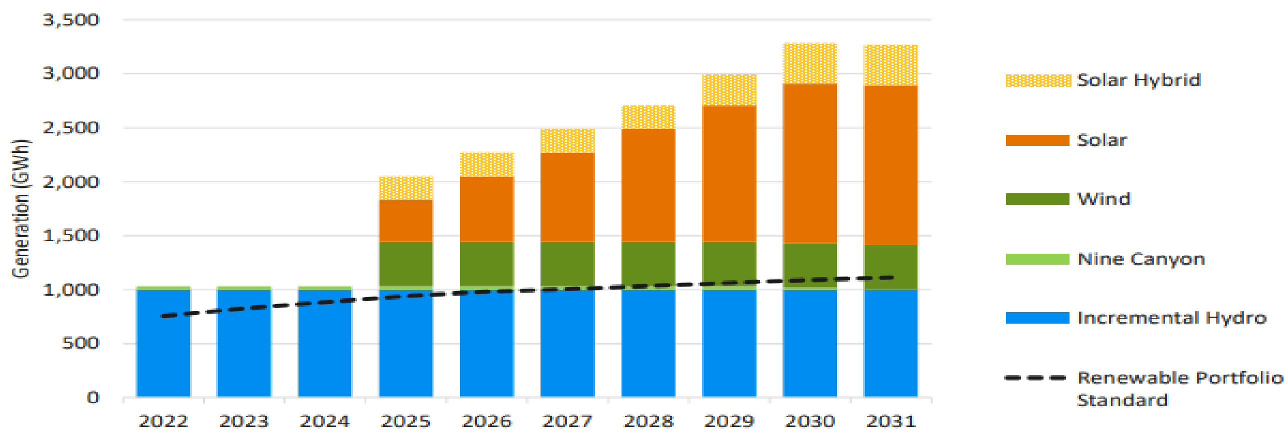

Figure 16. Qualifying generation resources for the state renewable portfolio standard relative to the requirement (shown as the dashed line), from the Grant Public Utility District 2022 Integrated Resource Plan.
Source: EES Consulting (2022)

Methods

Methods designed to capture the complexities of the electricity system have advanced considerably over the past two decades, especially as weather-dependent resources such as wind and solar have become more prevalent. It is important to ensure that the utility's tools and practices have kept up with these changes so that trade-offs among technologies can be properly represented and evaluated. Using an out-of-date tool for planning systems with high shares of wind and solar can lead to poor results.

Because the newer modeling methods can be more complex, we give only a brief introduction to the methods here. Additional details on some of these topics are provided in the Advanced Topics guide (Cole et al. Forthcoming).

Questions

1. How are resources selected within the model?

The model should consider both the cost and value of the resource. If it considers only costs, then it can overinvest in a certain resource without considering the overall value. Take solar for example: The first units of solar might be very valuable, but because all solar produces at essentially the same time, only investing in this resource can lead to a surplus of energy in the middle of the day and a shortfall of energy at night. As this example shows, if models are incapable of capturing the value aspect of resources, they return distorted results, and the portfolio is unlikely to perform as envisioned in the modeling.

Other challenges can arise from forcing the model to treat resources in a very specific way. For example, if a model only allows natural gas peaking plants to run during summer afternoons, then the model will not see other valuable ways those peaking plants might contribute to the system. Or, if there are hard rules in the model, such as for every 1 MW of wind or solar, you need 1 MW of natural gas capacity, then the model is unable to evaluate potentially lower-cost options that do not have that fixed requirement. If models are unable to evaluate a portfolio of independent resources, then it is possible that the internal model requirements for resources can skew the solutions provided by the models.

> *Additional questions to consider:* Why was one resource selected over another resource? Why might some resources only appear in certain scenarios but not others?

2. How does the model determine the availability of weather-dependent and storage resources during system stress periods?

Because stress periods[6] on the power system are often related to weather, it is important to capture correlations between resources and these times of high demand.

6 Stress periods are the times when the system is most strained, and therefore the risk of dropping load is greatest. Traditionally this has occurred during extremes in temperature, such as very cold or very hot days when electricity demand from heating or cooling is greatest.

For example, if stress periods tend to occur on summer afternoons, do those summer afternoons tend to be windy or calm? That affects the ability of wind energy resources to help meet demand during the stress periods. Or if the stress periods occur during winter evenings, solar PV is likely unavailable. Storage availability depends on how it was previously used, meaning if storage was just fully discharged, it cannot be available to help meet load during the stress period.

This evaluation can be complex (and is addressed in the Advanced Topics guide [Cole et al. Forthcoming] in greater detail), and you most likely do not need to fully understand the method used, but it is a good idea to ensure thought was put into capturing correlations among weather-dependent resources and load.

> *Additional questions to consider:* How can you be confident that the selected portfolio will perform as intended? What risks might a given portfolio have for serving load year-round?

3. **How does the model know whether the mix of resources selected will be sufficient to meet load during all hours?**

Because of the computation challenge of modeling the electricity system, some models only simulate how the system operates during a representative set of days or conditions. If representative time periods are not selected properly, the model can choose a portfolio of resources that performs well on the modeled days but performs poorly during extreme events or periods of system stress. Or the model can also assume that fuel is always available, which may not be the case in reality.

> *Additional questions to consider:* What types of conditions are represented in the planning model? Are stress periods explicitly represented in the model? Is a separate model used to ensure that the resulting portfolio will be reliable? How can you have confidence that the portfolio selected by the model will be reliable?

CONCLUDING REMARKS

Becoming proficient in power system planning is a valuable skill; such proficiency plays a critical role in ensuring reliable and sustainable energy systems. As you embark on your own planning, remember it is a dynamic process that requires continual learning, practical experience, and a commitment to staying up to date on industry advancements. With this approach, you and all interested parties can work through key decisions that need to be made as part of the plan. As you engage in the planning process, you will gain greater expertise in the areas discussed in this guide and have a better sense of the right questions to ask to interpret model results—ultimately increasing understanding and improving decision-making for everyone involved.

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