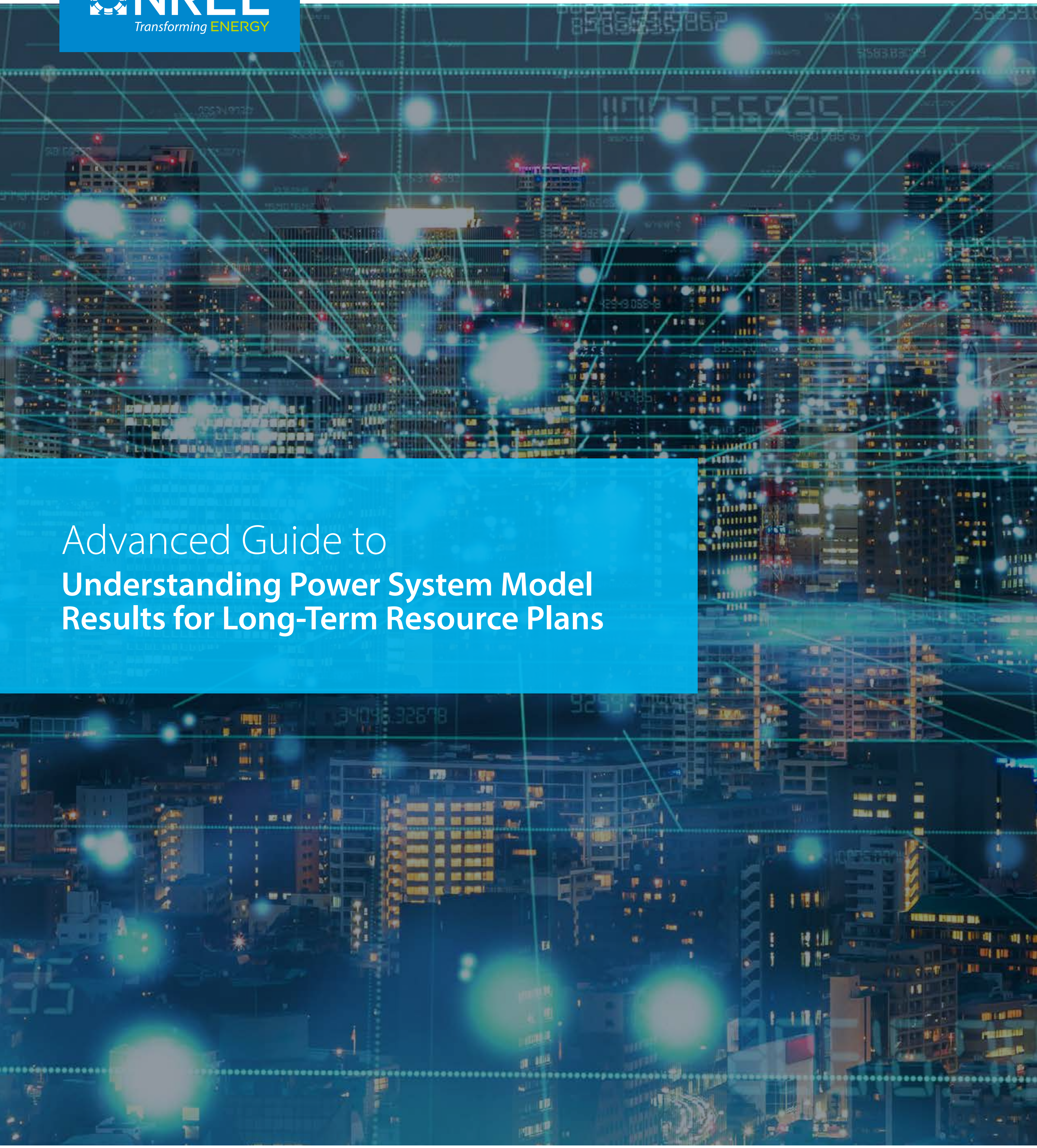

Advanced Guide to Understanding Power System Model Results for Long-Term Resource Plans

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INTRODUCTION

This guide is for public utility commission staff, state energy office staff, and other stakeholders who review model results for utility integrated resource plans (IRPs). It builds on the Beginner's Guide to Understanding Power System Model Results for Long-Term Resource Plans (Cole, Murphy, and Karmakar 2024) and delves into more advanced topics that were not included or not fully covered in the beginner's guide. It is not possible to cover all potential topics that could be relevant to an IRP, so we focus on topics we believe are most relevant to current resource planning best practices.

As with the beginner's guide, we intend for this guide to help improve decision-making in the electricity planning process by strengthening understanding and dialogue between electricity system planners and relevant stakeholders. The following information is designed to allow you to better engage in the planning process by evaluating results, asking questions, and thinking through what is most important.

The three primary topics we cover in this guide are electricity demand evolution, demand-side resources, and resource adequacy. These topics have garnered increasing attention in recent years, hence their prominence in this guide. Other topics are also presented, but their incorporation into the planning process might vary based on the interest and relevance of your local planning entities. The absence of certain topics does not diminish their importance; rather, it reflects the reality that in planning, trade-offs necessitate prioritizing certain aspects over others.[1]

1 See EPRI's State of Electric Company Resource Planning 2023 (EPRI 2023) to view a summary of IRPs and current issues as of 2023. https://www.epri.com/research/programs/069228/results/3002026243

ELECTRICITY DEMAND EVOLUTION

In recent years, there has been relatively modest growth in electricity demand. However, the scale and pattern of electricity demand could change dramatically because of electrification of demand currently met by fossil fuels, including space and water heating and vehicles. This electrification is likely to happen even more rapidly with incentives under the Inflation Reduction Act that are designed to accelerate and expand electrification. **Figure 1** presents an example of a projection of potential growth in the coming decades, showing dramatic growth.

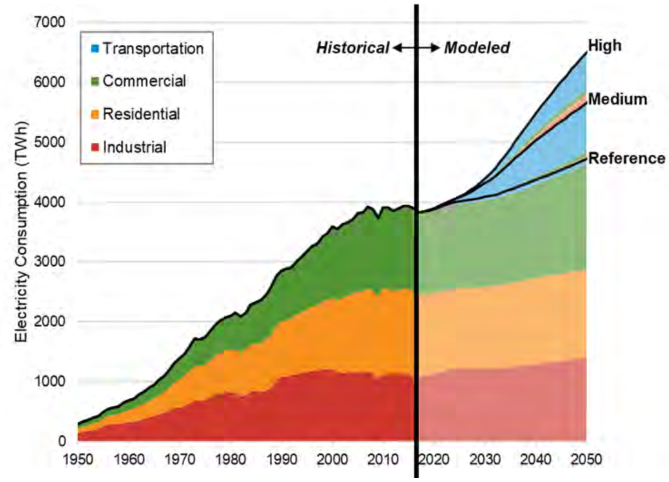

Figure 1. National demand for electricity from various sectors, with three projections for future load growth based on expectations for electrification of end uses such as transportation and heating. *Source: Mai et al.,* https://www.nrel.gov/docs/fy18osti/71500.pdf

Electricity demand varies significantly over the course of the day and across the year, which means utilities must estimate not only the total increase in annual load but also when this additional load will occur. Electricity demand typically reaches its peak during summer afternoons, but this could shift to winter if there is large-scale adoption of electric heating. This could create additional challenges in meeting peak demand, such as the limited ability of solar energy to provide energy during peak demand periods in the winter. There are also considerable uncertainties in predicting when shifts in electricity demand might occur based on consumer behavior and adoption of new technologies such as electric vehicles and heat pumps.

Best practices for estimating future growth in electric demand involves estimating the growth in electric load, the timing of when the load might come online, and the shape of the load. Creating these estimates can include performing bottom-up load modeling that includes the relevant utility service territory details related to service demand requirements and end-use equipment stock such as electric vehicles or building heating equipment type. Service demand requirements are dictated by local weather patterns, the makeup and efficiency of the existing building stock, temperatures set by customers on thermostats and water heaters, and the efficiency of the adopted equipment.[2] If the utility has data or information about its customers' adoption trends, they can use those to make more robust predictions about how much electricity might be used.

The level of detail captured in the analysis of the evolution of electricity demand depends in part on how big the potential change might be. The most important aspect for resource planning is that these issues have been considered and that a deliberate and reasonable decision is made for how they should be captured in the resource planning exercise.

Helpful Resources

- End-Use Load Profiles for the U.S. Building Stock (Pigman et al. 2022) https://eta-publications.lbl.gov/sites/default/files/lbnl_eulp_2022_1208.pdf and https://www.nrel.gov/buildings/end-use-load-profiles.html
- U.S. Building Sector Decarbonization Scenarios to 2050 (Langevin et al. 2023) https://buildings2050.lbl.gov/
- Load Forecasting in Electric Utility Integrated Resource Planning (Carvallo et al. 2017) https://emp.lbl.gov/publications/load-forecasting-electric-utility
- Best Practices in Electricity Load Modeling and Forecasting for Long-Term Power System Planning (Zhou et al. 2023) https://www.nrel.gov/docs/fy23osti/81897.pdf
- Developing Forecasts: Basics & Best Practices (Mims Frick et al. 2023) https://emp.lbl.gov/publications/developing-forecasts-basics-best
- ESIG Long-term Load Forecasting Workshop presentations (ESIG 2023) https://www.esig.energy/event/2023-long-term-load-forecasting-workshop/
- Load forecasting with climate variability for transmission and distribution system planning (Yang and Homer 2021) https://eta-publications.lbl.gov/sites/default/files/combined_pnnl_and_nrel_load_and_der_forecasting_ncep_fin.pdf

2 Efficiency requirements, building standards, and other rules driven by federal, state, or local regulations can influence the adoption of various end-use technologies and should be considered when creating load projections.

DEMAND-SIDE RESOURCES

Demand-side resources in an IRP can include any technology or intervention that modifies the load shape or annual electricity consumption. Examples are shown in **Table 1**. The table includes two types of examples for each category. The first is "prespecified," which means the resource is specified outside of the model that is doing the resource planning. For example, distributed photovoltaics (PV) adoption might be represented using a fixed growth trajectory. The second type is "selected by the model," which means the model decides to invest in or adopt that resource. For example, distributed PV might be selected by the model based on the cost or anticipated customer bill savings. You may also hear the terminology "exogenous" and "endogenous" in place of "prespecified" and "selected by or within the model."

Table 1: Categories and Descriptions of Demand-Side Resources Included in Some Power Systems Planning Models

Category	Description	Prespecified	Selected by Model
Distributed Generation	Customer-sited generation and storage resources	Adoption trend based on history or targets; used to modify load	Iterate with additional model of distributed generation adoption or include directly as a resource option
Energy Efficiency	Providing the same energy service with reduced consumption	Percent magnitude reduction and shape based on history or program targets	Resource options in the model that can be selected if cost-effective
Demand Response	Reducing energy consumption at times of system stress	Reduction in peak load or load during defined event based on program targets	Resource options in the model that can be dispatched at a specified cost
Demand Flexibility	Shifting energy consumption in time or space without reducing total consumption	Load modification based on history or assumed program targets	Resource options in the model that can be dispatched at a specified cost
Pricing	Provide customers with prices that more closely follow the actual cost of electricity production	Modify load based on assumed response to prices	Capture elasticities of end-use demand

Note: "Prespecified" indicates a way to capture that category in a model without the model needing to represent the technology explicitly (exogenous representation); "Selected by Model" indicates the category is explicitly represented as a choice in the model and the model can choose to select it (endogenous representation).3

These demand-side resources are often more challenging to include in resource planning efforts because they can be difficult to characterize (e.g., how will better insulation impact electricity demand given the wide range of buildings in the service territory?) and because their procurement can be difficult to specify (e.g., how much does it cost to reduce peak demand by 1 MW?).

Some of the categories in Table 1 are included more often in utility planning. Distributed generation, energy efficiency, and demand response have been part of utility planning to varying degrees for decades. Both distributed generation and energy efficiency share a similar challenge: They tend to be small, heterogenous resources that must be rolled up to something that can be meaningfully represented in a long-term planning model. Customer decisions to adopt behind-the-meter solar or batteries depend on compensation mechanisms (e.g., net energy metering, rebates, or tax credits), value of backup power, and societal factors such as whether their neighbors have solar. Except through providing incentives for particular technologies, these demand-side resources are largely outside the control of the system planner. A common approach in planning is to pair planning models with estimates of energy efficiency and distributed generation adoption and performance, then incorporate those

3 These categories are names commonly found in resource plans, but many of them overlap. For example, time-of-use pricing is a way to incentivize demand flexibility, so pricing is simply a form of demand flexibility.

estimates as scenarios. That can be done iteratively to make selection of these resources endogenous or as a single passthrough of exogenous data.

Demand response is traditionally a question of customer participation in programs that require specified load reductions during peak events. Encouraging large electricity users to reduce their peak power usage in a cost-effective way is more aligned with how system planners think. However, many demand response programs buy this service a year ahead and penalize it if it is not delivered rather than making dynamic changes as needed. This generally means demand response, alongside energy efficiency and distributed generation, can often be collectively specified as exogenous load modifications to the baseline forecast.

In the traditional planning process, demand-side resources are considered substitutes for supply-side investments. But if we fully value demand-side resources, it requires moving beyond the substitution paradigm of simply swapping one resource for another. Distributed generation and energy efficiency primarily avoid the need for additional energy, whereas demand response primarily avoids the need for investment in additional generation capacity. Many of the location-specific aspects of these resources, such as avoided distribution infrastructure, have not always been included in IRP modeling and analysis. This locational value enhances the ability to evaluate trade-offs of these demand-side resources. And because of losses in the transmission and distribution of electricity, a reduction in 1 MWh of electricity consumed results in more than 1 MWh of avoided electricity generation.

A final element of demand-side resource modeling is performance. Although there is no resource that is always perfectly available, system operators typically have far more experience in predicting the availability and responsiveness of supply-side compared to demand-side resources. Importantly, there is generally high confidence in forecasting and controlling common supply-side resources in planning model assumptions. For example, the responsiveness of operating reserves held by a model to manage differences between forecasted and actual electricity load may be based on historical power plant operations. Operators might be uncomfortable assuming the same level of responsiveness can be achieved by turning down air conditioning or delaying electric vehicle charging. Incorporating selectable demand-side resources in modeling requires close attention to assumptions derived from common characteristics of supply-side resources and may require adjustment for their unique performance characteristics.

Helpful Resources

- The use of price-based demand response as a resource in electricity system planning (Carvallo and Schwartz 2023)an increasing number of states are requiring regulated utilities to file plans that identify distribution system needs, including DERs that can avoid or defer certain types of traditional utility investments cost-effectively. Price-based demand response (DR https://eta-publications.lbl.gov/sites/default/files/price-based_dr_as_a_resource_in_electricity_system_planning_-_final_11082023.pdf

- Still the One: Efficiency Remains a Cost-Effective Electricity Resource (Mims Frick, Murphy, et al. 2021) https://emp.lbl.gov/publications/still-one-efficiency-remains-cost

- Methods to Incorporate Energy Efficiency in Electricity System Planning and Markets (Mims Frick, Eckman, et al. 2021) https://emp.lbl.gov/publications/methods-incorporate-energy-efficiency

- Tapping the Mother Lode: Employing Price-Responsive Demand to Reduce the Investment Challenge (ESIG 2023) https://www.esig.energy/wp-content/uploads/2023/01/Tapping-the-Mother-Lode-Employing-Price-Responsive-Demand-to-Reduce-the-Investment-Challenge.pdf

RESOURCE ADEQUACY

Resource adequacy is defined by the North American Electric Reliability Corporation (NERC) as "the ability of the electricity system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements." Reliable operation of the electric grid is often measured and evaluated separately on the distribution network and the transmission and generation network. Recent events[4] have highlighted concerns about resource adequacy across the United States, including the western heat wave event (2020),[5] Winter Storm Uri (2021),[6] and Winter Storm Elliot (2022),[7] as shown in **Figure 2**.

Provision of resource adequacy is a core focus of integrated resource planning and the associated modeling performed for the planning.[8] This specific area of focus presents at least three difficulties in long-term planning models:

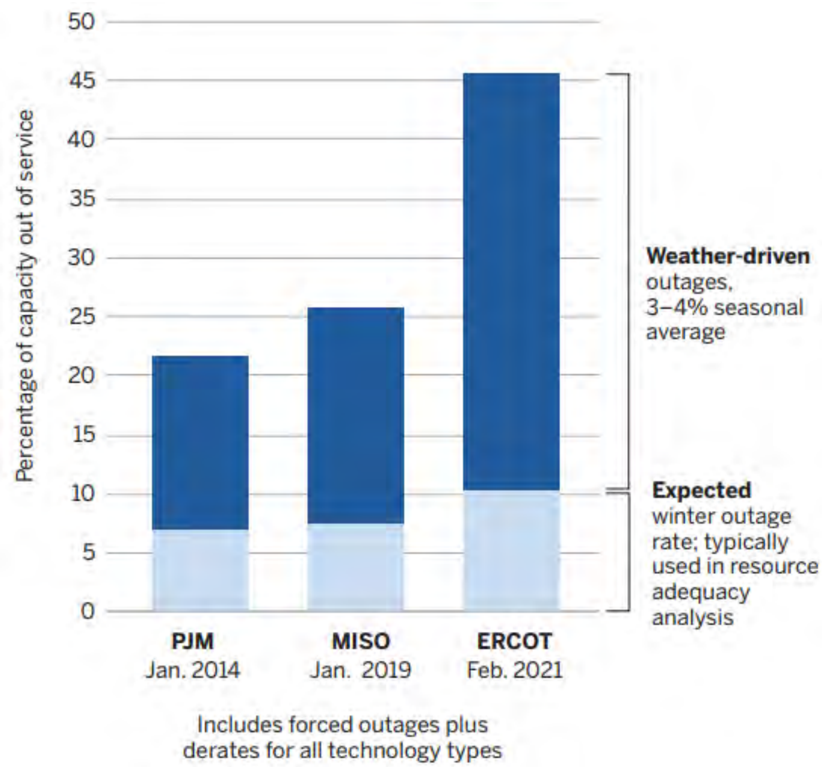

Figure 2: Percentage of unplanned outages during recent cold weather events.
Source: Energy System Integration Group (ESIG 2021).

1. There are inherent trade-offs between resource adequacy and cost that can make it challenging to select a resource adequacy target.
2. Resource adequacy is a property of the full electricity system, including other parts of the system to which a given utility is connected via transmission. This makes it challenging to define resource adequacy jurisdiction and quantify the resource adequacy contribution of individual generators, transmission lines, or other resources.
3. Events that pose the greatest risk to reliable operation of the bulk power system involve combinations of weather, electricity load, and generation availability that are, by definition, uncommon. Because of this, it is difficult to curate data sets that accurately characterize these high-risk events.

4 See Explained: Causes of Three Recent Major Blackouts and What Is Being Done in Response https://www.nrel.gov/docs/fy24osti/87308.pdf

5 caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

6 ercot.com/files/docs/2021/04/28/ERCOT_Winter_Storm_Generator_Outages_By_Cause_Updated_Report_4.27.21.pdf

7 pjm.com/-/media/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.ashx

8 If you are interested in learning more about resource adequacy in North America, read NERC's overview of its jurisdiction in assessing long-term resource adequacy (https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2022.pdf) and the Federal Energy Regulatory Commission's overview of energy markets (https://www.ferc.gov/sites/default/files/2020-06/energy-primer-2020_0.pdf), including those for resource adequacy. In addition, NERC publishes seasonal winter and summer short-term assessments of regional resource adequacy using much of the same terminology and methods described later in this document (see https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2022.pdf and https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2022.pdf).

Defining Metrics

No generator is perfectly reliable. Therefore, no power system is perfectly reliable. Any addition of generation or other resources with some probability of being available when needed improves reliability, but it comes with a cost. A common first step in planning is to select a target level of resource adequacy that balances costs of reliability issues and costs of building a larger, more expensive power system. These targets might be already determined by a regulating body, or they simply might be the traditional value that has been used for decades. Depending on what was done to select a resource adequacy target, it might be valuable to iterate on various levels of resource adequacy in the resource plan to better understand the trade-offs of reliability and cost. **Table 2** lists some commonly used target metrics for resource adequacy.

Each metric can be translated to a quantitative measure of resource adequacy. For example, loss-of-load expectation (LOLE) targets are commonly "1 event-day in 10 years" (0.1 LOLE). This target level of resource adequacy is then often translated to a planning reserve margin (PRM). The PRM is the quantity of generator capacity above the expected peak demand needed to meet the target reliability metric in the future system (that presupposes there is a target reliability metric). Large planning areas—at least multiple gigawatts but often tens or hundreds of gigawatts of installed capacity—in North America that mostly use natural gas, oil, coal, and/or nuclear-fired power plants commonly have 10%–20% PRM targets.

As power systems planning evolves to incorporate much higher quantities of variable (solar PV, wind) or energy-limited (batteries) resources, better data on future weather patterns, and the value of electricity to consumers at different times, it complicates the assessment of resource adequacy. That includes reconsidering the appropriate reliability target, metric, and quantity of procured resources.

Valuing Resources

Resource adequacy is a systemwide property that depends on the full portfolio of generators and transmission. This systemwide aspect was evidenced by well-known events like Winter Storms Uri and Elliot and summer heat waves. These events affect broad geographic areas and require detailed, multifactor root cause analyses. However, system adequacy creates an analytical challenge of how to evaluate the contribution of individual resources to system-level resource adequacy.

Table 2: Common Resource Adequacy Metrics

Metric	Description	Pros	Cons
Planning reserve margin (PRM)	Percent of rated capacity above the expected peak demand	Easy to interpret; relatively easy to calculate	No inherent connection to a reliability level (e.g., is 15% PRM enough?)
Loss-of-load expectation (LOLE)	Expected count of distinct periods ("events") with unserved energy demand in a studied time horizon	Interpretable as experienced events, commonly used in industry for decades	Does not incorporate magnitude of event; no standard time definition of an event
Loss-of-load hours (LOLH)	As above but measured in hours instead of longer time intervals (e.g., day or event)	As above but with clearly defined time interval for an event	Does not incorporate magnitude of event
Loss-of-load probability (LOLP)	Probability of a loss-of-load event in a time interval	Quantifies event probability at a given time	Not easily interpreted as systemwide metric unless converted to LOLE/LOLH; does not capture magnitude of outages
Expected unserved energy (EUE)	Average quantity of unserved energy (e.g., in megawatt-hours) over a studied time horizon	Incorporates magnitude of unserved energy quantity, not just binary event	Does not differentiate the value of unserved energy as a function of magnitude or time
Normalized expected unserved energy (NEUE)	As above but normalized per unit of electricity demand on the system	As above but normalizes for system electricity demand	As above but normalizes for system electricity demand

The ideal approach will assess all resources fairly, even if they have very different resource availability profiles—like natural gas, solar PV, and energy storage. The challenge is especially important in regions where payments accrue to individual resources based on their expected or observed contribution to system adequacy.

A commonly used metric to assign resource adequacy to individual resources is the capacity credit, which is a measure of a resource's expected ability to contribute to system needs during the times of highest expected system stress. That stress has commonly occurred during the hours with the highest electricity load net of expected available wind and solar generation. Capacity credit is measured either in terms of capacity (kW, MW) or as the fraction of its nameplate capacity (%) and is sometimes called capacity value, although this can also refer to the monetary value of physical capacity. A resource's capacity credit can be quantified by calculating its effective load carrying capability (ELCC), which is the increase in electric load across all hours of the year(s) that can be accommodated by adding the resource while keeping the resource adequacy of the system constant. For example, if a given system can accommodate 40 MW of additional load in all hours with the addition of a 100-MW solar PV resource at equal risk (e.g., 0.1 LOLE), the solar PV resource has a 40-MW or 40% capacity credit on that system.

An ELCC-based approach or similar approximation is commonly implemented in long-run planning models used in IRPs to compare resource alternatives on a comparable playing field. It can be computationally intensive to scale this approach and calculate individual resource ELCCs across thousands of weather and generator unavailability scenario years and to consider that resource capacity credit changes as electricity loads and generation resource mix change.[9] A simplified and more commonly used approach employs high electricity load net of wind and solar generation hours and/or assesses a more limited number of time intervals. This approach works well if it matches the actual conditions that stress power system operations, but it is important to curate and select appropriate weather and electrical load data.

High-Quality Data for Uncommon and Future Events

Power systems across North America are undergoing significant change with an influx of wind, solar, and storage resources; new load growth from electric vehicles, data centers, and electrified heating and cooling loads; and the need to plan for extreme and/or changing weather patterns affecting all resources availability. Resource adequacy increasingly requires factoring in the interdependency of difference resources and weather conditions. For example, it can be important to consider natural gas generation availability on the gas pipeline network during freezing temperatures, high gas heating demand conditions, and the effects of weather on the availability of wind, solar, and hydropower generation resources. In addition, demand-side resources such as managed electric vehicle charging or air conditioner demand-response depend on specific customer conditions. This now requires planning models to consider longer time frames that also encompass hours when the electricity demand might not typically be very high but are important for storage resources to be prepared for potential increased demand later. Changes to temperature and weather patterns in an evolving climate are also requiring new data that are developed by augmenting historical data. Decreased costs of software and hardware that monitor near-real-time electricity consumption can enable better understanding of the cost of shifting or forgoing targeted electricity loads at times of high risk. Still, to include all these evolving considerations in planning, it will be necessary to connect increasingly large data sets on climate, weather, electricity consumption, and characteristics of available generators. By making these connections, resource adequacy can be modernized to ensure there are enough resources on the future grid.

From Planning to Operations

Good planning is necessary but not sufficient for reliable operation of the power system. This section has focused on prospectively planning the system using modeling with high-quality data to ensure sufficient resources are available and serve electricity loads that are fundamental to a functioning modern society. In practice, however, sufficient resources must be translated into operations. Although not covered in detail in this guide, an important aspect in planning involves distinguishing between expected and observed system conditions. Drawing lessons from past events, power system operators in North American market jurisdictions have increasingly imposed fines for resources that do not meet their assigned prospective resource adequacy obligation. For example, if a generator has a 50% capacity credit, was it available 50% of the time when needed? Planning does not stop with modeling a prospectively adequate system and can also include incentives or other measures to help ensure the system operates as planned.

9 For example, a system with a summer afternoon peak load derives more reliability benefit from the first unit of installed solar capacity than from later units that make generation availability increasingly coincident with the original peak load. A more complete treatment of this phenomenon is the subject of Schlag et al., https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf.

Helpful Resources

- Assessing the Resource Adequacy and Community Impacts of an Evolving Grid: Considerations for State Regulators (Schleifer et al. 2023) https://publications.anl.gov/anlpubs/2023/07/183578.pdf
- A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems: Institutional and Technical Dimensions (Carvallo et al. 2023) https://emp.lbl.gov/publications/guide-improved-resource-adequacy
- Resource Adequacy for State Utility Regulators: Current Practices and Emerging Reforms (NARUC 2023) https://pubs.naruc.org/pub/0CC6285D-A813-1819-5337-BC750CD704E3
- Explained: Maintaining a Reliable Future Grid with More Wind and Solar (NREL 2024a) https://www.nrel.gov/docs/fy24osti/87298.pdf
- Explained: Reliability of the Current Power Grid (NREL 2024b) https://www.nrel.gov/docs/fy24osti/87297.pdf

OTHER TOPICS

The remainder of this document highlights important topics that are newer and rapidly evolving and for which best practices are still being developed. Their incorporation into planning processes might vary based on interest and relevance, but regardless, they are good to be aware of.[10]

Clean Energy Scenarios

Many cities, states, utilities, and other jurisdictions have adopted 100% clean energy standards. In some jurisdictions, these standards are goals; in others, they are mandated and have penalties for noncompliance. Representing a 100% clean energy standard within a planning model often requires additional model development or capabilities. Several elements are important to consider when evaluating clean energy scenarios, including whether the scenario is a core scenario or a sensitivity scenario that makes adjustments from the core scenario. The first element to consider is the definition of the clean energy standard, which includes many dimensions on its own:

- What technologies are eligible for a clean energy credit and therefore count as "clean"? For example, does a new proposed carbon capture plant with a 95% capture rate get full credit, partial credit, or no credit?
- How are imports and exports treated? Does power sent to another region count for or against the standard?
- Is the clean energy requirement based on sales, generation, or something else? If it is based on sales, transmission and distribution losses would not be part of the requirement and can be covered by non-clean resources unless otherwise stated as part of the clean energy standard. Also, a standard based on sales can be impacted by resources that reduce sales, such as energy efficiency or behind-the-meter generation.
- Does the requirement include any temporal matching (i.e., synchronizing the generation or supply of electricity with the electricity demand throughout the day or across different seasons)? For example, if a utility overproduces clean energy during part of the year, can it rely on other resources during other parts of the year if over the course of the year it will have generated enough to meet the requirement in aggregate?
- Are offsets or alternative compliance payments allowed? For example, can a utility continue to operate a gas peaking plant at a low utilization rate and offset the emissions or generation using some other approved mechanism?

The second element to consider with a clean energy scenario is the availability within the model of technologies needed to meet the clean energy standard. Models that rely only on wind, solar, and storage might find it challenging to identify solutions that can meet a 100% clean energy standard. There are a variety of strategies for having a fully clean energy system, subject to the definition of the requirement as discussed previously. **Table 3** summarizes six of those options.

When evaluating model results for 100% clean energy scenarios, it is important to understand what was modeled (e.g., the definitions, the technology availability) to determine the scope and limitations of any scenarios presented.

10 A list of general resources for topics in this area has been compiled by Lawrence Berkeley National Laboratory and is available under the "Resources" tab at https://emp.lbl.gov/projects/state-TA-program/.

Table 3. Summary of Strategies for Reaching Full Power-Sector Decarbonization

Strategy*	Example technologies	Economic factors[b]	Resource constraints	Technology maturity	Other considerations
Ideal solution	n/a	low capex, low opex	low	high	low environmental impact, synergistic interactions with other sectors
Variable renewable energy	wind, solar photovoltaics	low-medium capex, low opex	medium	high	electrical transmission and storage, land use, social acceptance, weather dependent
Other renewable energy	geothermal	medium-high capex, low opex	high	high	geographical constrains
	hydropower	medium-high capex, low opex	high	high	geographical constraints, shared water resource
	biopower	high capex, medium opex	high (feedstock)	high	biomass sustainability and competition
	biogas and biodiesel combustion turbine	low capex, high opex	high (feedstock)	medium	biomass sustainability and competition
Nuclear and fossil with carbon capture	advanced nuclear	high capex, medium opex	medium	medium	security, supply chain, regulatory and cost uncertainties
	fossil with carbon capture and storage	high capex, medium opex	medium	low	upstream emissions, CO_2 transport and sequestration
Seasonal storage	H_2 combustion turbine	low capex, high opex	low	low	H_2 storage and transport, H_2 competition
	H_2 fuel cell	potential for low capex, high opex	low	low	H_2 storage and transport, H_2 competition
Carbon dioxide removal	bioenergy with carbon capture and storage	high capex, [c] high opex	medium-high	low	biomass sustainability and competition, CO_2 storage and transport
	direct air carbon capture and storage	high capex,[c] high opex	low	low	CO_2 storage and transport
Demand-side resources	varied	low capex, uncertain opportunity cost	unknown	medium	communications and control equipment, reliability

a Many of the six strategies listed will also be used for the first 90% and, for these, the table focuses on additional amounts used to solve the last 10%.
b Capex refers to capital cost expenditures. Opex refers to operating cost expenditures.
c Enables continued use of existing or new low capex resources.

Source: Reproduced from Mai et al. at https://www.cell.com/joule/pdf/S2542-4351(22)00405-6.pdf.

Environmental, Energy, and Climate Justice

The current energy system has resulted in significant inequity in many parts of the country. Exposure to pollution and other negative impacts of the current energy system are unequally distributed by race and income class, as are the benefits of the energy system. For example, grid hosting capacity, distributed solar adoption, and electric vehicle adoption are all lower in majority-Black and Hispanic communities even when income, home ownership, and other factors are controlled.[11] Across the energy system, low-income communities and communities of color bear more of the negative effects of our energy infrastructure, and higher-income and white communities have access to more of the benefits. These challenges are referred to as energy justice, environmental justice, and climate justice, which all focus on achieving equity in energy, environmental, and climate impacts as well as remediating existing burdens on disadvantaged communities.[12]

To begin incorporating energy, environmental, and climate justice into the IRP process, planners might want to consider the following steps:

1. Communities can be meaningfully involved in the energy planning process. If possible, intervenor funding[13] should be provided upfront for community-based organizations to advocate for their constituents. When public meetings are held, transportation and childcare could be provided along with interpretation services during the meeting.
2. Community input and information around demographics, housing type and quality, energy burden, and pollution can be included in the scenario design for the IRP process and, if possible, in the model.
3. Externalities can be internalized into the model. For example, a cost can be assigned to energy burden, air pollution, or the placement of new fossil fuel generation in communities already burdened by existing generation. Negative costs, or benefits, can also be assigned to positive impacts such as battery energy storage that reduces peaker plant emissions or demand-side technologies that increase energy independence in disadvantaged communities.

A best practices approach to planning is to use the three main categories of justice in the IRP process: recognition justice, procedural justice, and distributive justice.

Recognition Justice

At this stage, define who is explicitly recognized in the model. This can be reflected in indices or characteristics used to identify different subpopulations or subregions in the model. To define these metrics, modelers may want to conduct a literature review and engage with community-based organizations to understand risks, opportunities, and historic harms that affect a specific place. This will inform a concrete set of indices that will capture different subpopulations in the model.

Procedural Justice

Routinely and meaningfully engage with recognized communities to define metrics of success. Affected communities must have a voice in defining the priorities, which should be reflected in the objective function of the model and primary metrics the model considers. Several authors have created rubrics to better understand how well community voices are centered in decision-making.[14]

Distributive Justice

Distributive justice can be captured in two ways: 1) ex-post analysis of the distributional impacts from the modeled solution across the subpopulations identified in the recognition justice or 2) ex-ante during design to separately capture the impacts on different subpopulations using appropriate metrics. The latter approach is best practice because it allows a better understanding of the distributional impacts of a proposed energy decision as the decision is made in the model. By adopting the ex-ante method, modeling can create different options that come close to being the most cost-effective solutions but achieve other goals, such as reducing energy burden or pollution in disadvantaged communities.

11 See Reames (2020); Sunter, Castellanos, and Kammen (2019); Barbose et al. (2021); Bednar, Reames, and Keoleian (2017); Wilson et al. (2019); Hardman et al. (2021); Lee, Hardman, and Tal (2019); Tong et al. (2021); and Brockway, Conde, and Callaway (2021).

12 See Baker, DeVar, and Parkash (2019) and Spurlock, Elmallah, and Reames (2022).

13 See NARUC (2021) https://pubs.naruc.org/pub/B0D6B1D8-1866-DAAC-99FB-0923FA35ED1E for more information.

14 See Emerald Cities Collaborative and Poder (2020) and Ross and Day (2022).

Resilience

Discussions and investments around resilience of the electricity grid have grown because of our economy's increasing reliance on electricity, the aging of our grid infrastructure, and growing and expanding threats to the grid related to natural hazards and intentional efforts to cause damage and disruption.[15] Though the concept is closely related to reliability and resource adequacy, resilience tends to focus on extreme occurrences or unusual situations that significantly challenge the grid's ability to function over a large geographic area, such as Winter Storm Uri, record-breaking wildfires in the western United States, and hurricanes. Resilience-testing events fall outside of the normal planning paradigm; in other words, they are usually left out when planning and assessing the reliability of the power grid.

Larger, system-level models struggle with representing resilience events for many reasons: insufficient data (because these events are rare and localized), the complexity associated with interdependent systems (e.g., electricity and natural gas), and the relative ambiguity of the concept of resilience itself. Planning models are typically designed to generate a cost-effective portfolio of resources that can satisfy well-defined reliability requirements, but resilience requirements remain largely undefined, and the value of resilience is highly uncertain because it depends on local conditions and context. As a result, proposed utility investments to improve resilience primarily fall outside of long-term planning models. Indeed, there is a large body of work focused on planning to support improved resilience at individual sites, where a single customer is both responsible for the investment cost and receives the associated benefits.

In response to recent events, utilities have sought to improve system-level resilience through strategically placed microgrids, "public safety shutoff events," increased investment in fuel-based generation assets, and increasing reliance on electricity supply and crews from neighboring regions. Planning models for islanded microgrids can be used to strategically place microgrids to provide the greatest resiliency benefits, which can take many forms. For example, in territories that commonly experience severe hurricanes, a microgrid could be strategically placed to power a utility staging area to accelerate response, recovery, and grid restoration activities. Or, a strategic microgrid might be placed to ensure critical community services are available for those with the greatest need.

Enhanced system-level modeling capabilities could support resilience planning and yield lower-cost resilience solutions. More effective communication and coordination between utilities and states could also support resilience planning. States are expected to play a more active role in resilience planning because of provisions in the Infrastructure Investment and Jobs Act that encourage their involvement. Coordination between utilities and states could help maximize societal benefits by ensuring that investments are targeting the intersection of electric grid ***and*** community resilience.

Integrated Transmission and Distribution Planning

Generation, transmission, and distribution planning typically happen relatively independently from one another because of the complexities of integrating them into one process. For example, the timing and uncertainty of building a long-distance transmission line make it challenging to rely on as a true option in a planning study until some of that uncertainty has been removed. On the distribution side, planning suffers from many of the issues discussed in the demand-side resources section, where the number and variety of distribution assets are challenging to incorporate in traditional bulk power planning models.

Despite these challenges, improvements have been made to facilitate better communication across generation, transmission, and distribution planners and enable understanding and coordination among the groups of planners. For example, many IRP processes now include review meetings with staff from generation, transmission, and distribution, enabling these staff to interact with one another and with stakeholders about potential overlapping solutions. When these groups communicate and work together, they ensure they share consistent assumptions and long-term visions in planning exercises.[16] For instance, if transmission and distribution planners understand that storage is a least-cost resource for meeting resource adequacy needs, they can better identify locations for storage. The strategic placement can maximize the benefits of storage for the transmission system and potentially eliminate the need for transmission or distribution upgrades.

Transparency in Modeling and Assumptions

Because electricity system planning models are complicated, it can be challenging to truly understand

15 See https://www.nrel.gov/security-resilience/energy-resilience.html, https://www.sandia.gov/resilience/ , and https://www.anl.gov/ccrds.

16 See https://www.naruc.org/committees/task-forces-working-groups/retired-task-forces/task-force-on-comprehensive-electricity-planning/home/ for more information and resources in this area.

whether they are performing well without looking more closely at their assumptions or methods. Activities and methods to make these assumptions more accessible can enable stakeholders to better engage in the process. That might include using an open-source model, where all code and inputs are available for stakeholders to view and even run on their own. In addition, publishing spreadsheets with input assumptions, such as technology costs or load growth, makes it easier for stakeholders to review the information.

Another way to add transparency and credibility is to allow stakeholders to provide feedback throughout the IRP modeling through a review process or team rather than just at the end. For example, a review committee might meet monthly and discuss a different topic area each time. The review process creates a venue for the utility to prepare information about assumptions or methods that might be too detailed for the final official IRP document but can be shared and discussed in the more informal environment of a meeting.

CONCLUDING REMARKS

In the world of energy planning, every decision involves trade-offs. Though there are always more detailed, accurate, or sophisticated methods to treat complex planning issues, they often demand more time, expertise, and resources. Determining where to invest more effort becomes very important when providing feedback on a resource plan, ensuring it is as useful and beneficial as possible. As you delve deeper into understanding the electricity system, its models, and long-term planning, you will improve your ability to evaluate these trade-offs, ultimately elevating the value of the planning process and the value of electricity systems to modern society—despite uncertainties ahead.

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