NOVEMBER 2024

# BEST PRACTICES IN INTEGRATED RESOURCE PLANNING

A guide for planners developing the electricity resource mix of the future

Synapse Energy Economics, Inc.

BERKELEY LAB

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# Acknowledgments

The U.S. Department of Energy (DOE) Office of Electricity provided funding for Lawrence Berkeley National Laboratory's work described in this study, and partial funding for Synapse Energy Economics' contributions, under Contract No. DE-AC02-05CH11231. The Energy Foundation provided partial funding for Synapse Energy Economics.

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The authors thank Joe Paladino, U.S. Department of Energy (DOE) Office of Electricity, for supporting Lawrence Berkeley National Laboratory's contributions to this guide and partially funding contributions by Synapse Energy Economics. We also thank the following individuals for reviewing a draft of the guide. Individuals and affiliations are listed for identification purposes only. Participation as a reviewer does not indicate support for this document in whole or in part.

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# Contents

# Executive summary

In 2013, Synapse Energy Economics prepared a report on best practices in integrated resource planning (IRP) for electric utilities (Synapse 2013). In the decade since, the U.S. electricity sector has been in transition. Many aging fossil fuel plants retired as operational costs increased and environmental regulations placed pressure on power plant air emissions and water pollutants. Renewable energy resources were deployed at an increasing pace due to declining costs and favorable policies and incentives. Electrification of transportation and buildings, and greater deployment of distributed energy resources, began to impact utility assessments of grid needs.

While electricity loads grew just 2.6 percent between 2014 and 2023, we are now entering a period of projected load growth with rapid expansion of data centers and industrial and manufacturing loads, in addition to increasing loads from electrification. Utilities, regulators, and regional grid operators are wrestling with the challenges this presents in terms of affordability, sustainability, reliability, and resilience.

The trend toward increasing loads coincides with a temporary slowdown in renewable energy deployment as the industry recovers from inflation and supply chain challenges. Some utilities have responded with plans to extend the lives of potentially uneconomic coal plants or add new natural gas assets over the next 5 years, or both. This may extend reliance on resources that many states seek to phase out to achieve decarbonization and other electricity transition goals. At this turning point, robust and forward-thinking IRP is as important as ever to ensure utilities can meet the needs of their customers while continuing to work toward broader commitments utilities have made to communities and regions in which they operate.

This guide updates and expands the recommendations in Synapse's earlier report and outlines IRP best practices for electricity systems undergoing a major transition. The guide is for resource planning professionals and stakeholders involved in resource planning processes. This diverse group of people includes utility personnel tasked with conducting resource planning and making investment decisions, state regulatory commissions that develop planning guidance and oversee the resource planning process, and stakeholders that represent a wide range of interests—utility consumer advocates, environmental groups, industrial customers, local governments, independent power producers, and many others.

## Definition: Integrated Resource Plan

An IRP is a power system plan for a vertically integrated electric utility’s power system plan for to meeting forecasted electricity demand over a specified future period.

- The IRP process provides resource planners with a framework for evaluating plausible futures for the utility's electric system and receiving input from stakeholders.
- The objective of an IRP is to demonstrate which resource portfolio —including supply- and demand-side options—is most likely to be optimal in the face of risks and uncertainties.
- IRPs provide information on electricity system costs, risks, reliability, and trends and answer important questions that affect electricity consumers and utility investors.

The recommendations in this guide are informed by our experience working with a variety of these audiences and our extensive review of IRP reports and proceedings. The utility-specific examples we cite throughout this guide serve to illustrate both best practices and shortcomings; they are not endorsements or indictments of specific utilities. Instead, the examples are intended to provide clarity on practices we recommend or discourage. We aim to be comprehensive in the topics we cover and best practices we offer. The best practices we recommend are based on our collective experience; they are not the only reasonable approaches to various aspects of resource planning.

The guide offers 50 best practices across the following components of the IRP process:

- Designing a transparent and inclusive stakeholder engagement process
- Integrating resource adequacy
- Developing robust model inputs
- Designing scenarios and sensitivities
- Running the models
- Evaluating and communicating results
- Integrating IRP processes with other planning processes, procurement, and utility proceedings

Each best practice includes explanations and examples. Some recommended IRP approaches represent current best practice, while others are aspirational for future improvement. The following checklist summarizes all of these recommended practices.

# Best Practice Checklist

## I. Stakeholder engagement

- **Best Practice 1:** Use an inclusive stakeholder process
- **Best Practice 2:** Engage technical stakeholders in IRP modeling

## II. Resource adequacy

- **Best Practice 3:** Link resource adequacy assessments with resource planning
- **Best Practice 4:** Apply consistent accreditation frameworks to all resource types
- **Best Practice 5:** Use a regional perspective to plan for resource adequacy

## III. Developing model inputs

- **Best Practice 6:** Use up-to-date inputs and assumptions
- **Best Practice 7:** Recognize historical data limitations

**Load Inputs**

- **Best Practice 8:** Develop a load forecast for the expected future
- **Best Practice 9:** Incorporate load flexibility into electrification forecasts
- **Best Practice 10:** Plan ahead for large growth
- **Best Practice 11:** Transparently represent distributed generation and storage

**Supply-side resource inputs**

- **Best Practice 12:** Use accurate assumptions for the costs of new resources
- **Best Practice 13:** Represent the full cost and risk of advanced technologies
- **Best Practice 14:** Include realistic assumptions about resource availability timing, without unnecessary constraints
- **Best Practice 15:** Limit renewable integration cost adders
- **Best Practice 16:** Model all avoidable forward-going resource costs
- **Best Practice 17:** Model battery energy storage options
- **Best Practice 18:** Be consistent in treatment of emerging technologies

**Demand-side resource inputs**

- **Best Practice 19:** Ensure thoughtful and consistent assumptions for demand-side resources
- **Best Practice 20:** Model and bundle demand-side resources carefully
- **Best Practice 21:** Ensure consistency with IRP scenarios
- **Best Practice 22:** Incorporate all relevant benefits for demand-side resources

**Market inputs**

- **Best Practice 23:** Use reasonable market interaction assumptions

**Fuel and commodity inputs**

- **Best Practice 24:** Model fuel supply limitations
- **Best Practice 25:** Evaluate the impacts of gas price volatility and coal supply constraints

**Transmission inputs**

- **Best Practice 26:** Consider transmission alternatives and infrastructure expansion
- **Best Practice 27:** Properly justify bulk power system interconnection costs and constraints

## IV. Designing scenarios and sensitivities

- **Best Practice 28:** Model a base case that allows for easy comparison
- **Best Practice 29:** Design scenarios to evaluate uncertainty and risk
- **Best Practice 30:** Plan for and incorporate important regulatory factors

## V. Running the models (and iterating)

- **Best Practice 31:** Thoughtfully select capacity expansion and production cost models
- **Best Practice 32:** Thoughtfully select a geographic model scale
- **Best Practice 33:** Thoughtfully define the appropriate study period
- **Best Practice 34:** Thoughtfully select the appropriate time granularity for production cost modeling
- **Best Practice 35:** Calibrate the production cost and capacity expansion models
- **Best Practice 36:** Let optimization models optimize
- **Best Practice 37:** Base power plant retirement decisions on forward-looking costs
- **Best Practice 38:** Use modeling parameters that capture the value of battery energy storage
- **Best Practice 39:** Use stochastic approaches for robust portfolio creation
- **Best Practice 40:** Use the models iteratively

## VI. Evaluating portfolio results and communicating transparently to regulators and stakeholders

- **Best Practice 41:** Use appropriate metrics to evaluate IRP results
- **Best Practice 42:** Report results clearly
- **Best Practice 43:** Benchmark inputs and results to other utilities
- **Best Practice 44:** Select a preferred portfolio
- **Best Practice 45:** Model state goals and priorities in preferred portfolio

## VII. Integrating the IRP process with other utility proceedings

- **Best Practice 46:** Use IRP results to inform an Action Plan and utility procurement processes
- **Best Practice 47:** Use IRP results to inform planning for bulk power systems
- **Best Practice 48:** Evaluate bill impacts
- **Best Practice 49:** Consider energy justice comprehensively
- **Best Practice 50:** Consider the evolving natural gas distribution industry

# Introduction

## What is integrated resource planning and why is it important?

An integrated resource plan (IRP) is a roadmap for meeting forecasted electricity demand over a specified future period, historically focused on the bulk power system.[1,2] Many vertically integrated utilities in the United States, including investor-owned, municipal, and rural cooperative utilities, conduct IRP processes. Regulated utilities—investor-owned as well as cooperative utilities in some states—file these plans with public utility commissions under state guidance. Other cooperative utilities and municipal utilities submit plans only to their governing boards.

The IRP process provides resource planners with a framework for evaluating plausible futures for the utility's electric system and receiving input from stakeholders and regulators. The objective of an IRP is to demonstrate which resource portfolio is most likely to be least cost in the face of risks and uncertainties. IRPs provide regulators and stakeholders with information on electric system demand, reliability, costs, risks, and uncertainties and other important issues that affect utility customers.

Robust resource planning is critical for utilities to make investment decisions that are reasonable, prudent, and in the public interest. Poor utility resource investment decisions can burden customers with electricity costs that are higher than necessary, lead to over- or under-procurement of resources, disrupt achievement of state policy goals, and forego solutions to contain costs and risks in the future. Well-planned resource investment decisions can maintain reliable, resilient electricity service and affordable utility bills for customers, while minimizing negative societal impacts and enabling transformation of the energy system to meet future needs.

IRP processes emerged from least-cost planning in the late 1980s when concerns over fuel price volatility and bulk power reliability prompted states to require electric utilities to examine prudency and affordability of investments, among other issues. A majority of states today require regulated electric utilities to file IRPs (Figure 1). Some states require utilities to file less comprehensive long-term plans. In Florida, for example, utilities must file Ten Year Site Plans every year, but these plans do not include capacity expansion or optimized portfolio modeling. In addition, some utilities file IRPs to meet requirements of federal power marketing agencies (National Archives, n.d.), and some utilities voluntarily file IRPs. While IRPs are not

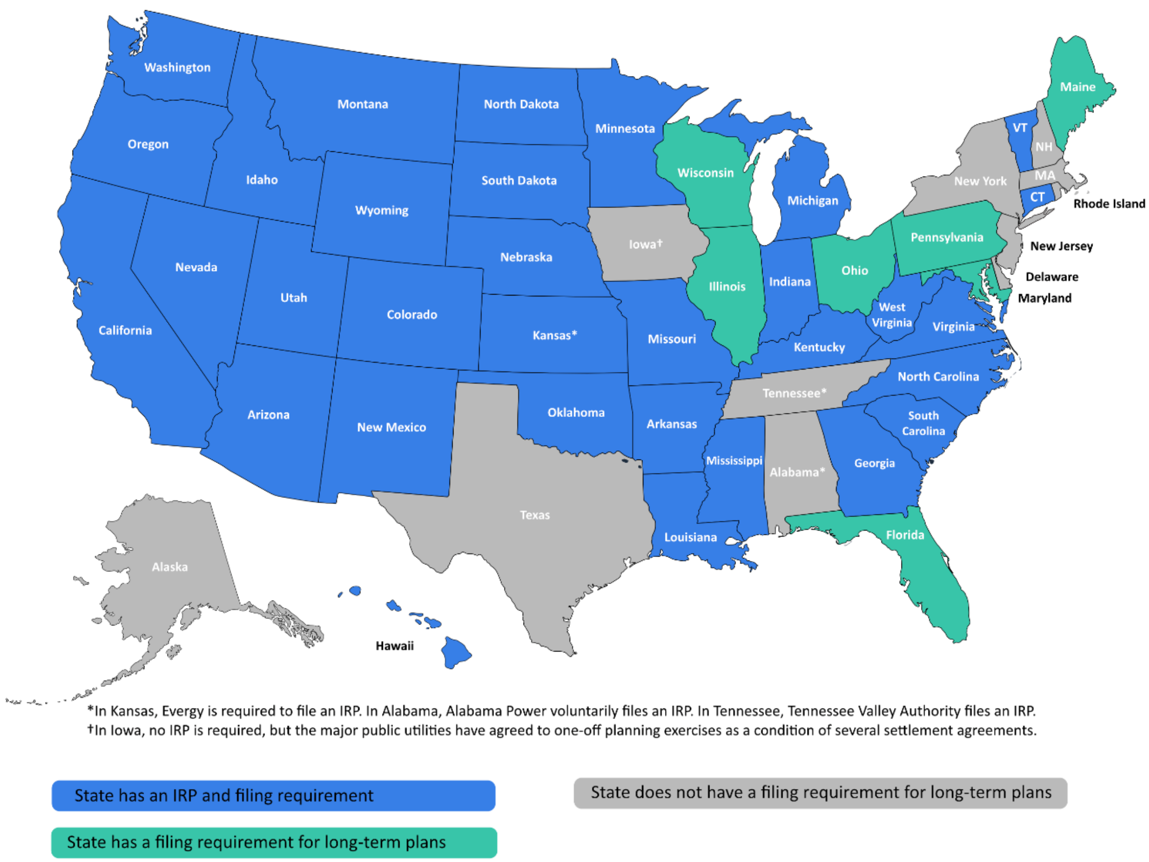
***Well-planned resource investment decisions can maintain reliable, resilient electricity service and affordable utility bills for customers while minimizing negative societal impacts and enabling transformation of the energy system to meet future needs.***

[1] Some jurisdictions are implementing or investigating Integrated System Planning approaches. For example, Hawaiian Electric filed its first Integrated Grid Plan in 2023 to harmonize distribution, transmission, and generation planning through iterative modeling. In 2023, Salt River Project in Arizona published its first Integrated System Plan. Public Service of Colorado is working to integrate modeling and planning across electric generation, transmission, and distribution, as well as natural gas. Washington state requires its large dual-fuel utility, Puget Sound Energy, to file an Integrated System Plan by 2027 (RCW 80.86.020(4)).

[2] The electricity industry often uses the term "IRP" to refer to both the resource planning process and the resulting resource plan filing. In this report, "IRP" refers to the plan and "IRP process" describes the process that results in the plan.

required in all states, lessons from quality IRP processes are applicable across all utility planning processes.

*Figure 1. States with integrated resource planning or similar processes as of November 2024*




An IRP process is also a vehicle for planning, oversight, and feedback. The basic framework is the same across most states: The utility performs modeling and analysis with input from stakeholders and communities, synthesizes the results into a written plan, and submits it to state regulators for review. Utility customers and other stakeholders have an opportunity to provide input, and the utility can move forward with a plan that is informed by stakeholder input and some amount of regulatory review and oversight. The ideal process is one that is mutually beneficial for both the utility and the public.

The rules that govern IRP processes vary by state (RMI 2023). The required filing frequency varies from 1 to 5 years. The planning horizon required for most IRPs spans 10 to 20 years, although some utilities plan out as far as 40 years. Many states require utilities to include a near-term (2 to 5 year) action plan.

Regulatory action from state commissions on IRPs varies, from accepting that the plan meets filing requirements—with any deficiencies noted (e.g., Mississippi), to acknowledging that the plan seems reasonable at the time (e.g., Oregon, Utah), to approving or rejecting the plan (e.g., Colorado, Georgia, Nevada). A commission's decision on the IRP typically carries weight in cost recovery proceedings such as general rate cases that determine the revenue the utility may collect through customers' electricity rates.

In some states, IRP and resource procurement processes are tightly coupled (e.g., Nevada, Colorado, and Minnesota); in other states, they are more distinct processes (LBNL 2021a). Procurement processes can provide current input data for use in IRP modeling. Although an IRP establishes a resource investment plan, real-world changes such as equipment failure, new regulations, and changing market trends often demand adjustments and deviations in resource procurement from what was planned.

Utilities have considerable latitude in the way that they conduct IRP modeling and present results. Further, IRP technical complexity and asymmetries of information make oversight difficult. Nevertheless, state utility regulators and stakeholders can take concrete actions to support IRPs that are consistently well conducted. Enabling such engagement requires that planning processes are transparent and inclusive, state planning objectives are explicit, and utility models and methods are up to date and rigorously applied.

## What has changed in the last decade?

Synapse authored a report on IRP best practices in 2013 (Synapse 2013). In the decade that followed, the U.S. electric power landscape changed substantially. This updated and expanded guide addresses a multitude of changes that could lead to a large buildout of the electricity system in the future. The potential for such a buildout places new urgency on the need for quality long-term resource planning. Without quality planning, we risk short-sighted and inefficient investments that impede the optimal buildout of the utility system. Thoughtful planning supports investments in electricity systems that are resilient, robust, and meet future needs.

The main drivers of change over the past decade include low natural gas prices, falling prices for renewable and other low-carbon energy resources, significant growth in variable energy resources, advances in generation and grid management technologies, increased use of distributed energy resources for grid services, increasing frequency and severity of extreme weather events, fuel price volatility, inflation and supply chain disruption, interconnection queue challenges, decarbonization goals and targets, and environmental regulations.

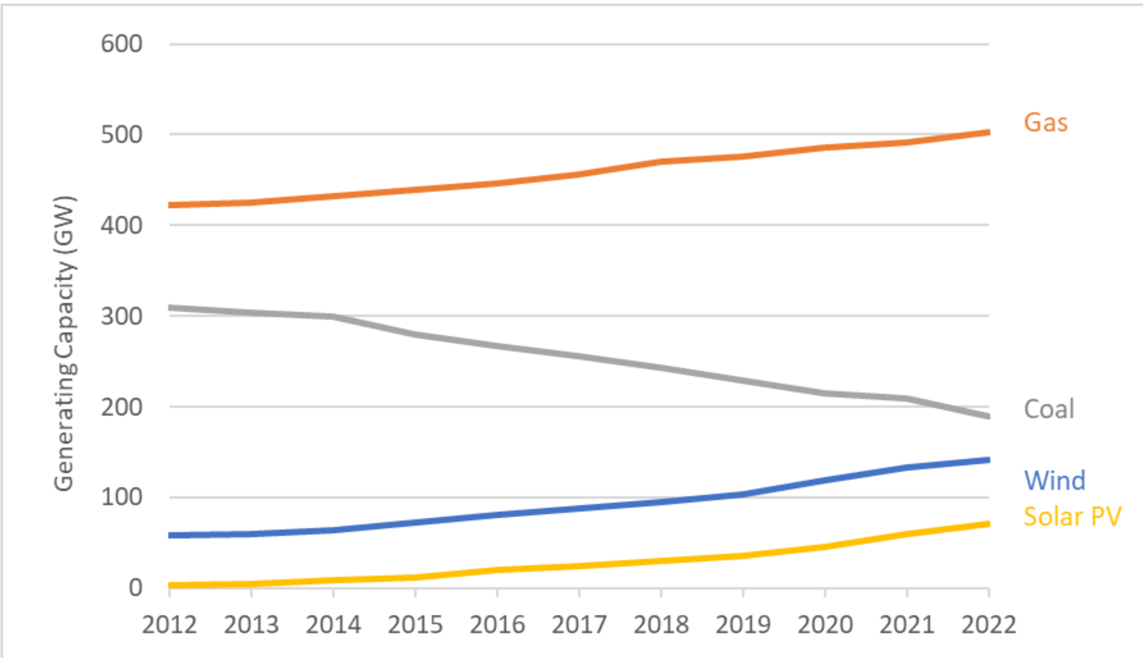
> ***Thoughtful planning supports investments in electricity systems that are resilient, robust, and meet future needs.***

Looking forward, we expect to see many of these trends continue. We also expect acceleration of current trends due to electrification of transportation and buildings, growth in data center loads and other end uses driven by artificial intelligence (AI) as well as manufacturing, retirement of coal plants and reduction of coal supply, changing capacity accreditation[3] frameworks for resources, changes in renewable energy prices, integration and interconnection challenges with increased deployment of wind and solar, and development of new carbon-free technologies. In addition, there will always be changes we cannot predict. IRPs can build in flexibility to reevaluate resource acquisition strategies over time and make resource decisions closer in time to projected needs.

[3] Capacity accreditation is the process of measuring and assigning a value to a resource that represents its contribution to resource adequacy and reliability on an electricity system. NERC defines resource adequacy in its Planning Resource Adequacy Analysis, Assessment and Documentation (BAL-502-RFC-02) as "the ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses)."

The electricity resource mix has changed dramatically since Synapse's 2013 report (Figure 2). That year, the United States was in the midst of a shale gas revolution that enabled an industry-wide move from coal to gas (U Michigan 2014). Gas, wind, and solar capacity has continued to grow over time, increasing the shift away from coal (U.S. EPA 2022). Until recently, electric utility demand was in a two-decades-long period of relatively flat load growth. In the last decade (2014–2023), electricity demand grew just 2.6 percent (U.S. EIA 2024a).

*Figure 2. Utility-scale electric generating capacity for selected resource types in the United States*




*Source: U.S. Energy Information Administration. 2024. "Sales of Electricity to Ultimate Customer: Total by End-Use Sector, 2014-March 2024," Table 5.1. https://www.eia.gov/electricity/monthly/xls/table_5_01.xlsx.*

Technology innovation also has had a significant effect on resource costs over the last decade—for example:

- New renewable energy technologies and economies of scale have reduced the cost of wind and solar precipitously. They are now often the least expensive new resources available on a per megawatt-hour (MWh) of energy basis (NREL 2021a). In 2022, renewable power generation exceeded coal generation for the first time in U.S. history, and renewable resources now produce 21 percent of annual generation (U.S. EIA 2023c).
- Utilities are deploying cost-competitive utility-scale batteries across the country to help meet peak demand, mitigate short-term changes in solar and wind supply, and provide ancillary services (Martucci 2024).
- Grid modernization advancements, such as advanced metering infrastructure paired with time-varying rates and control technologies, microgrids, and distributed generation and storage, have increased visibility into and management of end-use energy consumption, providing utility

customers with new opportunities for demand flexibility to reduce energy bills and provide grid services (Deloitte 2022).

Federal and state policies and regulations also affect the resource mix. For example, the *Inflation Reduction Act of 2022* (IRA) introduced multiple federal incentives to modernize and decarbonize the electric grid. In another example, the Federal Energy Regulatory Commission (FERC) Order 1920 is intended in part to ease access to remote, low-cost resources such as wind and solar. In addition, large utility customers in the private and government sectors are increasingly purchasing low-carbon energy resources, and many utilities are integrating corporate decarbonization goals into their planning processes (LBNL 2019a).

These advances appear against a backdrop of new challenges (EPRI 2023b):

- The interconnection queue for new resources has grown tremendously, creating a deployment bottleneck and slowing down the pace of deployment of new wind and solar resources in many regions (LBNL 2023d).
- Inflation, tariffs, and supply chain challenges stemming from the COVID-19 pandemic disrupted the steady downward trend in renewable energy costs and created a relatively short-term period of stagnation in price decline trends (LBNL 2023c).
- Extreme weather events driven by climate change, including extreme heat, severe and prolonged cold snaps, raging storms, and wildfires, have revealed the fragility of power grids and prompted new efforts by utilities to better understand resource adequacy needs to boost resilience and improve capacity accreditation methods (FERC 2023).
- A rapid rise in data center load growth driven by AI and an increase in industrial and manufacturing investments add risks for resource planning (Grid Strategies 2023). Coupled with trends in electric vehicle (EV) adoption, building electrification, and integration of planning across the bulk power and distribution systems, utilities are facing a new paradigm for planning (IEA 2024; NREL 2021b).
- Retirements of coal units are accelerating along with deployment of renewable energy, driven in part by state and federal environmental regulations and incentives (S&P Global, n.d.). This creates new challenges for reliability and grid planning and requires increased investment in transmission, firm flexible resources (such as battery storage), and grid management technologies.

Age-old challenges also continue in new contexts. For example, Americans have weathered multiple periods of fossil fuel price shocks. Most recently, the 2022 Russian invasion of Ukraine impacted gas supply and prices (Maneejuk, Kaewtathip, and Yamaka 2024). The domestic coal industry has wrestled with dwindling demand, labor challenges for mines and transportation, and constriction and consolidation of coal supply ownership (PA Consulting 2023). Such challenges highlight the importance of understanding risks associated with fuel price volatility (Amy 2023) and spending large amounts of capital to maintain aging, potentially uneconomic power assets (EIPT 2023). Another challenge is the cost of new infrastructure that may be needed for fuel delivery and storage. These issues underscore the importance of robustly evaluating the economics of retirement and replacement of legacy generating units.

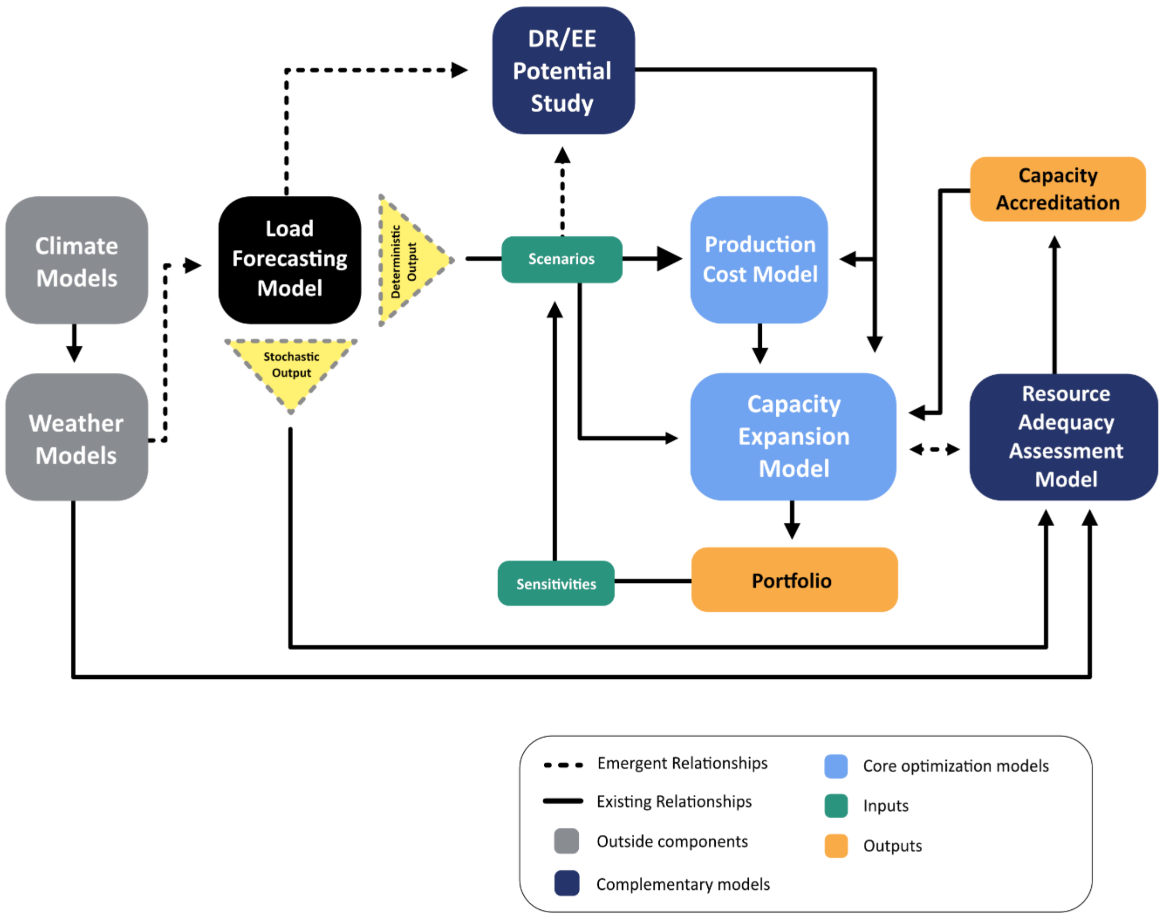
Thoughtful and robust long-term planning is needed more than ever. In this moment of rapid, widespread changes affecting both supply- and demand-side resources, the planning tools and strategies of the past do not match the scale and pace of today's needs. Emerging best planning practices can help tackle these challenges by providing a wide range of tools for navigating this transition and positioning utilities to evolve and adapt as energy systems and markets continue to change.

## The role of modeling in IRP

Modeling is a core tool of the IRP process that informs utility planning decisions. To achieve multiple planning objectives, the utility can choose the most appropriate models and run them with accurate and transparent inputs. At the same time, some input data may be sensitive to the company's confidential business strategy or financial decisions. Planners can pair modeling tools with rigorous analysis, critical thinking, and creativity, using judgment and good sense throughout the modeling process.

IRP processes use many types of models to generate different types of forecasts. Figure 3 illustrates a typical IRP modeling structure. Planners conduct separate studies when necessary to generate forecasts, which become key input parameters into other models. For example, one model may forecast fuel prices or new resource costs, which may in turn feed into models that simulate generation unit economics. Reliability modeling helps to determine the reserve margin and other reliability metrics that a utility must meet and to assess capacity accreditation for different resource types. Planners may use additional models to determine key input parameters such as potential and costs for energy efficiency and demand response resources.

*Figure 3. Example of a typical model structure used in IRP processes and current (solid line) and potential (dashed line) interdependence*




*Note: DR refers to demand response. EE refers to energy efficiency.*

Descriptions of modeling in this guide primarily focus on capacity expansion and production cost modeling, which lie at the center of the modern IRP process. These two techno-economic modeling steps are increasingly integrated and performed in an iterative manner. Integration of these models with resource adequacy assessment models is an aspirational practice to develop robust least-cost portfolios.

The capacity expansion model simulates the current system, then determines the optimal, least-cost schedule to retire, build, and run generation and storage units as well as demand-side resources. These decisions usually occur on an annual basis. This first model is called "capacity expansion" because the model can add new resources and retire existing ones. The goal of the model is to build a least-cost system that meets projected loads, subject to reliability constraints and policy requirements such as state renewable portfolio standards.

The production cost model optimizes a candidate resource portfolio for least-cost operations, capturing economic dispatch, unit commitment, ancillary service requirements, and other technical constraints at an hourly or sub-hourly basis. This simulation of the economic operation of the power system is often much more temporally and spatially detailed than simulation by the capacity expansion model.

Production cost modeling provides detailed results on system cost, operations, emissions, variable energy curtailment, and other key metrics and outputs.

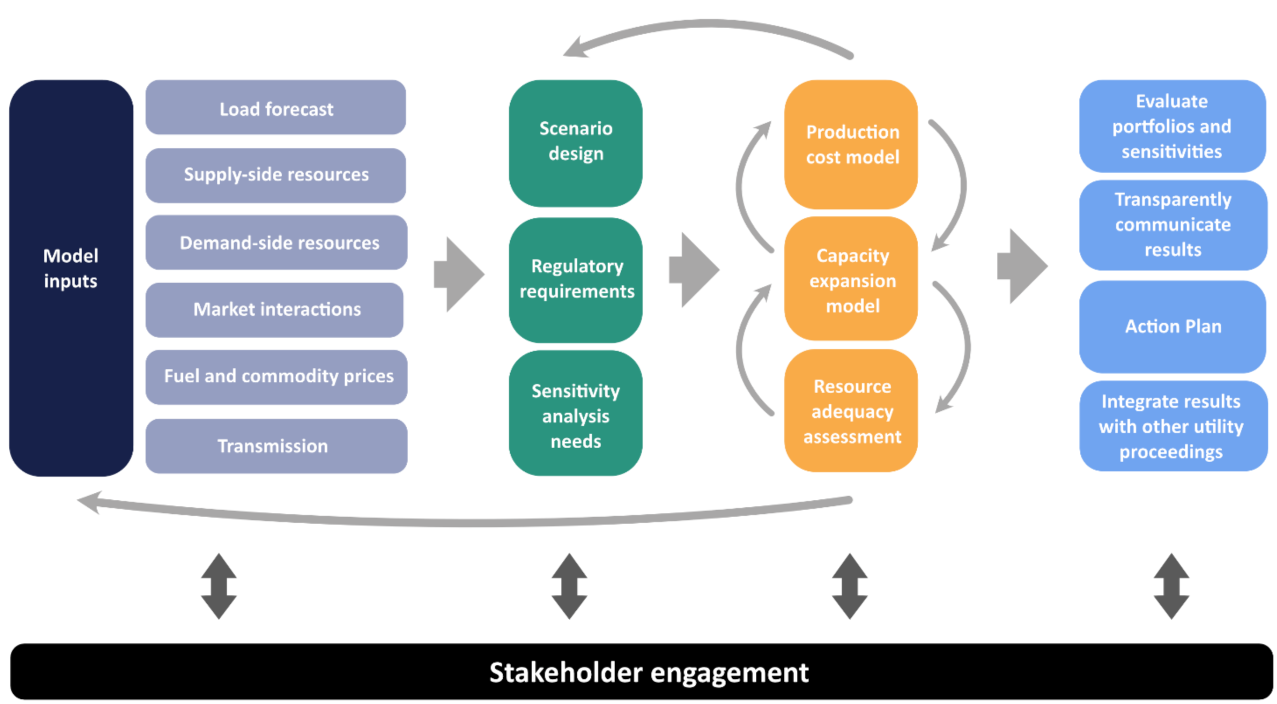
At its core, capacity expansion and production cost modeling are about minimizing system costs subject to constraints. The extent to which a modeler allows the model to optimize, and the information the modeler feeds the model for that purpose, are critical for achieving useful IRP results.

***At its core, capacity expansion and production cost modeling are about optimizing subject to constraints. The extent to which the model is allowed to optimize, and the information modelers feed the model for that purpose, are critical for achieving useful IRP modeling results.***

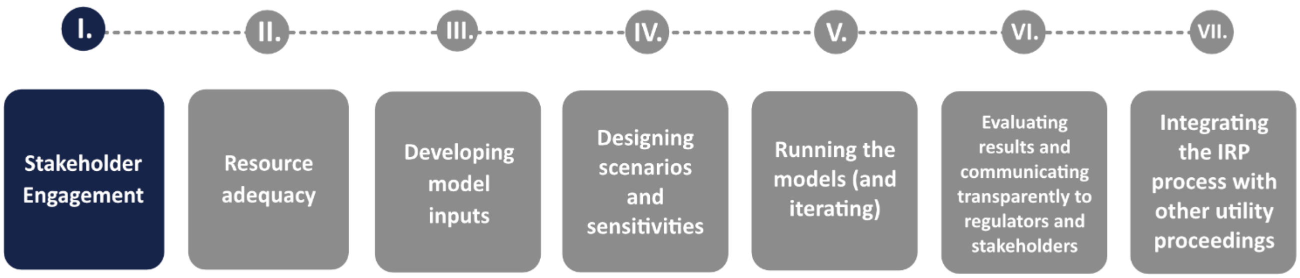
## Overview of Report

The rest of this guide describes both current and emerging best practices in IRP. The guide mirrors the order of a typical IRP process. Figure 4 depicts the typical IRP process flow, including how modeling interacts with other steps of the process, such as stakeholder engagement. The report begins by outlining the requirements for a robust stakeholder engagement process. We then summarize best practices for integrating resource adequacy into IRPs. Next, we present best practices related to developing robust model inputs, designing scenarios and sensitivities, and running the model. Then, we discuss how to evaluate and communicate portfolio results. We end with a discussion of how to integrate IRP processes with other utility planning processes and proceedings.

*Figure 4. Typical IRP process flow diagram*



# I. Stakeholder engagement




The first two best practices in this guide focus on how to engage stakeholders in the IRP process. We provide suggestions for making the process inclusive for a wide audience as well as ensuring that technical stakeholders have the tools necessary to participate in the modeling process.

## Best Practice 1. Use an inclusive stakeholder process

*Develop an inclusive stakeholder engagement process that balances access and transparency with reasonable time commitments.*

Vertically integrated electric utilities provide essential energy and delivery services to a captive customer base through a monopoly business model, while operating in a highly technical and complex field. To ensure that utility decisions are fair and robust and based on reasonable evidence, meaningful stakeholder engagement (RMI 2023), regulatory oversight, and participation of technical experts working on behalf of stakeholders are essential in the IRP development process. A well-developed stakeholder engagement process provides access to all stakeholders who have a reasonable interest and stake in the utility decision-making process— including those who have traditionally been underrepresented in these processes.

An effective IRP process includes regular stakeholder meetings that allow participation and engagement throughout the IRP process, from input development through scenario development and modeling, review of results, selection of the preferred portfolio, and development of the action plan. The utility engages stakeholders early in the process, on a timeline and in a manner that allows for meaningful feedback. The following elements represent a set of minimum practices for an effective stakeholder engagement process:

**Process and design elements**

- The utility develops a charter or document clearly outlining the rules, norms, and any other relevant details for the stakeholder engagement process, with buy-in from stakeholders to align expectations for all parties.
- Facilitators, technical consultants, or an internal communications team moderate stakeholder sessions and technical conferences.

- Materials, including an agenda and slides to be presented, are available in advance of each stakeholder meeting and technical conference so stakeholders have time to review the information, prepare for planned topics, and provide productive input.
- A formal discovery process allows stakeholders access to data, assumptions, results, and any other information that the utility does not directly offer.
- The process elicits stakeholder feedback during stakeholder meetings and technical conferences, as well as through a formal commenting process, with clear deadlines for providing input.
- Utilities provide formal responses to stakeholder feedback, adhering to clear deadlines for responding to stakeholder comments. Responses clearly address which feedback is being adopted and how, and which is not and why.

**Removing barriers to participation**

- Stakeholder sessions accommodate remote access to enable as many stakeholders as possible to participate, including members of the public and underrepresented groups.
- The stakeholder process design considers and accommodates stakeholders' needs and challenges such as language, schedules, and economic barriers.
- Technical education sessions, offered and open to all, provide core education on the IRP process (as needed/requested by stakeholders).
- Stakeholder sessions occur regularly enough to allow for meaningful input and participation throughout the development of the IRP, without being so time-intensive and burdensome that only a handful of people can fully participate.
- Intervenor compensation funds designate and otherwise approve stakeholders to formally participate in public utility commission (PUC) proceedings, addressing barriers to participation and engagement of technical experts for many stakeholders. Such funding typically requires action by state legislatures and utility regulators.

**Transparency**

- The IRP process engages stakeholders throughout, including:
    - Before modeling begins to propose scenarios and inputs and provide feedback on what is being modeled and how;
    - During modeling to provide input on results; and
    - After the draft plan is released to provide input on how the utility used the results to create an action plan.
- Transparency is a priority, with the utility sharing all input data, modeling assumptions, scenario and sensitivity designs,[4] modeling files, and modeling results as they become available–as well as any other information necessary for stakeholders to have a comprehensive understanding of how the IRP was developed. This may include sharing utility spreadsheets used for pre-

[4] As discussed in Section VI, a scenario is a model run with a specific set of input assumptions and constraints. A sensitivity changes a single key input to understand how that input affects or drives results, often across multiple scenarios.

processing of data and post-processing of results so stakeholders can see how the utility used both input and outputs.

- The utility shares data, inputs, and results for its preferred portfolio and all major scenarios and sensitivities–not just for one base scenario.[5]
- The utility only requires non-disclosure agreements (NDA) when necessary to protect data that is truly a utility trade secret or that the utility holds under a third-party NDA (e.g., fuel and market price forecasts) to avoid unnecessarily hindering stakeholder engagement.[6]

**Technical engagement**

- The process allows stakeholder-funded technical experts to participate and contribute essential technical expertise.
- The process includes technical IRP sessions, open to all stakeholders, to allow for additional expert input on specific topics, beyond what may be provided in public meetings.
- Technical experts have access to review all inputs, outputs, modeling files and can gain access to the modeling software the utilities used (as discussed in Best Practice 2).

If utilities are unable to meet any of these elements, they can make appropriate efforts to retroactively ensure stakeholders have an opportunity to give productive input.

There are many examples of public utility commissions and utilities implementing the practices noted above. For instance, in 2022 the New Mexico Public Regulation Commission established new rules that promote engagement and transparency in IRP processes for the state's investor-owned electric utilities. The rules require the utilities to use a facilitated stakeholder process and provide stakeholders with reasonable access to modeling software, perform a reasonable number of modeling runs, and share all modeling information (Gridworks 2024).

As another example, in 2018 the Hawaii Public Utilities Commission ordered Hawaiian Electric Companies to develop a workplan that comprehensively describes the timing and scope of major activities that will occur in the integrated grid planning (IGP) process (HI PUC 2018). The workplan describes the following: (1) the proposed working groups, including specific objectives, composition, expected deliverables, and timelines; (2) a proposal for how forecasting assumptions, system data, modeling inputs, studies, analyses, meeting summaries, and other data will be shared with the PUC and community members throughout the IGP process; (3) processes and timelines to define and quantify system needs; (4) processes and timelines to procure solutions to meet grid needs and to optimize the solutions; (5) opportunities for midstream evaluation and updates; and (6) the role of independent facilitation in assisting the IGP process.

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[5] As discussed in Section VI, a utility identifies a preferred portfolio after reviewing the results of the modeling analysis. This collection of resource builds and retirements reflects the utility's short- and long-term resource plans.
[6] IRPs provide a framework to inform utility resource solicitations and specific resource commitments. Overuse of protective agreements and redactions in an IRP can hinder stakeholder engagement in those processes.

## Best Practice 2. Engage technical stakeholders in IRP modeling

*Provide modeling files and other necessary information to technical stakeholders to allow them to replicate modeling outcomes from the IRP and develop alternative portfolios.*

Utility IRP modeling is generally conducted using sophisticated and proprietary capacity expansion and production cost modeling software. The software is largely inaccessible to stakeholders, challenging their role in supporting regulatory oversight. Often, PUC staff are not trained in utility modeling software, so they cannot ensure that utilities conducted modeling reasonably and prudently. However, technical stakeholders with modeling expertise and access to data can verify and validate utility outcomes and findings. They can independently test utility assumptions, identify refinements and improvements, and bring additional technical knowledge to IRP proceedings. Such contributions by stakeholders are valuable even in states where PUC staff are more engaged in IRP modeling. Stakeholders can also model alternative portfolios that use the same, or a similar, modeling framework as the utility. The commission would not have such information in the absence of technical intervenor participation.

The following is necessary to enable technical intervenors to participate in the modeling process:

- Modeling software licenses, paid for by the utility, for all technically sophisticated stakeholders with the ability to review the modeling files or perform their own modeling runs
- Input data, model settings and constraints, and output data for the reference portfolio and preferred portfolio as well as all major scenarios presented in the IRP
- Modeling files and data that match what the utility is using so that intervenors are able to replicate the utility's modeling outcomes as a starting point and calibration step for their own modeling exercises
- Explanations of how the utility used input data and values, how it derived inputs, and what steps the utility took to develop portfolios and results
- Utility spreadsheets used for pre-processing of data and post-processing of results so stakeholders can see any modifications used to develop model input streams and convert outputs to revenue requirement results
- Documentation for supplemental analysis the utility used to develop inputs, such as reserve margin or effective load-carrying capability (ELCC), that it developed externally or outside the model.

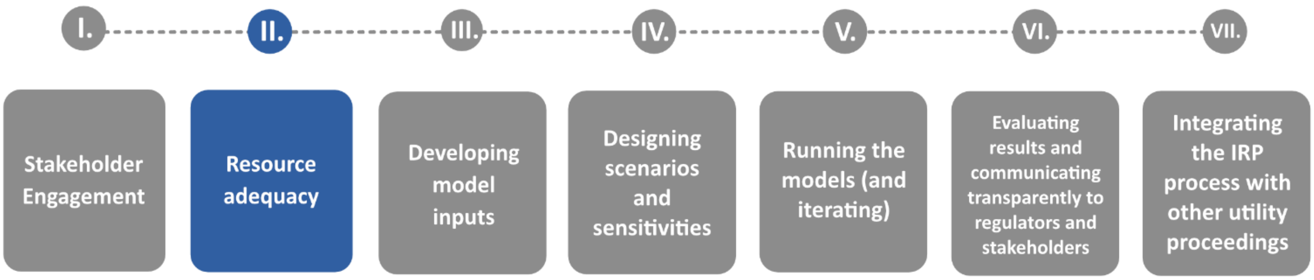
### Definition: Effective load carrying capability

The ELCC of a resource or portfolio of resources represents the amount of dependable capacity the resource can provide.

For example, as part of the Arizona Public Service (APS) 2023 IRP process, the commission required the utility to provide intervenors with licenses for the Aurora model, utility modeling files, and trainings with the model developer as well as access to resources (ACC 2022). This allowed stakeholders to carry out their own modeling.[7] In Iowa, as part of two settlement agreements, MidAmerican Energy Company and Interstate Power and Light agreed to provide intervenors with model licenses as part of the Renewable Energy Study docket (MEC 2022). In Michigan, DTE and Consumers Energy also agreed voluntarily to provide modeling licenses to stakeholders as part of the IRP process.

[7] However, the utility did not provide the modeling files for all of its scenarios, limiting stakeholders' ability to validate the company's modeling results for its preferred portfolio and scenarios.

# II. Resource adequacy




IRP capacity expansion models are designed to optimize resource build and retirement decisions while maintaining an acceptable level of system reliability and meeting policy requirements. These models typically represent system reliability using a planning reserve margin, which denotes the energy capacity in excess of the forecasted peak load that the utility needs to serve in order to maintain the desired level of reliability. The required reserve margin creates a buffer to protect the system from load forecasting uncertainty and factors that could unexpectedly influence supply or demand. Such factors include unplanned unit outages, generation or transmission contingencies affecting energy supply, and extreme weather events.

Traditionally, resource planners used an annual planning reserve margin and designed their systems to ensure that they could meet demand on the single annual hour of peak demand. Planners would calculate the annual planning reserve margin necessary to achieve target levels of system outages and calculate a firm capacity rating for each resource based on its expected availability at peak. Then, they would run their capacity expansion model to optimize resource build and retirement decisions based on the annual planning reserve margin constraints. There was limited iteration.

This construct worked relatively well when resource availability[8] was relatively uniform year-round,[9] nearly all system resources were dispatchable, and peak demand was substantially larger during one season. But planners can no longer universally assume any of these things to be true, particularly as renewable energy sources and storage make up a larger portion of the resource mix. Planning for times with low resource availability can be as important as planning for times with peak system demand. This planning is most effectively done by evaluating system needs and resource contributions through a coordinated and iterative resource adequacy assessment.

Resource adequacy is defined by Electric Power Research Institute (EPRI) as an assessment of whether the current, or projected, resource mix is sufficient to meet capacity and energy needs for a particular grid (EPRI n.d.). Validation of resource adequacy is a critical and integral part of resource planning. Ultimately, best practices in resource adequacy are not about developing robust static metrics, but rather developing an iterative process for establishing system need, valuing resource contribution to system

[8] Here we refer to resource availability generally as the megawatts (MW) of capacity a resource can provide to the grid based on its own inherent characteristics and limitations, as well as external conditions that impact operations.
[9] With small deviations for steam unit performance based on temperature.

need, and testing how well a resulting portfolio meets system needs. However, in the absence of an iterative modeling process, development of a robust reserve margin is essential.

This section of the report introduces foundational best practices for addressing resource adequacy in IRPs. Recognizing the complexity of the issue, the variety of approaches available, and work by many others in the field, we recommend that resource planners use our best practices as a baseline and screen. Figure 5 provides resources (linked) developed by Energy Systems Integration Group (ESIG), EPRI, and other leading experts in the field that offer more detailed discussion on resource adequacy principles and specific implementation guidance.

*Figure 5. Resources on resource adequacy principles and specific implementation guidance—click to view*

- Linking Capacity Expansion, Resource Adequacy, and Production Cost Modeling Tools for Integrated Strategic System Planning. (Electric Power Research Institute 2024)
- Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation. (Energy Systems Integration Group 2023)
- New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements. (Energy Systems Integration Group 2024)
- Redefining Resource Adequacy for Modern Power Systems. A Report of the Redefining Resource Adequacy Task Force. (Energy Systems Integration Group 2021)
- Lawrence Berkeley National Laboratory: A Guide for Improved Resource Adequacy Assessments in Evolving Power Systems. (Carvallo et al. 2023)

We discuss three best practices in this guide related to resource adequacy: (1) integrating resource adequacy analysis, resource planning analysis, and development of robust reserve margins; (2) aligning resource accreditation with realistic expectations of resource availability and applying constructs uniformly across resource types; and (3) taking a regional perspective on resource adequacy.

### Looking Ahead: Link frameworks for developing reserve margins and resource capacity accreditation

Looking to the future, the framework for developing the reserve margin and the framework for calculating resource capacity accreditation need to evolve together, as the two are inherently linked.

## Best Practice 3. Link resource adequacy assessments with resource planning

*Conduct resource adequacy assessments and resource planning analysis in a coordinated and iterative manner.*

Linking resource adequacy assessments with resource planning in an iterative manner generally starts with stochastic modeling[10] to develop a reserve margin that reflects reliability standards and requirements and preferences.[11] Planners then use the reserve margin in the resource planning model to develop an optimized resource plan. The resulting resource plan is then tested in the resource adequacy model to ensure that the plan still meets system reliability requirements, or that it does not exceed them significantly (since overly adequate systems have higher cost). Iterations continue on the reserve margin and resource portfolio until the modeling develops an optimized resource plan that meets the reliability standard. In practice, it is not essential to develop a precise reserve margin when resource adequacy modeling is being used to validate portfolio performance. In such cases, utilities can choose a reasonable starting value and iterate as necessary.

In PNM's 2020 IRP, for example, the utility used SERVM to develop the planning reserve margin requirement needed to meet a loss-of-load expectation (LOLE) standard of 0.2 days per year as well as to validate that the IRP portfolios met or exceeded this resource adequacy standard (E3 and Astrape 2022). While this type of iterative modeling is the best practice, it is time- and resource-intensive. For IRP processes that do not use resource adequacy modeling to validate portfolio performance, development of a robust reserve margin upfront is essential.

Planners typically calculate reserve margins and other resource adequacy metrics through separate modeling exercises conducted prior to IRP modeling. Utilities operating outside of centrally organized wholesale electricity markets are responsible for calculating their own resource adequacy metrics. In regions with organized regional transmission operator (RTO) or independent system operator (ISO) markets, the grid operator generally conducts extensive resource adequacy analysis, and utilities adopt the RTO or ISO values rather than conduct their own analysis. In the Midcontinent Independent System Operator (MISO) market, for example, the market operator released a seasonal capacity accreditation framework applicable to all utilities within the market. Utilities such as Ameren Missouri internalize MISO's planning reserve margin (Ameren Missouri 2023b).

Critically, planning reserve margin and capacity accreditation frameworks need synchronization. If the utility is using a reserve margin differentiated by season, it must also value the capacity accreditation of resources differently by season. Calculations of capacity accreditation values for individual resources occur through similar, but separate, resource adequacy analysis (as discussed in detail in the next section). The framework for developing the planning reserve margin and the framework for calculating resource capacity accreditation ultimately need to evolve together, as the two are inherently linked.

[10] Stochastic modeling accounts for uncertainty by performing a range of simulated futures and accounting for the probability of that future occurring.

[11] Reserve margins are developed to achieve a reliability benchmark, such as a maximum number of expected hours with outages per year (e.g., a 1-day-in-10-years loss of load expectation).

Planners conduct reliability analysis using stochastic techniques coupled with Monte Carlo analysis[12] to determine how a given reserve margin, portfolio, or resource meets reliability requirements. Stochastic analysis relies on large quantities of weather data that contains both normal and extreme weather events to test performance under a wide range of circumstances. Typically, planners use historical data, although some utilities are switching to use climate change forecast data instead.[13] There are limitations for planners to consider when using historical data for calibration and characterizing stress events, due to increased frequency and severity of extreme weather events as well as accelerating electrification, manufacturing, and data center loads—which may not be reflected in historical load. Forward-looking, synthetic data also has limitations, mainly related to availability and judging its veracity. An example of a utility that has conducted a separate, stochastic modeling study to develop a planning reserve margin and assess resource adequacy is Public Service Company of Colorado (Astrapé Consulting 2021).

Resource adequacy analysis can test variations in a discrete number of factors such as load and outage rates. Modeling runs typically focus on a single study year at a time and identify the time periods with the highest LOLE. The resulting hundreds to thousands of iterations for each study year determine the likely performance of an entire system with a given portfolio. The required planning reserve margin may differ by year based on the available capacity mix from utility-owned and -procured resources, as well as from the market, and the outage rates of capacity resources for that given year, for example. Because a utility conducts resource adequacy analysis for a single study year, when it is validating the resource adequacy performance of a portfolio, it would ideally repeat the modeling for years in which the utility expects large changes in the system. Some utilities perform the additional step of evaluating the cost to the system of different reserve margin levels above the minimum required to achieve the reliability target (such as the 1-in-10-year LOLE). For example, Georgia Power included an economic and reliability study of the target reserve margin as part of its 2022 IRP filing (GPC 2022).

## Best Practice 4. Apply consistent accreditation frameworks to all resource types

*Credit all resource types in a fair and consistent manner, and clearly align reliability modeling with realistic expectations of resource availability.*

The current best practice for capacity accreditation is to use stochastic modeling to conduct an ELCC study for each resource type. A consistent methodology to accredit resources can ensure all resource types are treated in a fair and non-discriminatory manner. The ELCC of a resource represents the amount of incremental dependable capacity the resource can provide to the system. The first step is evaluating how much additional load can be served on the utility system with the addition of a set quantity of a specific resource type, while maintaining the same level of reliability. Planners then calculate the ELCC by dividing incremental peak load served by the nameplate capacity of the added resource. The result is a marginal ELCC which reflects the incremental capacity contribution of the next megawatt of a given resource and an average ELCC which measures the aggregate or portfolio reliability impact of the

[12] Monte Carlo is an analysis technique used to predict the probability of different possible outcomes in the face of uncertainty. The analysis uses historical data to predict a range of future outcomes.
[13] Historical data is likely still the best source for calibration purposes, but it is important to be aware of its limitations.

resource across all megawatts (not just the next megawatt) or across a specific tranche of capacity. ELCC studies are complex, data- and time-intensive, and resource-specific. As discussed above, many RTOs and ISOs conduct their own ELCC studies which utilities can, and sometimes even must, apply to their own footprints (LBNL 2021b). Utilities that do not operate in RTO/ISO regions generally perform ELCC analysis in a modeling exercise separate from the IRP process.

Some utilities do not have time or resources to conduct their own studies for every resource considered. It is critical to avoid over-simplified assumptions that systematically disadvantage certain resource types. For example, if the utility performs a study of the ELCC for a 4-hour battery energy storage system, it cannot assume that the ELCC for an 8-hour system would be the same. Instead, the utility can look to studies from regionally comparable utilities and rely on their calculations, with reasonable and well-justified and documented adjustments as necessary, to account for differences across the utilities.

***It is critical for utilities to avoid over-simplified assumptions that systematically disadvantage certain resource types.***

Over the past decade, there has been considerable attention on calculating the ELCC for wind and solar and battery energy storage systems (BESS). There has been more limited attention on whether the traditional methods still used to value firm capacity for conventional thermal resources (such as coal, gas, or oil) — the Equivalent Forced Outage Rate Demand, or EFORd, methodologies — still result in sufficient resource adequacy. As the grid evolves, these traditional methods will not be sufficient.

EFORd-based methodologies value a resource's capacity based on the unit's historical outage rates at times it was needed. This means that modeling of fossil fuel resources usually uses average forced outage rates rather than weather-dependent forced outage rates, underrepresenting outage risk in periods of extreme weather. Recent high-profile extreme weather events, including Winter Storm Uri in 2021 and Winter Storm Elliott in 2022, highlight the risks of availability of traditional fossil fuel resources and correlated outages within a given power class of assets (e.g., natural gas) not captured by traditional capacity accreditation methodologies (S. Murphy, Sowell, and Apt 2019). These traditional methodologies (generally determined by RTOs) systematically undercount and understate the risks of unplanned outages at thermal resources by as much as 20 percent by failing to account for outage variability, correlated outages, weather-dependent outages, and fuel supply constraints (AEE 2022; Astrapé Consulting 2022).

When viewed together, the use of the EFORd method for thermal resources and ELCC method for wind and solar is concerning:

- The EFORd methodology over-accredits capacity value for thermal resources.
- Utility customers are therefore paying for some level of capacity and reliability services from thermal resources that they do not actually provide.
- Wind and solar resources are being held to a higher standard with the ELCC methodology, resulting in systematic discrimination against them.

***Traditional capacity accreditation methodologies have been found to systematically undercount and understate the risks of unplanned outages at thermal resources by as much as 20 percent.***

As discussed above, the best practice is to apply the same accreditation methodology to all resources. In this case, that is using the ELCC methodology to calculate firm capacity for all resources, including thermal resources. PJM, the ISO/RTO for the mid-Atlantic region, is following that principle.

If ELCC analysis is not available, an alternative is to develop downward adjustments to EFORd-based capacity ratings using actual unit performance during historical scarcity hours. These adjustments can account for undercounted outage risks, including fuel supply contracts, unit age, and extreme weather risks. Additionally, utilities (and ISO/RTOs) can develop and implement weather-sensitive failure rates that allow for highly correlated asset failures due to fuel availability. Using more accurate thermal capacity accreditation increases system resource adequacy by realigning incentives for utilities to improve the outage rates of thermal resources while addressing the systematic disadvantage faced by wind and solar resources.

## Best Practice 5. Use a regional perspective to plan for resource adequacy

*Align resource adequacy and resource planning with the larger region and market, when applicable, to more accurately capture regional interactions and impacts.*

Resource adequacy planning requires a regional perspective to ensure requirements are sufficient without being overly conservative and unnecessarily costly. Utilities that operate within regional markets generally align their reserve margin construct and resource accreditation framework with methods used by the market operators. For utilities not in an RTO, the best option is using resource adequacy studies for the larger region in which the utility operates (e.g., Puget Sound Energy and PNM). Modeling a utility footprint as an island may simplify the modeling exercise, but it is an overly conservative approach that undermines the resource adequacy and portfolio contributions of market transactions (LBNL 2019b) and regional resource diversity.

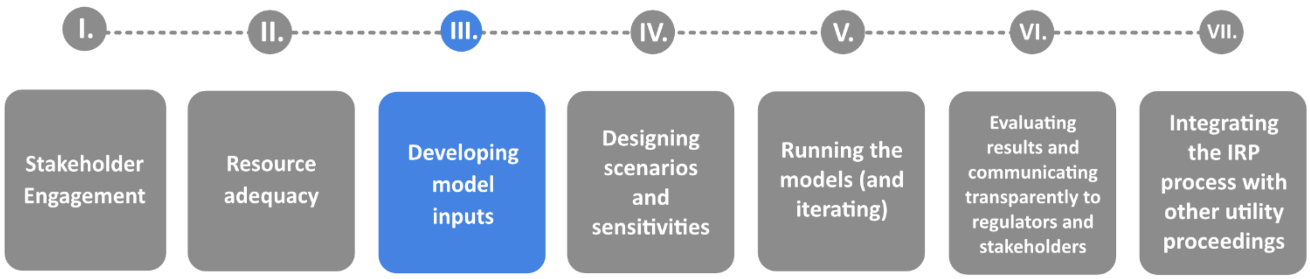
Utilities operating outside RTO/ISO regions, such as those that operate in the Southeast and Western United States, can capture regional benefits by modeling their utility footprint within the larger region in which they operate. This can include reasonable assumptions around the role of market transactions (energy and capacity) based on a realistic view of current procurement in the near term (i.e., how much the utility currently relies on the market) and likely future resource availability later in the study period. To capture the reliability impacts of resource diversity–for example, to understand how wind resources in the larger region can complement solar within the utility footprint–the utility needs up-to-date data on resource plans for other regional utilities. To address uncertainty in both market availability and regional resource development, a best practice is for utilities to model multiple future scenarios that capture different levels of future regional cooperation and resource deployment.

For utilities that operate within an RTO or ISO, market operators conduct resource adequacy evaluations that are inherently regional in scope. Market operators have a variety of unique approaches to address resource adequacy:

- After several years of development, MISO adopted a four-season capacity accreditation construct that breaks down system capacity needs into four time periods during the year.
- PJM recently proposed, and FERC approved, an overhaul of its capacity market. This change increases the accuracy of PJM's accreditation frameworks through the use of marginal ELCC calculations for all resources (new and existing, fossil fuel and renewable), providing greater confidence in reserve margin calculations (FERC ER24-99 n.d.).
- In California, three agencies—the California Public Utilities Commission (CPUC), California Independent System Operator (CAISO), and California Energy Commission—have developed a collaborative institutional relationship to ensure that utility-scale resource planning aligns with regional assumptions. CPUC requires load-serving entities such as utilities with loads greater than 700 gigawatt-hours (GWh) to perform IRP processes that adhere to resource adequacy requirements at the state (and ISO/RTO) level. CPUC then reviews the portfolios of each load-serving entity and develops a statewide IRP and preferred portfolio, which is a key input into CAISO's regional transmission planning and regional reliability modeling (CPUC 2016).
- Utilities outside California operating in the Western Interconnect do not have an ISO or RTO. The utilities individually develop reserve margins based on their own analysis of what they need to meet LOLE. The Western Electricity Coordinating Council (WECC) conducts resource adequacy assessments (WECC n.d.) to help these utilities better understand their regional resource adequacy position. Also, many entities in the Western Interconnect are participating in the development of the Western Resource Adequacy Program (WRAP), which assigns planning reserve margins to participants based on regional resource adequacy needs.[14] Additionally, the Southwest Power Pool is pursuing options to expand full regional transmission services to some utilities in the Western Interconnect, and a stakeholder initiative is underway to evaluate what governance and programmatic changes could promote future expansion of CAISO.

[14] WRAP is developing a regional reliability planning and compliance program for Western states to assess and address resource adequacy (Western Powerpool 2023).

# III. Developing model inputs




After selecting the appropriate modeling tools and evaluating reliability constraints, planners develop other critical model inputs. Developing input assumptions is ideally an iterative process as subsequent steps of the IRP process reveal new information or guidance. The following best practices guide planners through the various input assumptions, such as load forecasts, demand-side and supply-side resources, and transmission.

Best Practice 6 and Best Practice 7 provide general guidance on developing model inputs. Best Practice 8 through Best Practice 11 discuss load inputs and how to model the changing nature of electric sector demand. Best Practice 12 through Best Practice 18 discuss a wide array of practices and issues associated with supply-side resource modeling. Best Practice 19 through Best Practice 22 discuss how to incorporate energy efficiency and other demand-side resources in IRP modeling. Best Practice 23 provides guidance on modeling market purchases. Best Practice 24 and Best Practice 25 discuss fuel and commodity inputs. Best Practice 26 and Best Practice 27 address transmission modeling inputs.

## Best Practice 6. Use up-to-date inputs and assumptions

*Use inputs that reflect the most recent available knowledge, grounded in the most recent available historical data and utility-specific studies.*

Best practice is to use inputs that reflect the most recent available knowledge, without over-relying on emerging trends that can distort inputs. The typical frequency of IRP filings every 2 to 4 years requires balancing up-to-date inputs with minimizing risks from overstating near-term trends.

A key challenge to using up-to-date inputs and assumptions is planning variables that change while the IRP is under development and forecasts have already been produced and potentially implemented. Rather than continue to rely on a forecast that is directionally wrong (and depending on the stage of the IRP process), an effective IRP process develops a new forecast, waits for development of a new external forecast, or runs a sensitivity analysis using an existing forecast that best represents the current situation. Utilities are not expected to update their models during the IRP process every time something changes. If they did, they would never finish the exercise. Instead, utilities can acknowledge when a change (e.g., commodity or electricity market prices) is significant enough to render modeling results less applicable. If the utility is already too far into the planning process to update base assumptions, best practice is to add sensitivities or scenarios to capture the change (see Best Practice 28 through Best

Practice 30). When significant changes occur, the relative cost of performing additional IRP modeling is minute compared to the scale of investments informed by additional modeling. For example, if an unexpected market condition would lead to reduced natural gas supply and increase in prices, a high short- to medium-term natural gas price sensitivity would be a good option.

Utilities following best practices carefully avoid extrapolating short-term trends over a longer-term period where such assumptions are unsupported. For example, recent supply chain and inflationary pressures resulting from the COVID-19 pandemic caused prices of renewable energy and battery technologies to increase, interrupting a decade of price declines. Some industry sources project this will be a short-term trend and prices will return to previous declining trends (NREL ATB 2024). Yet some utilities have applied this current situation to adopt overly conservative cost decline assumptions for new resources for the entire 10- to 20-year IRP study period (Entergy Arkansas 2024). Adopting conservative cost decline assumptions for all resource types biases modeling results against renewable energy resources, which still are expected to experience technological advances and cost declines relative to more established, conventional technologies. This example illustrates the importance of grounding all assumptions in industry trends and real-world data. When circumstances change, best practice is to add new sensitivities or scenarios to capture the change.

In contrast to temporary price distortions due the recent pandemic, the passage of the IRA provides lasting opportunities that most utilities are just beginning to incorporate into IRPs. According to RMI, of the 50 utilities that filed planning documents between the passage of the IRA and January 2024, "32 percent failed to include IRA provisions in their models, and none adequately considered the IRA's benefits and implications for their systems" (RMI 2024b). It has taken time for the Internal Revenue Service to offer guidance on implementation of many aspects of the IRA, and guidance is still being released (U.S. IRS n.d.). However, many aspects of the IRA that affect fundamental inputs to IRP are now clear and can be internalized in IRP modeling. These include extended and expanded investment and production tax credits for zero-carbon resources and storage, tax credit adders for domestic content and project locations in energy communities,[15] and tax credits for clean hydrogen and carbon capture and storage (CCS).

A final element of this best practice is the treatment of input data that relies on historical records, such as weather data, to train weather-sensitive models or to run resource adequacy assessments. For example, in its 2021 Northwest Power Plan, the Northwest Power and Conservation Council states that the historical weather record does not reflect future weather patterns induced by a changing climate (Northwest Council 2022). The plan implements modeled climate change projections that complement historical data, giving more weight to recent years in the historical record without disregarding the historical variability of weather patterns. PJM's 2023 effort to reform resource accreditation of its capacity market provides another example. PJM explained that its preference was to extend the historical weather data used to calculate gas unit ELCC to between 30 and 50 years, and to use unit operational data from 2012 to the present(PJM Proposal 2023a; Update 2023c; PJM FERC 2023b). PJM

[15] U.S. DOE defines energy communities as (1) brownfield sites, (2) certain metropolitan statistical areas and non-metropolitan statistical areas based on unemployment rates (MSA/non-MSA), or (3) census tracts where a coal mine closed after 1999 or where a coal-fired electric generating unit was retired after 2009 (and directly adjoining census tracts). See https://www.irs.gov/pub/irs-drop/n-24-30.pdf.

also addressed the potential to include climate change adjustments to the historical weather data, as the Northwest Power and Conservation Council is doing.

## Best Practice 7. Recognize historical data limitations

*Evaluate when the past is a good predictor of the future and when the future is likely to be fundamentally different.*

Historical data is useful for calibrating model inputs and sense-checking model results, yet it does not always reflect the future. An emerging example includes observed weather data that is no longer a good predictor of the future due to climate-change-induced patterns and anomalies (see Best Practice 6). Similarly, emerging changes in load composition due to new types of loads, and substitution of fuels for electricity, render load forecasts based on historical data less accurate (see Best Practice 8). Finally, historical generator performance and outage probabilities may not reflect future conditions if units are retrofitted with equipment that improves their resilience.

There are several alternatives to historical data for developing data inputs, as in Best Practice 8 on load forecasting. However, in some cases the use of historical data is needed because it is challenging to produce credible synthetic data or because the data is used in probabilistic analyses such as resource adequacy assessments that require a high volume of actual observations. In these cases, planners can ensure they prioritize the use of more recent data over older data, or conversely reduce the weight of older data that may not reflect current conditions.

A best practice to assess the usefulness of historical data is to perform retrospective analyses of key assumptions, inputs, and forecasts. In its 2021 IRP, Puget Sound Energy devoted an entire section to performing retrospective analysis of previous demand forecasts (PSE 2021). The analysis compares forecasts developed in five previous plans—going back over a decade—with realized values for the forecast variable, adjusting for weather realizations when appropriate (e.g., for the peak demand). The utility developed analyses for electric and natural gas peak demand, housing, and population growth and provided reasons for forecast deviations that could be incorporated in current forecasts. Planners can use this retrospective analysis to inform which historical data is useful on its own, adjustments needed to historical data, or whether historical data does not sufficiently inform future system performance.

### LOAD INPUTS

## Best Practice 8. Develop a load forecast for the expected future

*Develop a load forecast that captures granular temporal and geographic detail, expected future electrification and load growth levels, and decarbonization policies—and that is aligned with current reliability modeling.*

Load forecasting is a cornerstone of IRP and one of the key model inputs for production cost, capacity expansion, and reliability models. Electrification of end uses, data center development, and other emerging trends indicate that the era of flat electric load growth is over (Grid Strategies 2023). This section covers best practice in methods, granularity, and characterization of load and its flexibility, considering these trends.

In the past, utilities forecasted annual system-level energy consumption and peak demand, generally split out by customer segment (i.e., residential, commercial, industrial). System operational challenges are prompting a much more granular temporal and spatial resolution to load forecasts that supports similar developments in models (Best Practice 31, Best Practice 32, and Best Practice 33). A best practice is to develop an hourly load forecast that reflects diurnal/nocturnal needs, as well as daily, weekly, and seasonal energy consumption to support a resource portfolio with energy-limited resources such as wind and solar. Several utilities such as PacifiCorp and Puget Sound Energy develop hourly load forecasts for use in production cost models (PSE 2021; PacifiCorp 2023). Similarly, load forecasts that match the model's geographic resolution will better recognize the spatial diversity of load growth and the spatial location of load with respect to transmission infrastructure. PacifiCorp, for example, historically has produced forecasts for the west and east sides of its service territory.

Increasing load from electrification is expected to continue in the coming decades, along with growth of large new loads such as data centers and manufacturing (see Best Practice 10). Forward-looking utilities are striving to properly model electrification and load growth in IRPs to ensure there are adequate resources to meet energy needs (ESIG 2024). Planners would separately forecast three key electrification variables: (1) adoption of end uses, (2) operation of these end uses, and (3) flexibility potential of such operation. Utilities have historically developed forecasts by customer segment, a practice that can be maintained as it creates a link to the ratemaking process. At the same time, electrification and load growth require an end-use approach. End-use forecasting methods have been used for decades, separately projecting saturation (i.e., customer adoption) and usage intensity for specific residential and commercial end uses (LBNL 2018). This approach is well suited for developing transparent base case and sensitivity load forecasts for emerging end uses such as EVs and heat pumps, and to track specific load growth for data centers, manufacturing, and other industries. Traditional time series-based approaches are insufficient to adequately represent emerging trends. Econometric approaches may be used as a method to predict adoption patterns, as part of an end-use model. An emerging method is propensity of adoption, which leverages machine-learning techniques to determine likelihood of customer adoption based on a wide range of characteristics and drivers (Ratchford and Barnhart 2012). In its 2023 IRP, PacifiCorp developed a propensity of adoption model to predict behind-the-meter PV adoption.

Adoption of new types of electrified end uses and decarbonization policies are tightly linked, although in many cases electrification is an economic decision for customers. The federal government has set several important decarbonization goals, including a 2030, all-sector greenhouse gas reduction target of 50 percent relative to 2005 levels (White House 2021) and securing a 100-percent clean electrical grid by 2035 (U.S. DOE 2023a). Numerous states have promulgated greenhouse gas reduction goals that include electrification, particularly for transportation (C2ES 2024; CESA n.d.). In addition, funding available through IRA supports electrification and decarbonization across the United States (RMI 2024b). A best practice for IRPs is to internalize any state-level electrification goals or electrification impacts of decarbonization policies. An extension of this practice entails running sensitivities that meet federal electrification and decarbonization goals to show the potential impacts of these policies. For example, Public Service Company of New Mexico modeled multiple "futures" in its IRP, including a National Climate Policy future that included high EV adoption and building electrification forecasts (PNM 2023).

Finally, past IRPs have used different statistical properties to reflect variability in their load forecasts. Typically, utilities use a median or 50/50 forecast for energy consumption forecasts and a 90/10 or higher peak demand forecast. The use of a higher percentile as a peak load forecast is not consistent with best practices that link capacity expansion decisions with resource adequacy assessments that ensure the system operates under a prescribed loss of load probability. A best practice is to use median forecasts for energy and peak demand and to let the resource adequacy assessment reflect capacity needs to address stress periods in the grid (see Best Practice 3, Best Practice 4, and Best Practice 5).

## Best Practice 9. Incorporate load flexibility into electrification forecasts

*Characterize load flexibility operational parameters consistent with electrification forecasts.*

Just as important as the magnitude of expected load growth is the shape of new power demand (NREL 2021d). This shape should reflect expected operational profiles for end uses and the flexibility potential of these operational profiles to meet one or more grid services. For example, EVs can achieve a desired state of charge using multiple charging profiles operating independently or in coordination with others. Assumptions about operational charging profiles will have differing impacts on peak load; similarly, assumptions about the willingness or ability of the EV owner to switch and adapt the EV's operational profile captures its flexibility.

Explicit modeling of EVs as a contribution to load is increasingly common, including in IRPs for Puget Sound Energy, DTE Energy, and Entergy Louisiana (PSE 2021; DTE 2022; Entergy Louisiana 2023). Notably, a large portion of this EV load is flexible especially when charging at lower voltage levels for extended periods of time. Different charging incentives can shift EV load to different times of day, and effective planners will model corresponding impacts in the IRP load forecast (Synapse 2020). NorthWestern Energy's 2023 IRP for Montana analyzes potential system and supply benefits of an EV charging management program, though the utility did not integrate the analysis directly into its planning models. Optimized EV charging can add flexibility that improves grid reliability by more effectively using renewable energy, shaving peak electricity demand, and helping maintain power quality (NREL 2021b). The same is true of distributed battery storage systems and demand response linked to newly electrified loads (NREL 2021c; NREL 2021b).

Modeling load flexibility requires using transparent assumptions from reputable studies or models that project time-based load-shifting potential.[16] Preferably, utilities perform or commission their own load flexibility studies and design programs to procure specific amounts of load flexibility identified in the studies. In its 2023 combined Clean Energy Plan and IRP (PGE 2023), for example, Portland General Electric discusses the growing role of flexible loads and describes plans to use findings from

[16] Examples include NREL's EVI-PRO EV infrastructure projection tool, which allows users to develop different load shapes for EVs (NREL EV-Pro n.d.-b) Additional resources to support load forecasting include (NREL and LBNL 2023) and (LBNL 2023b).

implementation of its virtual power plant to inform future modeling of flexible load.[17] Comprehensive IRPs specify plans to achieve the level of load flexibility included in the modeling, including near-term activities in the action plan.

Demand response has been part of IRP for decades. Load flexibility modeling described in this section, however, is an emerging practice with open questions about certain best practice elements. For example, most IRPs that examine load flexibility potential for EVs do so as part of their load forecast and internalize this potential as a load modifier, or as load forecast scenarios. An alternative approach would treat load flexibility as a resource and study it as part of market potential studies traditionally used for demand-side management (DSM) through energy efficiency and demand response programs funded by utility customers (see Best Practice 19 through Best Practice 22). How to incorporate load flexibility in resource adequacy assessments, stochastically characterize flexible end uses, and assess their effective load-carrying capability are emerging issues.

## Best Practice 10. Plan ahead for large load growth

*Thoughtfully model and plan for the rapid rise of data center, industrial, and manufacturing loads.*

Over the past several years, data center load driven by the rise of AI, coupled with increasing manufacturing and industrial load, have become significant drivers of projected future resource needs in jurisdictions across the country, most notably in Arizona, Virginia, Georgia, and Texas (Martine Jenkins and Skok 2024). This new challenge comes as utilities are wrestling with increased load from transportation and building electrification and a changing resource mix as baseload fossil fuel units retire and carbon-free energy resources come online.

The uptick in demand represents a turning point over the previous decade when the United States experienced relatively flat to declining demand growth due in large part to increased DSM and distributed generation deployment (Grid Strategies 2023). Best practices in resource planning will be different for this new era of growth than they were during the past decade. Before utilities build or acquire new resources to meet this new load, there are actions they can take to understand the level of certainty about potential new loads, manage the impact of new loads on system peak, determine the lowest-cost way to meet new loads while maintaining system reliability, and understand the impact of new loads on utility customers and the electricity system broadly. Critically, in this new era of load, customers will be best served if utilities shift from viewing load as a static input to be served in a given year, to viewing the timing of serving load as another decision the resource plan can consider and optimize.

[17] Oregon-regulated utilities also file multi-year flexible load plans with the PUC every 2 years (OR PUC 2020).

The first step for utilities is to determine what level of data center and industrial load is likely to materialize within their service territory. There are varying views on whether future load growth projections for these sectors at large are accurate or overstated. But at the individual utility level, utilities and regulators can take specific measures to avoid building for speculative load and incurring associated costs for all customers:

- Utilities can develop rigorous methodologies for evaluating the likelihood that each potential data center and industrial customer will come online and materialize as actual load. Methods include weighing potential new customers individually based on development milestones, or requiring customers to meet construction and service commitment levels (at which there is a reasonably high level of conversion to actual load) in order to be included in load forecasts. This is especially important given that many companies are looking for the best deal for power and are shopping around their load to multiple utilities. Early-stage negotiations of basic contract terms are insufficient to assume load will materialize. This type of customer-specific load forecasting is not new; utilities have used it to account for large industrial customers in the past. And it can be refined and applied moving forward.
- Utilities can model multiple load scenarios to understand what level of new resources are needed, and which resources are most cost-effective, based on different levels of load achieving commercial operation.
- Regulatory commissions can require utilities to demonstrate that new, large-load customers have reached specific construction milestones before they permit cost recovery of new generation resources built to serve them. In states where Certificates of Public Convenience and Necessity (CPCN) or other forms of pre-approval are required for cost recovery of new assets, commissions can decline to provide pre-approval before new load customers reach certain milestones. In states where pre-approval is not required, in general rate cases the commission can deny cost recovery for assets built to serve new load prior to the load reaching specific milestones. Commissions can also take other measures such as requesting that utilities perform modeling runs with load forecasts that remove speculative load.

The second step is for a utility to determine the timeframe over which it can reasonably meet new load and how it will serve and manage that load. While utilities have an obligation to serve customers within their service territory, they do not have an obligation to do so on a specific timeframe or with a given set of resources. A utility's obligation is to serve load in a way that manages system costs and maintains system reliability. Utilities can use multiple tools to:

- *Manage load temporally through demand flexibility.* While some data center load is relatively flat and has a high load factor (and therefore has minimal potential for temporal management), other new load offers opportunities for energy efficiency and demand flexibility. For customers with temporal flexibility, utilities can offer tariffs and DSM programs that incentivize customers to reduce usage when demand and prices are highest (RMI 2024a).
- *Manage load geographically by incenting utilities to site in certain locations.* Utilities with access to surplus generation or high penetrations of low marginal cost resources (such as wind) can offer tariffs that incentivize companies to locate in their geographic region. Utilities with more

limited access to low marginal cost resources can set tariffs that disincentivize location in their region.

- *Set a timeline for serving new load that minimizes total system costs.* Utilities can assess the timeline for new projected load connection in conjunction with the changing cost of adding new generation resources and grid-enhancing technologies over time. Rather than viewing load as a given in a specific year, utilities can view the timing of load connection as another factor to consider in minimizing system costs. If a new customer wants grid service within 3 years, but a 5-year timeframe may allow the utility to build new generation at a substantially lower cost to the system, that can be factored into planning for the new load.
- *Ensure that resources used to serve new load are part of a least-cost plan.* When utilities are considering whether to retain existing fossil-fuel resources beyond previously planned retirement dates to serve load and maintain reliability, best practice is to include the full forward-going costs of maintaining the fossil fuel plants, as well as the cost to build and maintain new resources. An existing asset that requires substantial investment to sustain it is less likely to be economic than one that requires minimal near-term operations and maintenance (O&M). Analysis of the cost of reliance on existing fossil fuel resources is especially relevant given that many new data center customers have explicit 24 x 7 carbon-free energy goals (WRI 2023).
- *Incentivize customers or third parties* to (1) build dedicated resources owned by or contracted by the customer to manage load and mitigate system impacts and (2) deploy state-of-the-art measures to ensure operations are as efficient as possible. If customers can manage some of their own peak load through efficiency and on-site generation, provide their own backup power, or provide other grid services, utilities may be able to build or acquire fewer generation units and make fewer grid investments and, in return, offer lower tariffs to the new load customers.[18]

The third step, to be conducted in tandem with the second step, is for utilities and new large-load customers to understand how new load impacts total system cost and cost allocation. While these issues have traditionally been addressed in rate cases outside of the IRP process, information about how new load will impact total system costs and cost allocation can be important in helping new customers decide where to locate, when to begin construction, and whether they should self-supply to manage their load. Analysis of how new load impacts system costs overall and individual customer classes specifically will help utilities manage cost increases and cost-shifting resulting from new load.

Finally, states can consider measures to address the pace and type of new loads that locate in their jurisdiction. While some new loads may bring economic benefits such as jobs and tax revenue, others—such as bit-coin mining—are more likely to increase electricity system costs while bringing few jobs.

[18] While these recommendations focus on actions that utilities and commissions can take to manage new load, measures and mandates can also come from the state legislature. These fall outside the scope of this guide.

## Best Practice 11. Transparently represent distributed generation and storage

*Develop forecasts of distributed generation and storage adoption and incorporate them into the modeling process.*

Historically, IRPs have focused demand-side resource analysis on energy efficiency and demand response. Many states set up utility customer programs to encourage adoption of these demand-side measures across market segments and income groups. Even with higher levels of distributed PV and storage adoption that may prompt revisiting the scope of demand-side resources in IRP, the relative lack of focus on PV and storage remains true. For example, Arizona Public Service has one of the highest levels of distributed PV penetration in the country and its demand-side resource analysis remains focused on energy efficiency and demand response (see more on Best Practice 19 through Best Practice 22). However, planners still need to forecast adoption of distributed resources that help meet load needs and potentially defer T&D investments. In general, this analysis appears as part of the load forecast section in IRPs and is treated as a load modifier, so it is netted out of the load forecast. Duke Energy Indiana's 2021 IRP is an example of this approach (DEI 2021).

Customer-sited distributed generation and storage, community solar, and utility-owned distributed resources require different approaches. This stems largely from (1) with how much notice the utility has about deployment and operation of these resources and (2) the compensation mechanisms for these resources that inform adoption and operation. As with end uses, best practice is to forecast or simulate adoption and operation of distributed resources separately.

Planners typically forecast adoption of customer-sited resources through a linear regression that relies on current adoption trends and expected payback. Best practice is to use a propensity of adoption method that captures expected changes in customer preference, regulations, and policies. Portland General Electric and Puget Sound Energy leveraged the National Renewable Energy Laboratory's (NREL) dGen tool (NREL dGen n.d.-a) in their latest IRPs to forecast customer adoption using a propensity of adoption approach (PGE 2023; PSE 2021). In contrast, Duke Energy Indiana implements a linear regression method based on the Itron MetrixND platform (Itron, n.d.; DEI 2021). For community solar adoption forecasts, planners can look to existing support programs, which typically have adoption caps. Utility-sited resources can be retrieved from the utility's distribution system plans (see Best Practice 47).

Operation of resources depends in part on whether they are dispatchable. Operation of customer-owned distributed resources are best modeled at an hourly basis and compared against hourly load profiles for each customer segment in order to estimate net metering or net billing credits when relevant. For example, Duke Energy Indiana uses 20-year irradiance data to simulate rooftop solar production for selected locations within its service territory and produces a typical day hourly generation profile for each month of the year. Customer-owned distributed storage requires elaborate methods to forecast dispatch and determine contributions to the grid. Given its relatively low adoption, no clear best practice exists to model customer-owned distributed storage.

Deployment and operation of customer-owned distributed resources is heavily contingent on its economics, which in turn is influenced by rate structures, compensation schemes, and supporting policies. A current best practice is to make clear assumptions about the regulatory and policy environment, and to develop a sensitivity analysis if a key regulatory or policy condition may change during the planning horizon (see Best Practice 30). An emerging best practice is to consider how distributed resource operation could be influenced if these resources are aggregated under virtual power plants, as Portland General Electric did in its 2023 IRP. Substantial growth of behind-the-meter storage will likely enhance rooftop solar economics amidst changes in net metering regulations, as well as provide resilience and reliability benefits (LBNL 2023d).

The consideration of avoided costs for customer- or utility-owned distributed resources is generally a matter of statute, even though it is technically adequate to recognize the upstream benefits from these resources where the models do not.[19] The analysis can consider avoided costs of transmission, distribution, and environmental and internalize them in the overall system costs. For example, Arizona Public Service's 2023 IRP included a market potential study that produced and internalized avoided costs of energy efficiency measures, which can be extended to other types of distributed resources (APS 2023).

The current practice of treating distributed generation and storage as load modifiers suffers some of the same issues as the traditional treatment of energy efficiency, demand response, and other distributed energy resources (see Best Practice 19 through Best Practice 22). In particular, conflating load and distributed resources for resource adequacy assessments introduces distortions due to the inherent differences in risk and uncertainty profiles. While using net load may be fine for lower penetrations of distributed energy resources, emerging best practice would require separately modeling distributed generation and storage from load in resource adequacy assessments.

[19] Capacity expansion models would typically internalize capacity and energy benefits of distributed energy resources when considered both as a load modifier or competitive resource, since they displace capacity and energy needs from supply-side resources.

## Supply-side resource inputs

## Best Practice 12. Use accurate assumptions for the costs of new resources

*Use accurate cost assumptions for new resources that reflect current market data and include all relevant programs and incentives.*

The cost to procure new resources changes constantly. The most accurate way to develop present-day cost expectations for most resources is through real market data obtained directly from project developers or through competitive, all-source requests for proposals (RFP). This data reveals actual procurement costs at a specific place and time. These costs can be sense-checked against cost estimates in the best-available public resources, such as the NREL's Annual Technology Baseline, U.S. Energy Information Administration's (EIA) Annual Energy Outlook, and EPRI's Generation Technology Options Report, or proprietary data from industry sources such as Black and Veatch, Wood Mackenzie, and others (NREL ATB 2024; U.S. EIA AEO 2023a; EPRI 2024). In Colorado, utilities such as Public Service of Colorado use both generic cost assumptions and market data. First, they develop their IRP models using generic cost assumptions. Once the model is approved by the commission, they use the model to evaluate bids from a competitive RFP (PSCo 2021). This allows the utility to see what resources the IRP model selects directionally using public industry sources, and then to use actual cost data to select specific projects.

If RFP results are out of line with expectations based on public and industry sources, utilities can conduct supplemental analysis to better understand and explain the source of the deviation. This can be particularly important during times when market disruptions occur, such as the supply chain challenges and inflation resulting from the COVID-19 pandemic. For its current 2025 IRP cycle, Puget Sound Energy hired Black and Veatch to develop cost assumptions for its IRP based on the consultant's experience as a project developer. The utility shared the study through its Resource Planning Advisory Group. As part of the study Black and Veatch will compare the cost assumptions it developed for Puget Sound Energy to those published by NREL in its Annual Technology Baseline and account for any major deviations (PSE n.d.).

Future cost trajectories are best developed based on technology maturity curves, such as those used by NREL and EIA, rather than adopting existing simplifying assumptions. Such assumptions may seem impartial, but they can skew results for or against specific resource types. Best practice is to avoid using simplifying assumptions when not supported or justified by research or analysis. For example, reliance on flat cost trajectories for all resource types when there is uncertainty about how resource costs will change in the future is not a neutral assumption. It results in bias in favor of mature generation resources with minimal additional cost declines expected, such as gas plants, and against newer

> ***The most accurate way to develop present-day cost expectations for most resources is through real market data obtained directly from project developers or through competitive, all-source requests for proposals.***

resources with larger technological advancement and cost declines expected in the future, such as solar PV, wind, and BESS.

Additionally, new resource cost assumptions will be most accurate and useful if they are developed to incorporate all relevant and up-to-date tax and program incentives as well as any other relevant funding that are likely to affect a resource's cost. Beyond correctly modeling all credits and incentives that are available for new generic and specifically planned resources, utilities can use the availability of credits and incentives to drive project selection and placement. It may be appropriate to model location-specific new resources rather than view all new resources as generic.

The IRA, in particular, changed the cost landscape for wind, solar, biomass, geothermal, battery energy storge, CCS, and hydrogen. Under the IRA, facilities generating energy from these resources are eligible for either a production tax credit based on their generation or an investment tax credit based on their size. Added bonus tax credits are available for solar and wind facilities located in energy communities and that use domestically manufactured materials. Nuclear plants and advanced energy projects can also receive tax credits through the IRA (White House, n.d.). The cost implications of these and other features of the IRA merit consideration when developing IRP inputs, including all potential bonus adders (RMI 2024b) and bonus tax credits available from siting new resources at the site of a retired or retiring fossil plant.

## Best Practice 13. Represent the full cost and risk of advanced technologies

*Ensure the model reflects and captures the full range of costs and risks associated with advanced technologies.*

In the case of new or particularly complex technologies that are not commercially available, there may be no market data on which to rely, and annual studies from NREL or the EIA may have limited cost data. This is especially important as utilities consider advanced decarbonization solutions such as CCS, carbon capture utilization and sequestration (CCUS), advanced and small nuclear reactors, long-duration battery storage, and conversion of natural gas plants to fire or co-fire with hydrogen. While pilot projects may provide useful data points, such projects are by their nature not in the commercial stage. Therefore, planners will want to use cost and performance data cautiously and account for differences between the pilot and the planned or modeled project.

Megaprojects, especially those that rely on new technology, require special attention for cost estimation and sensitivities. History has shown that such projects are prone to dramatic cost overruns and rate impacts for utility customers (Rand 1988). The larger and more complex a project, the greater the likelihood that it will experience extreme cost growth (Rand 2017). Care must be taken to model the potential for greater risk with large projects and uncertainty with new and untested technology. The examples below from Mississippi (Schlissel 2009; Amy 2018) and Georgia (U.S. DOE 2023b) illustrate some potential issues.

### Advanced Technology Example: Kemper County Coal Internal Gasification Combined Cycle (IGCC) Megaproject

The Kemper County IGCC project was intended to combine a new coal gasification plant with carbon capture and storage. When Mississippi Power Company sought a Certificate of Public Convenience and Necessity for the project in 2009, it estimated that the first-of-its-kind plant would cost $2.1 billion. There were warning signs at the time that costs were likely to increase. None of the estimates in the company's filing were subject to cost caps, few of the vendors for parts had been selected, and detailed design for the project had not yet begun. The cost to build traditional coal units at the time had already been trending upward for years. One intervenor in the 2009 regulatory docket recommended modeling sensitivities that increased costs 20 to 40 percent. Even these recommendations underestimated how much costs would rise. By 2018, the carbon capture portion of the project had been canceled, and the capital cost of the project had reached $7.5 billion. Customer rates had been 15 percent higher for 2 years, and after years of debate and testimony, utility regulators approved a settlement that required utility investors to absorb about $6.4 billion of the cost. "The economics really didn't work out and the technology was hard to perfect," the Mississippi Power CEO stated after the settlement.

In general, larger expected capital expenses warrant more careful review. Including a worst-case cost scenario informed by data and outcomes from other recent and relevant projects as an IRP sensitivity is good practice. This might take the form of a cost sensitivity that is plus or minus 20 or 50 percent, or even 100 percent, depending on the order of magnitude of cost ranges available from pilot projects, studies, or other uses of the technology. Such a scenario allows utilities and commissions to weigh and understand the costs and risks of the new technology against the likely much narrower bands of uncertainty and risk associated with commercially available alternatives to determine what cost range would make a technology cost-effective and worth the risk.

### Advanced Technology Example: Georgia's Vogtle Nuclear Plant Megaproject

In 2009, at the start of site construction, Vogtle nuclear plant's Unit 3 and Unit 4 project in Georgia was expected to cost $13 billion. By June 2022, the project cost had increased to over $32 billion. According to the DOE, almost all of the overrun was attributable to four factors in the cost of construction: the need to redo improperly executed work along the way, supply chain delays, low labor productivity, and worker attrition. These issues are not necessarily unique to building nuclear power plants. Although they may be difficult to predict, greater contingency planning is needed to properly parameterize the cost of a project this size. Regarding nuclear projects specifically, the DOE's "Pathways to Commercial Liftoff" report on nuclear sets a plus-or-minus 20 percent threshold in estimating project costs as an aspirational goal for coming in on budget for future nuclear, indicating high cost uncertainty (U.S. DOE 2023b).

## Best Practice 14. Include realistic assumptions about resource availability timing, without unnecessary constraints

*Understand limits and constraints on timing and schedule for new resource construction without unnecessarily constraining resource builds.*

In addition to developing accurate capital cost assumptions for new generation resources (discussed in Best Practice 12), robust IRP capacity expansion modeling includes factors related to timing of construction. These include the risk of construction delays due to siting and permitting, local opposition, the interconnection queue, and supply chain constraints. Utilities must carefully balance between letting optimization models optimize and imposing constraints to reflect real-world construction and interconnection bottlenecks. The best way to address this tension is to model scenarios with and without supply constraints and vary constraints over time to reflect realistic expectations about factors that will impact future resource availability.

Scenarios without constraints provide valuable information on the economically optimal solution and provide directions to the market on what the utility may be looking to procure. A more constrained scenario informs the utility about alternative options if it cannot overcome near-term supply constraints. Scenarios with static and unchanging constraints (for example, an annual build limit of 300 MW for a specific resource type for the entire study period) may be less useful than scenarios that vary constraints over time to reflect potential changing market conditions.

Supply chain issues following the COVID-19 pandemic, as well as constraints in labor availability (especially for specialized labor), demonstrate the importance of planning for risks and uncertainties related to labor and materials availability and delays. Public Service Company of New Mexico and El Paso Electric, for example, renegotiated multiple supply agreements for solar resources due to COVID-19-related supply chain challenges (PNM 2023). Although issues stemming from the pandemic have gradually improved, they have affected planning across consecutive IRPs. To incorporate delays such as these, planners either run sensitivities that deterministically alter new resource builds to reflect expected conditions or, in the case of supply chain constraints, treat them as annual, maximum build limits. DTE Energy's 2022 IRP implemented annual build limits for all resources, including renewable energy resources, citing challenges with the items mentioned above as well as recent RFP experience (DTE 2022). While the utility included these constraints throughout the study period, the IRP states that "The Company is expecting to build on these advancements and efficiencies learned through the execution of the first several years of projects, thus, the annual MW limit increased over time" (DTE 2022, 102).

While ongoing interconnection reform efforts aim to address delays in resources coming online, current and potential future interconnection-related delays are still factors to address in IRPs. Utilities can demonstrate to regulators and stakeholders that an adequate amount of new generation planned in the near term will be able to interconnect in time and provide a contingency plan. One approach to interconnection-related uncertainty is to be more proactive with resource procurement (PA Consulting 2023). For example, if IRP modeling shows it is economically optimal to add 500 MW of new solar by 2028, the utility can issue an RFP ahead of need for that amount and timing, as well as additional levels and potentially earlier timelines. Evaluation of bids at levels in excess of the targeted amount is useful for addressing longer-term needs.

At the same time, processes and policies designed to hasten interconnection, such as surplus interconnection and generator replacement,[20] are worth exploring to understand cost and time implications of using existing interconnection rights to bring additional resources online. Using existing interconnections can help achieve economies of scale and accelerate deployment timelines. Utilities are increasingly seeing the benefits of considering existing interconnection rights in resource planning. Xcel Energy, Otter Tail Power Company, and Great River Energy in Minnesota, for example, have all planned or executed projects using existing interconnection rights in their jurisdictions (Xcel Energy 2023; Otter Tail 2021; Great River Energy 2021). All three utilities are transparent about the cost and timing benefits of such projects. Otter Tail sees “the transmission queue for new interconnection of wind as a significant hurdle to introducing new wind resources outside of utilizing surplus interconnection at existing plants (Otter Tail 2021, 65)". Xcel Energy states, “By using existing grid connections, we’re able to provide customers with carbon-free energy in the most efficient and cost-effective way” (Xcel Energy 2023). Great River Energy likewise states, “Use of the existing [generator interconnection agreements] is beneficial for our membership as we receive more advantageously priced wind in our portfolio as a valuable hedge while avoiding significant costs, resulting in a net benefit to our members” (Great River Energy 2021, 1).

## Best Practice 15. Limit renewable integration cost adders

*Study and fully justify all integration cost adders applied to new renewable energy resources.*

As the penetration of renewable energy resources on the grid increases, utilities need a way to quantify and represent the grid services needed for balancing, such as transmission upgrades, regulation and reserves, voltage support, and real-time variability. Planners can capture some of these costs in capacity expansion and production cost models. Alternatively, utilities can develop renewable energy integration costs based on external studies and evaluate the impact of increased renewable energy deployment on the need for system-level upgrades and grid services.

Caution is needed when conducting and evaluating these studies. First, the results are highly dependent on the resource plan modeled and are often more reflective of the existing resource mix than the level of new renewable resources added. Santee Cooper’s solar integration study modeled as part of its most 2023 IRP illustrates this challenge. The utility assumed that Winyah, a 1,260 MW coal-fired power plant, would not retire until 2031. Since many coal plants cannot ramp up and down quickly, modeling results indicated challenges (cycling, re-dispatch) with integrating a high penetration of solar resources until after 2030. After the plant retirement date and replacement with faster-ramping peaking resources, the cost of renewable energy integration dropped significantly. The utility used these findings to support its decision to delay the retirement of Winyah from 2028 to 2031. However, the study results did not

[20] Surplus interconnection refers to an unused part of an interconnection service. When a generator retires, if the holder of the interconnection service seeks to keep the service and install replacement resources, they can often do so without having to conduct a full interconnection study and wait in the interconnection queue.

support this finding—instead they showed that delaying Winyah's retirement was what was driving high solar integration costs. Santee Cooper did not evaluate integration costs under any earlier retirement scenarios, where Winyah would be replaced by more nimble resources such as gas combustion turbines or BESS.

Another area for caution is that the results are also often portfolio-specific; they are not wholly transferable across portfolios and scenarios that rely on different resource mixes. A utility would need to model integration costs across multiple resource portfolios to more accurately capture the grid impact of new resource additions. Modeling might double-count costs across the integration cost study and the capacity expansion modeling if the utility is not careful, especially where the study is conducted in isolation from the rest of the resource planning process. This can be avoided by syncing up the integration studies with the resource planning modeling and carefully tracking the services and costs that are quantified already in the production cost and capacity expansion modeling. Finally, system costs that would be incurred regardless may be attributed to renewables only. This can be avoided with robust modeling and transparent analysis.

## Best Practice 16. Model all avoidable forward-going resource costs

*Model all avoidable, forward-going costs for all existing resources, including coal and gas plants.*

Appropriately modeling retirement of existing fossil fuel units requires accounting for all costs that are avoidable. That includes avoidable capital costs that would be included in the rate base, fixed O&M costs included in retail rates, and variable operating costs (including fuel and variable O&M expenses). While it is common for utilities to model fuel and other variable costs, utilities sometimes omit certain capital expenditures and fixed O&M from the model and instead address these costs in a post-processing step (or not at all).[21] If the model does not evaluate all avoidable costs, it does not factor them into retirement decisions. Modeling of avoidable costs can be coupled with modeling of unit retirements to fully evaluate the economics of continued reliance on existing resources, as discussed in Best Practice 37.

Generally, utilities develop capital expenditure schedules based on specific projects planned in the near term. Often these schedules only cover the next 3 to 5 years, with projected spending substantially dropping off beyond this period.[22] This approach regularly underestimates likely capital expenditures by ignoring spending more than a few years out, as well as spending associated with unplanned outages, non-routine expenditures, and uncertain future environmental regulations. The lumpiness and unit-specific nature of ongoing capital additions to power plants can be a challenge to represent in IRP modeling, but these costs can be substantial.

Modeling capital expenditures properly, including annual variations and unit-specific detail, is important to resource planning decisions such as whether and when to retire a power plant from service.

[21] For example, Santee Cooper did not enter projections of capital expenses for its coal plants in the EnCompass capacity expansion model. Instead, the utility included capital expenditure differences by portfolio in the final net present value power costs for portfolios that varied from others in terms of coal plant retirement dates (Public Service Commission of South Carolina Docket No. 2023-154-E, Santee Cooper Response to Sierra Club Data Request 1-8).
[22] This is based on some of the authors' experience reviewing projected unit cost data in numerous rate cases.

Additionally, environmental compliance costs are often large enough (in the tens to hundreds of millions of dollars range) to drive a power plant retirement decision. Even though there is uncertainty regarding which aging facility parts may break down, when, or the likelihood of environmental regulations to increase costs, unexpected costs are all but certain. Ignoring costs because of uncertainty in the exact amount or timing results in underestimates of future system costs. For example, in Tri-State's 2023 Electric Resource Plan (ERP) in Colorado, the company's original modeling did not account for future environmental compliance costs, particularly those related to the recent U.S. Environmental Protection Agency (EPA) greenhouse gas rule under Section 111. The settlement agreement in that case, which is currently before the state regulatory commission, would secure improved modeling that accounts for these costs (CO PUC 2023).

It is best practice for a utility to benchmark capital cost projections for a unit against its spending at the plant in recent years to evaluate whether future projections may deviate substantially from recent experience. Another option is to review and incorporate into the utility's analysis current or forward-looking industry average estimates, such as average annual values based on unit type, size, and age developed by engineering firm Sargent and Lundy. The EPA developed a unit-specific "life extension cost" for use in its own capacity expansion modeling that simulates a large, one-time sustaining capital cost investment incurred when units reach a certain age (U.S. EIA 2019; U.S. EPA 2023). If the utility's projections deviate substantially from both its own historical data and industry averages, best practice is to evaluate why and adjust forecasts for modeling—or justify the deviation in the IRP.

Another best practice is to develop a schedule of planned maintenance and capital expenditures based on a unit's retirement date that factors in a typical ramp-down in spending in the years just prior to retirement. Scenario modeling is the best approach, because programming a capacity expansion model to vary capital expenditures schedules based on a unit's retirement date can be tricky.

## Best Practice 17. Model battery energy storage options

*Model a variety of short- and long-duration battery storage options to capture the differential value each option can provide to the system.*

Energy storage is a highly flexible resource with the potential to become ubiquitous in modern power systems as both a capacity resource and a grid resource. Storage is already playing an outsized role in near-term resource deployment (U.S. EIA 2024b). Typical current IRP modeling approaches may oversimplify aspects of the design, operation, and value of storage resources, missing their full value stack (RMI 2015). Some utilities are demonstrating improved practices. AES Indiana, for example, evaluated the value of BESS as a capacity resource and for providing grid services. As a result, the utility deployed a 20 MW battery to provide primary frequency response, an important ancillary service (AES Indiana 2024). Robust IRPs will evolve to capture the reliability and resilience benefits of BESS, including for resource adequacy and ancillary services.

The value of storage as a flexibility resource is a function of the particular portfolio. The value changes as the portfolio and system needs change. For example, when a utility is short on flexible resources, lithium-ion batteries provide significant value to the system. But once the utility has sufficient sub-hourly reserves, the value drops to the market value—that is, until the utility's system or demand changes again, and its demand for flexible reserves increases.

Overstating the value of various value streams risks adding the wrong kind of storage. While short-duration lithium-ion batteries may be well suited to provide an initial quantity of reserves, long-duration storage such as an iron-air battery may be a more cost-effective and efficient solution for longer-term back-up and reserves. Most utilities model at least one type of short-duration storage[23] in IRPs, most commonly 4-hour BESS. Other short-duration options, such as 2-hour and 8-hour BESS, offer different services and economics that may fit better with specific grid needs. A 2-hour BESS offers narrow peak services but is lower cost than a 4-hour BESS and may be a more economic option for meeting limited periods of need. An 8-hour BESS can provide power for longer periods of time but is more expensive than a 4-hour BESS. It is important to accurately model the costs and capabilities of multiple storage options to determine the duration(s) that are the best fit for the utility's system (EPRI 2023a).

Another value of storage is its ability to enhance power system resilience. Storage can be part of microgrid and fully islanded systems, and it can make the system less dependent on fuel delivery or weather-based performance in times of stress. The IRP framework rarely captures these unique aspects of storage value. At the very least, these benefits can be qualitatively considered in portfolio screening processes.

### Looking Ahead: Internalize storage resilience benefits in modeling

An aspirational practice entails internalizing the resilience benefits of storage within IRP capacity expansion models. This would entail enabling capacity expansion models to represent the stochastic elements that underpin resilience valuation, as well as modeling microgrid formation and operation as a resilience strategy.

For long-duration storage, several technologies are in the early stages of development or commercialization. Technologies include mechanical, thermal, electrochemical, and chemical systems that discharge stored energy for at least 8 hours and up to 1,000 hours, depending on the technology. Even though these technologies are in a nascent stage of development, utilities can model them as part of a resource plan and rely on them as replacement resource options further out in the study period (beyond the next 5 years).

Long-duration storage can provide firm, dispatchable, zero-carbon capacity, which is a need many utilities have identified. Our review of 20 IRPs from 2023 and 2024 found that 12 included at least a discussion of long-duration storage technologies, and 8 included them as a resource option.[24] For example, Southwestern Public Service Company in New Mexico modeled several scenarios that relied on long-duration energy storage for its 2023 IRP (Xcel Energy New Mexico 2023).

To consider long-duration storage in IRP, utilities need data on various technologies and need to know how to model them. While long-duration storage is not yet represented in commonly used sources of

[23] Definitions for short- and long-duration storage vary. Some parties also use the term medium-duration storage. In this guide, we refer to short-duration as less than 8 hours and long-duration as 8 hours or longer.
[24] IRPs vary considerably in defining "long-duration," so interpreting this finding requires a fair degree of caution.

information on capital and operating costs of generation and storage resources, such as NREL's Annual Technology Baseline, utilities can use other publicly available data sources. One such source is McKinsey & Company's report, *Net-zero power: Long duration energy storage for a renewable grid* (McKinsey 2021). Utilities can also refer to other industry projections of capital and operating costs and parameters for long-duration storage technologies, issue a Request for Information from technology developers prior to IRP development, or use data from recent RFPs. As with solar, wind, and lithium-ion battery technologies, it is reasonable to assume a downward cost trajectory for BESS technologies associated with technological advancement and learnings, as well as resolution of supply chain challenges in future years.

## Best Practice 18. Be consistent in treatment of emerging technologies

*Model the costs, availability, and risks of emerging technologies in a consistent and unbiased manner.*

Planners can model emerging supply-side technologies in IRPs despite uncertainty related to costs, procurement, and performance. As deployment of BESS, solar, and wind over the past decade has demonstrated, the cost to deploy emerging technologies can change quickly. Emerging technologies are likely to be part of a least-cost portfolio, especially in a decarbonized future. The challenge for planners is to ensure they evaluate emerging technologies consistently and to make informed, transparent decisions about which emerging technologies to include in capacity expansion modeling. Consistent, unbiased evaluation allows utilities to understand the cost and system impacts of particular technologies and clearly communicate to regulators and stakeholders the reasoning for technologies utilities included and omitted from resource plans for a given timeframe.

Examples of emerging supply-side technologies include small modular nuclear reactors, long-duration energy storage, hydrogen, and CCS, to name a few. A best practice is to evaluate emerging technologies for cost, availability, potential, deployment timing, and associated performance risks to both shareholders and utility customers. Portland General Electric's 2023 Clean Energy Plan/IRP (PGE 2023) includes a discussion of all of these technologies, among others, though not all were included in portfolio modeling. Other IRPs, such as the 2024 Xcel Upper Midwest IRP (Xcel Energy 2024), include emerging technologies in the capacity expansion model, though typically for limited sensitivity runs after the date by which they are expected to be commercially available. Evaluation of emerging technologies also may occur outside of IRP, in supplementary studies.

While available information varies by emerging technology, it is important that the IRP clearly discuss how the utility considered each technology and evaluated them fairly. It would be inappropriate for planners to include one resource type while omitting another without clear support, including the timing of its expected availability. For example, modeling for Santee Cooper's and Dominion Energy South Carolina's 2023 IRPs includes small modular reactors as supply-side resources as emerging resource options, but no others (Santee Cooper 2023; Dominion SC 2023). This choice effectively gives small modular reactors a privileged status among technologies that have yet to reach commercial viability and could bias results in favor of the reactors.

As a general rule, utility plans that rely on emerging technologies in the near term (e.g., 5–10 years in the future) draw substantial scrutiny and skepticism. Cleco Louisiana, for example, modeled the Madison coal plant installing CCS technology in 2028 in all scenarios for its 2021 IRP (Cleco 2023). CCS is not currently deployed by any electric utility in the United States.[25] While CCS is likely to be commercially available at some point in the future, it is not realistic to assume that any utility can economically deploy the technology within the next 5 years. Likewise, good planners make it clear what assumptions are required for an emerging technology to be feasible and reasonable. For instance, characterizing how much of a capital cost overrun would eliminate cost-effectiveness of the technology can help illuminate risk and contextualize portfolio results.

In some instances, cost parameters for emerging technologies are too uncertain to estimate. In the context of deep decarbonization scenarios, Duke and other utilities have modeled an emerging resource with all of the performance characteristics and costs of a combustion turbine, but without greenhouse gas emissions or fossil fuel costs. This so-called "clean capacity resource" typically first appears approximately 20 years in the future, in the 2040s, and represents a proxy resource that is expected to be developed by that timeframe. The advantage of this method is that it allows utilities to run scenarios that examine what type of new resource may be needed in a deep decarbonization future and what a least-cost portfolio may look like should such a resource materialize. However, there is inherent risk in modeling scenarios that feature unknown and unproven technologies. The greater the importance of such technologies in the company's preferred portfolio, and the further they are from common commercial practice, the more information stakeholders and regulators will need from the utility to understand the risks.

## DEMAND-SIDE RESOURCE INPUTS

The IRP process began with least-cost planning in the 1980s, developed in part to explicitly account for demand-side resources to meet load (LBNL and ORNL 1989; Hirst and Goldman 1990). Traditionally, utilities have developed a companion study—the market potential study—that quantifies the technical and achievable/economic potential of demand-side resources as a part of the utility's preferred portfolio. The market potential study has historically focused only on demand response and energy efficiency. This section of the report focuses on practices for these resources. (For treatment of other distributed energy resources, see Best Practice 11.)

Using market potential study results, an IRP internalizes the effects of energy efficiency, demand response, and other demand-side resources in one of two ways:

1. *Load modifier approach*. This is the most common method and relies on demand-side resource potential studies performed outside of the IRP process. Using this approach, planners incorporate cost-effective demand-side resources into the IRP as a load reduction. Examples of utilities that used the load modifier approach in recent IRPs include Jacksonville Electric

[25] See the Advanced Technology Example on page 33. Southern Company attempted to construct an IGCC unit with a CCS plant at Kemper. This resulted in costs that were three times the initial project estimate (from $2.5 billion to $7.5 billion) before the Mississippi Public Service Commission ultimately pulled the plug on the project and ordered Mississippi Power Company to continue to operate the plant on natural gas.

Authority, Avista, and Dominion Energy South Carolina (Black and Veatch 2023; Avista 2023; Dominion SC 2023).

2. *Competitive resource approach*. This approach incorporates demand-side resources in the capacity expansion model as priced, competitive resources that can be selected endogenously as part of the capacity expansion optimal decisions. The Northwest Power and Conservation Council (Northwest Council) uses this approach for its regional power plans under the federal *Northwest Power Act,* as do utilities such as PacifiCorp, Portland General Electric, and Xcel Energy (Northwest Council 2022; PacifiCorp 2023; PGE 2023; Xcel Energy 2024).

Rather than prescribe one approach, the following sections provide best practices for implementing each of the methods, depending on the approach regulators or utilities select.

## Best Practice 19. Ensure thoughtful and consistent assumptions for demand-side resources

*Ensure assumptions driving demand-side resource characterization potential are thoughtful and consistent with other assumptions in the IRP.*

Both the load modifier approach and competitive resource approach need to reflect actual program implementation and evaluation practices closely, including: (1) realistic program design and implementation practices, (2) appropriate levels of measure adoption rates (reflecting various non-economic factors), (3) measure and program costs, and (4) policy and regulatory requirements.

While market potential studies themselves are outside the scope of this guide, best practices entail including in these studies emerging demand-side technologies and practices, potential cost reductions for demand-side resources in the future, non-energy benefits (e.g., improvements in comfort, indoor air quality, productivity), up-to-date avoided costs, and maximum achievable adoption rates based on best practices by leading jurisdictions.

IRP modelers can run a variety of scenarios to capture a full range of demand-side resource estimates based on the potential study. For example, Ameren Missouri conducted a comprehensive DSM market potential study in April 2023 to inform its 2023 IRP. The study employed a methodology to account for interactions among DSM measures, load flexibility analysis, and scenario analysis. The utility benchmarked results of the study against comparable utility programs to ensure consistency with industry expectations (Ameren Missouri 2023a).

Both the load modifier approach and competitive resource approach are susceptible to bias with respect to measure adoption rates. If IRP modelers or market potential study analysts use overly conservative rates for measure adoption or measure adoption growth, savings results will be lower than can be supported by studies.[26] Customer paybacks for demand-side investments, non-energy impacts, and customer knowledge and awareness of technologies and programs (supported by the utility's customer outreach and marketing) may substantially influence customer decisions to implement DSM measures. Market potential study developers and IRP modelers would ensure results from the study are realistically

[26] For example, see TVA's 2015 IRP, which uses low adoption rate assumptions (Synapse 2015), pp. 10 to 15.

implementable by internalizing customer adoption rates that reflect customer economics and assumed program interventions (e.g., rebates, financing, customer outreach).

Best practice includes developing and using varying adoption rates for demand-side resources, including the maximum achievable adoption scenario based on aggressive historical savings achievements by leading jurisdictions and favorable policy and program scenarios (e.g., paying for 100 percent of the measure cost–comparable to treatment of supply-side resource costs, comprehensive customer outreach, and marketing and financing programs). A case in point is the NWPCC's approach to estimating total achievable potential for the regional power plan. NWPCC assumes that total cumulative market penetration rates increase to 65 percent, then 85 percent of the total technical potential over a 20-year timeframe (LBNL 2021d). Best practice for the competitive resource approach is for IRP modelers to produce a capacity expansion model run that offers savings up to those consistent with the measure adoption rates in the maximum achievable scenario in the most recent market potential study. Best practice for the load modifier approach is to include a maximum achievable scenario in the market potential study, as DTE did in its 2019 study by using "high" and "low" adoption scenarios (DTE 2019).

Policy considerations also need attention. For example, if certain energy efficiency investments for low-income households are required, the IRP model needs to select these investments regardless of the cost and consider them as a fixed input. In addition, some jurisdictions have minimum savings or budget targets for other market segments (e.g., small commercial customers) that are set by policy or regulation. While these targets could create suboptimal resource selection results, IRP modelers can strive to model these mandates as accurately as possible in at least one IRP scenario. States such as Washington require all cost-effective conservation to be procured (subject to a rate cap), regardless of the market segment. Utilities can model some of these requirements with a load modifier approach or simply by requiring the model to select these resources, while treating remaining conservation and demand response measures through a competitive resource approach.

## Best Practice 20. Model and bundle demand-side resources carefully

*If utilizing the competitive resource approach, model and bundle demand-side resources carefully to closely reflect actual program implementation and evaluation practices.*

Under the competitive resource approach, demand-side resources are grouped together in a manageable number of bundles as inputs to the capacity expansion model. IRP modelers can develop these bundles to reflect how energy efficiency and demand response programs are typically designed, implemented, and evaluated for cost-effectiveness. Some programs (e.g., home retrofit) contain multiple measures from low cost (e.g., lighting) to high cost (e.g., HVAC) in order to meet customer needs and avoid "cream skimming" that targets only the most cost-effective measures and abandons others often offered with them as a package. IRP modelers also need to model specific market segments carefully so that the modeling approach closely resembles actual program implementation practices.

Carefully bundling energy efficiency and demand response measures[27] avoids unnecessary computational complexity within a capacity expansion model. Modeling energy efficiency and demand response at the measure level and allowing the model to select individual measures based on costs, for example, may prevent the model from solving. Current practices for measure bundling include aggregation by cost (e.g., NWPCC, PacifiCorp) and load shape (e.g., Indiana Michigan Power). For example, Indiana Michigan Power divides the bundled energy efficiency measures in 5-year increments and annual 1,000 MWh units to reduce modeling time (IMP 2022).

When creating bundles for demand-side resources, planners can ensure that the temporal sequence of expenditures is realistic and relatively smooth, without large changes over time. Without such guardrails, the model may select considerably different amounts of demand-side resources each year. This may fail to capture realistic patterns of consistent program offerings or follow actual program design and administrative practices for stable or gradually increasing program efforts and funding.

Another best practice is to allow the model to select bundles less frequently than annually. Modelers also can ensure that costs for continued programs and new programs are different. Given first-year start-up costs, existing programs should produce a smoother output and are more likely to be selected in subsequent years. This is easily achieved by bundling measures based on whether they are new or existing and assigning bundle costs accordingly.

An example of this approach is Duke Energy Indiana's 2022 IRP. Duke Energy Indiana modeled a study period from 2021 to 2050. It represented its DSM savings with increased granularity in the near term and consistent with its DSM planning cycles: 2021–2023 and 2024–2026. The IRP grouped subsequent savings in 8-year periods from 2027–2034, 2035–2042, and 2043–2050. During the period 2021–2023, the model was required to select the bundle that corresponded with the utility's currently approved demand-side management portfolio as well as low-income program savings. The model could then choose an "expanded measure" bundle, an "expanded measure + higher avoided cost" bundle, or no bundle. The expanded measure scenario included current and newly proposed measures, as well as new energy efficiency programs where measures included in the study did not logically fit into an existing offering. A bundle with higher avoided costs further enhanced savings by increasing participation, increasing measures offered, or doing both. While Duke Energy Indiana did not model all potential scenarios developed through the market potential study, the utility chose which scenarios to model through collaboration with its Demand-Side Management Oversight Board. The utility aimed to implement several best practices, including offering bundles of savings in excess of those achieved under existing programs and constructing near-term bundles in a way that mimics their procurement through a 3-year DSM cycle.

Some state requirements call for cost-effectiveness of energy efficiency programs to be determined at the program or portfolio level (NESP DSP n.d.). Modelers can produce program-level bundles that reflect a few key programs that are complemented by measure-level bundles. However, demand-side resource choices made by the capacity expansion model do not translate directly to optimal program design; rather, those choices should inform the amount, market segment, location, and type of demand-side

[27] Bundling should be done separately for demand response and energy efficiency and measures. Demand response measures are oriented to capacity savings, while energy efficiency is mostly oriented towards energy savings (although it provides capacity contributions as well).

resource to procure. This is consistent with supply-side model outcomes that select generic resources but leave the specifics to CPCN, siting and permitting, and procurement processes.

## Best Practice 21. Ensure consistency with IRP scenarios

*Ensure consistency between demand-side resource assumptions and IRP scenarios.*

A key IRP principle is to represent the potential of energy efficiency, demand response, and other demand-side resources in a way that is consistent with the scenarios modeled in IRP. That is because assumptions made for IRP scenarios, such as those related to electrification and other load growth, also affect the potential for peak load reduction, load-shifting, and energy savings. This consistency is particularly important in the load modifier approach to DSM modeling because potential studies are typically developed before and in isolation from IRP modeling exercises. The competitive resource approach can produce more internally consistent portfolio choices, although consistency in basic cost and technology assumptions to characterize load and demand-side resource is important.

Aligning key assumptions (especially avoided costs and underlying load forecasts) in the demand-side resources potential study with assumptions in the IRP can mitigate distortions in modeling energy efficiency and demand response in IRP. A utility can conduct the potential study at the same time as, or right before, the IRP process and ensure consistency of key assumptions. Stakeholders need sufficient time and resources to participate in both the potential study and IRP processes, if they are conducted separately. If timing of the potential study does not allow for seamless coordination with the IRP, the potential studies can include sensitivities on avoided cost and load forecast assumptions. The utility, with stakeholder engagement, can select results from the sensitivity or scenario analyses that fit best with IRP modeling assumptions or outputs.

### Looking Ahead: Co developed scenarios for IRPs and market potential studies

Ideally, a set of scenarios would be developed ahead of both the IRP and the market potential study to be used in both; however, this is an aspirational practice with implementation challenges.

## Best Practice 22. Incorporate all relevant benefits for demand-side resources

*If using the competitive resource approach, incorporate all relevant benefits for demand-side resources by following policy objectives and requirements for assessing their cost-effectiveness.*

To fairly value demand-side resources, IRP modelers need to incorporate all utility system benefits as well as non-utility benefits that are consistent with all applicable policy objectives. Modeling demand-side resources dynamically in a capacity expansion model is not sufficient because the model typically captures only the benefits of avoiding energy and generation capacity and, when modeled, transmission capacity. However, demand-side resources provide other utility system benefits such as avoided transmission capacity (when not explicitly modeled), avoided distribution capacity, and risk management/hedging, as well as societal benefits such as avoided greenhouse gas emissions and other pollutants.

When a jurisdiction requires consideration of customer and societal benefits (e.g., reducing water usage and greenhouse gases, improving air quality) in cost-effectiveness screening tests to evaluate the benefits of demand-side programs, IRP modelers need to incorporate such non-utility benefits when screening cost-effective demand-side resources (LBNL 2021d). This is one of the principles of the *National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources*, which recommends inclusion of all benefits and costs to achieve policy objectives (NESP 2020). For example, in its regional power plan modeling the NWPCC incorporates avoided T&D costs in the form of credits that reduce the cost of energy efficiency measures. The NWPCC also incorporates non-utility benefits (e.g., water and O&M cost savings) when modeling energy efficiency in its capacity expansion model (LBNL 2021d). Incorporation of non-utility benefits is consistent with traditional qualitative discussions of supply-side portfolios that have environmental, financial, and other benefits.

Competitive resource approaches can leverage some avoided costs that are endogenously modeled in the IRP process, such as transmission costs or emissions costs. The load modifier approach typically cannot internalize these costs directly in the IRP, instead using externally produced avoided cost studies. Planners can verify consistency between assumptions used to develop avoided cost studies and those used in the current IRP and adjust avoided costs accordingly.

### MARKET INPUTS

Utilities commonly rely on market purchases to meet a portion of their energy and capacity needs. Utilities that model themselves as an island–that is, model their utility footprint as if it is not connected to external markets or energy sources–are not accurately reflecting their position in the larger electricity grid and are omitting market resources from consideration. Market resources, both energy and capacity, can frequently lower utility portfolio costs and impact resource selection. Reliance on market purchases, however, requires that utilities study regional resource adequacy conditions to ensure the market can be relied upon to supply energy and capacity needs (PSE 2021; LBNL 2019b). This regional awareness can inform design of scenarios for capacity expansion modeling.

## Best Practice 23. Use reasonable market interaction assumptions

*Model reasonable levels of market purchases that capture the benefits from market integration without exposing the utility system to risky levels of market exposure.*

Aligning capacity expansion modeling with regional resource availability is particularly important because factors such as load growth, growth of variable energy resources, and coal plant retirements affect available capacity. Utilities can provide transparency into treatment of market purchases in their modeling by describing their market studies and justifying the level of market purchases determined to be available for selection by the capacity expansion model.

Modeling a utility footprint as an island simplifies the modeling exercise, but it does not accurately capture potential lower resource costs, including market revenue potential. This tends to disadvantage zero marginal-cost resources such as solar and wind, which the utility can sell in the market. This approach can also disadvantage energy storage, which can store power from the market during hours of low cost for use when costs of supply-side resources are high. These values and revenues streams impact the economics of resource build decisions. Accurate representation of external markets allows the model to see the benefits from market interaction and impacts the model's resource selection decisions.

On the flip side, high reliance on the market requires proper justification. Detailed regional and market risk studies are best practice, but they are also resource-intensive. If the utility is unable to perform a full study or chooses to rely on simplified approaches to market interactions instead of a full study, it can align modeling assumptions with available transmission studies, recent market performance, and other external studies and projections of resource availability in the region.

Puget Sound Energy's 2021 IRP illustrates the importance of assessing regional energy and capacity availability (PSE 2021). The utility historically assumed that 1,500 MW of firm transmission capacity from the Mid-Columbia market hub would provide the utility with the equivalent to 1,500 MW generation capacity available to meet demand. In the past, Puget Sound Energy relied on this assumption to procure less generation capacity and lower its system costs. By 2021, however, three regional organizations had published studies indicating that the Pacific Northwest would transition from a capacity surplus into a shortfall at some point in the following decade without additional resource buildout.[28] In response, the utility decided to conduct a market risk and resource adequacy assessment for the 2021 IRP.

By aligning its resource adequacy model with regional reliability models, Puget Sound Energy was able to "translate the regional load curtailments forecasted […] into PSE-level impacts"(PSE 2021). Results showed that in some simulations, the availability of market purchases could be limited by 500 MW by January 2027. By that date, the utility might only be able to fill 1,000 MW of the available 1,500 MW of transmission (PSE 2021, chap. 7). The market risk assessment further analyzed recent market supply and demand fundamentals. Results showed that trading volume in the day-ahead market had declined 70 percent since 2015, while price volatility had increased. Increases in market volatility were particularly evident when high temperature events aligned with fossil fuel supply constraints at key power units (PSE 2021, chap. 7). This assessment resulted in Puget Sound Energy's decision to limit the number of market purchases going forward and transition short-term market purchases from a 1,500 MW limit to 500 MW. To fulfill its resource adequacy needs, the utility designed its preferred portfolio to reflect additional firm capacity contracts (PSE 2021).

### Fuel and commodity inputs

Widespread extreme weather events have shown that fossil-fuel-based units whose fuel supply is not properly winterized are subject to outages during winter weather events. In Winter Storm Uri, for

[28] These included NWPCC, Pacific Northwest Utilities Conference Committee, and Bonneville Power Administration. See (PSE 2015) Appendix G.

example, as much as 6.7 GW of thermal generation capacity was unavailable due to “fuel limitations”(UT Austin 2021).

Resource adequacy assessments performed as part of the IRP process typically do not capture the weather dependence of fuel availability. Even more concerning, the assessment rarely captures such common mode failures, when an underlying event causes a series of correlated outages across certain technologies.

## Best Practice 24. Model fuel supply limitations

*Incorporate fuel supply limitations, weather-sensitive failures rates, and weatherization investments in resource planning.*

Two related best practices improve IRP characterization of fuel availability for fossil fuel resources during extreme events, in line with utilities' continued focus on the impact of weather on the performance of solar, wind, and storage. First, as discussed in Best Practice 4, utilities (and ISO/RTOs) can develop and implement weather-sensitive failure rates that allow for highly correlated asset failures due to fuel availability. Second, in conducting IRP processes, utilities can plan for and model investments in winterizing fuel supply to reduce the common-mode failure rate for fossil fuel resources. These investments require careful analysis to ensure that further investment in the plant for winterization is economically optimal based on the forward-going economics of the plant relative to alternatives. A review of recent resource plans shows a focus on the impact of weather on the performance of solar, wind, and storage without enough focus on the weather impacts on other resource types, including coal and gas plants (LBNL 2023a).

The impacts of fuel supply limitations are another key factor for utilities to carefully consider in resource build or buy decisions. For example, Georgia Power Company recently filed an IRP update requesting approval to build three peaking combustion turbines (GPC 2023). The utility does not have a firm source of natural gas for the proposed plants and plans to operate them on oil during times when gas is not available. Oil is significantly more expensive than gas and has higher pollution levels across multiple emission types. Reliance on oil at the plant means the project will have higher costs and environmental impacts than a combustion turbine unit operated just on gas. Further, if the company faces natural gas constraints in the future, beyond what it assumes in the model, its reliance on oil will increase and so will the associated cost and environmental impacts.

## Best Practice 25. Evaluate the impacts of gas price volatility and coal supply constraints

*Incorporate fuel price volatility and fuel supply constraints into resource planning, and consider resource-portfolio solutions to limit risk.*

Fuel price volatility is a fact of the market and not something that individual utilities can control. High natural gas prices are straightforward to model, but volatility is much more challenging to capture through deterministic modeling. To incorporate fuel price volatility in electricity system modeling, utilities can use stochastic risk analyses that use Monte Carlo simulation to evaluate portfolio performance under different commodity price scenarios.

Utilities can take measures to manage and mitigate price volatility through various fuel procurement strategies—for example, through hedging programs that lock in a portion of supply at known costs to avoid the risk of high costs in the future. But hedging can be costly and, ultimately, a utility has more control over its resource supply mix than its fuel supply. By diversifying its resource mix and reducing the portion of its system that relies on the volatile input, a utility can control its fuel price volatility risk. Specifically, utilities can manage the portion of generation that comes from natural gas in each resource portfolio and design and model scenarios that limit the portion of a utility's portfolio subject to price volatility. This means focusing energy resource procurement on energy resources such as solar and wind that do not require fossil fuel inputs.

Price volatility and uncertainty has historically been most common in the gas market, but it has also been present in coal markets in recent years due to several factors. First, challenges stemming from labor strikes at both mines and the railroad transportation network resulted in price spikes in some parts of the country, particularly the Midwest and Appalachian region (Energy Ventures Analysis 2022; U.S. EIA 2023b). Some coal plants had to reduce operations due to low coal supply. There is likely to be more price uncertainty and possibly increasing prices in the future as more coal plants close, demand for coal drops, smaller coal suppliers go out of business, and the coal supply chain continues to contract. With more market power, the remaining large coal producers will have more control over coal supply, likely driving up the cost of coal in the future. Stochastic analysis and modeling of various coal price forecasts can help capture this risk. In addition, utilities can limit their exposure to these risks by reducing operations at, and planning for retirement of, coal plants.

### Transmission inputs

The IRP process provides crucial inputs for regional transmission planning. In May 2024, FERC issued a Final Rule (Order 1920) that provides guidance for transmission planners on transmission planning and cost allocation issues (FERC 2024). The order requires regional transmission planners to identify transmission needs driven by changes in power supply and demand by developing long-term scenarios at least 20 years long—a timescale that matches the typical IRP planning horizon. Likewise, FERC noted the need for proactive planning for resources not yet in development, so that planners can prioritize the most cost-effective solutions.

## Best Practice 26. Consider transmission alternatives and infrastructure expansion

*Consider transmission alternatives and expansion of regional transmission infrastructure as part of the resource planning process.*

To prioritize transmission solutions, transmission planners look to IRPs for long-term forecasts of supply-side resources that are most likely to materialize. In turn, utilities can incorporate information from these long-range transmission plans into IRP scenarios and allow endogenous transmission builds in capacity expansion models (where modeling capabilities allow). This best practice informs regional transmission planning and helps co-optimize transmission expansion and generation portfolio development. This is already occurring to some extent, and new modeling capabilities may support further effort in the future.

The primary driver for regional transmission expansion is the changing mix of generation resources that utilities are selecting. Regional transmission planning organizations including NorthernGrid and WestConnect build their regional transmission plans in a bottom-up manner using individual utility inputs (Gridworks 2023). In California, the reference IRP prepared by CPUC staff directly provides inputs for CAISO's Transmission Planning Process (CPUC 2023). Some large utilities such as PacifiCorp consider regional-scale transmission within the IRP. It's common even for smaller utilities to consider intra-system transmission upgrades in the IRP. However, these are typically in the form of hardcoded, preplanned transmission projects, rather than allowing the model to select transmission to help meet resource needs. The absence of wider exploration of transmission expansion and transmission optimization in IRPs are barriers to regional transmission buildout (Gridworks 2023).

A critical improvement is enabling capacity expansion models to select transmission buildout via tranches of transmission available at different costs. Modelers can also run scenarios that enlarge intrastate or regional connections to see how such changes shape optimized utility resource portfolios and costs. Doing so creates two benefits: (1) the utility is better prepared for a future with greater regional transmission planning and buildout, and (2) the utility can generate information that helps shape regional planning by informing regional planners about how different transmission options fit into a least-cost portfolio.

Some utilities already explicitly perform resource planning in a way intended to inform transmission planning. As PacifiCorp's 2023 IRP notes, "IRP and transmission planning processes complement each other by helping PacifiCorp optimize the timing of its transmission and resource investments to deliver cost-effective and reliable energy to our customers." The IRP included several large, preplanned, hardcoded transmission projects and endogenous selection of transmission to inform the relationship between "probable near-term projects and their transmission dependencies." Endogenous transmission capabilities specifically included "new incremental transmission options tied to resource selections, existing transmission rights tied to the use of post-retirement brownfield sites, incorporation of costs associated with these transmission options, and transmission options that interact with multiple or complex elements of the IRP transmission topology"(PacifiCorp 2023). As another example, Public Service Company of Colorado incorporated a section in its Clean Energy Plan that analyzed the necessary transmission investments to support its Preferred Plan, acknowledging the substantial transmission grid support investments required to interconnect a large portfolio of increasingly spread-out generation resources and accommodate generation retirements (PSCo 2021).

## Best Practice 27. Properly justify bulk power system interconnection costs and constraints

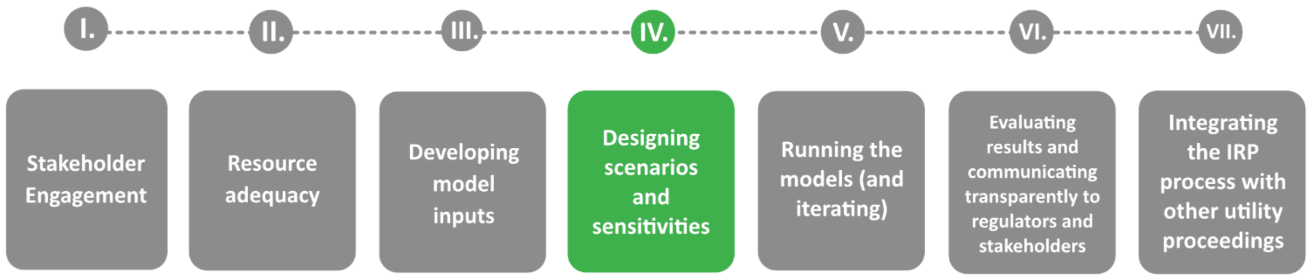
*Properly justify interconnection costs and constraints modeled for new generation resources at the bulk power system level.*

Ideally, transmission planning is integrated with generation planning. Transmission resources can be made available to the IRP model to select endogenously in the same manner as supply- and demand-side resources. For reasons discussed above, it is not always feasible or possible to fully integrate transmission planning into capacity expansion modeling based on model limitations, computing limitations, and a lack of full information on transmission expansion options. As an alternative, utilities sometimes estimate incremental transmission interconnection costs and attribute them to specific generation projects in the capacity expansion model. Even where interconnection capacity is constrained, utilities can model interconnection costs representative of the cost of addressing the constraints rather than omitting generation resources.

Given recent sharp growth in the total cost of interconnection-related network upgrades and the cost of such upgrades relative to generation project costs, it is best practice for utilities to factor interconnection costs into a project's capital costs. According to one report (Grid Strategies 2021) interconnection costs for new renewable resources were less than 10 percent of total generation project costs until a few years ago. Recently interconnection costs have risen to between 50 percent and 100 percent of total generation project costs as penetration of renewable energy resources on the grid increases.

Although reform is underway at both national and regional scales to change how costs are allocated, interconnection charges are still generally borne by the energy project developer. Utilities can ensure that the interconnection costs they model in IRPs are properly justified based on robust studies. Interconnection costs beyond the near term can reflect improvements in the interconnection process that are already underway. Additionally, interconnection costs can be applied fairly across all resource types to avoid bias in resource selection. Proper modeling and representation of interconnection costs will remain an important issue as additional transmission upgrades are increasingly needed to accommodate interconnection of resources on the bulk power system.

# IV. Designing scenarios and sensitivities




## Definitions

A **scenario** is a model run with a specific set of input assumptions and constraints—internal and external—to provide insights on distinct questions. Often, scenarios represent different goals or views of the future. Scenario A, for example, may include a high gas price forecast and low renewable energy capital costs, whereas Scenario B may include a low gas price forecast and high renewable energy capital costs. In this example, both scenarios serve as bookends at opposite ends of two scales. This is a common method for structuring scenarios.

A **sensitivity** is a model run that changes a single key input to understand how that input affects or drives results, often across multiple scenarios. The objective of a sensitivity analysis is to understand how results are affected by a single variable. For example, a higher load forecast may be applied to Scenarios A and B to test the effect of that one change layered across the range of other variables represented by each scenario.

A **portfolio** is the resulting resource mix from each scenario or sensitivity analysis, or a particular set of resources programed into a scenario to test. An optimized portfolio represents the least-cost solution to a capacity expansion model for a given scenario, considering risk and uncertainty.

Scenarios are the foundation of resource plan development and the framework for the model's optimization runs. Because utilities cannot evaluate every potential system outcome, they use scenarios to focus on inputs that are most likely to vary in the future and organize them around views of the likely future, specific policy goals, or other priorities. Modelers feed inputs and constraints for each scenario in the optimization engine (capacity expansion model) to produce a distinct optimized resource portfolio for each scenario. They then feed the resulting resource mixes into the production cost model to produce the optimized operational and dispatch plans for each scenario. The goal is for the utility to model a representative number of scenarios that provide sufficient information to inform the development of a preferred portfolio.

*Sensitivity* analysis enables a utility to understand how a change in a single input or constraint impacts its optimal resource mix. There are two general types of sensitivities: (1) a sensitivity that tests how the optimal resource mix changes assuming the utility plans for a change in one assumption from the start and (2) a sensitivity that performs a "robustness check" on a specific portfolio to quantify the operational and cost risks of an inaccurate single assumption. Both types of sensitivities are important, and both can help inform a utility resource plan.

For example, if the utility wants to understand how a higher gas price forecast will impact its resource mix, it re-runs the capacity expansion model using a high gas price forecast. The results will tell the utility how to plan its system if it thinks that gas prices are likely to rise (or even just become increasingly volatile). Alternatively, if the utility is interested in understanding the risks or robustness of each portfolio to high gas prices, modelers can run all of the portfolios through a new production cost modeling run with a high gas price forecast. The results will reveal how system operations and costs will change for each scenario if the system is built assuming base gas prices, but then gas prices are much higher.

Planners face several challenges to designing effective IRP scenarios and sensitivities, including the following:

1. *Modeling a full, comprehensive range of uncertainties vs. producing straightforward, informative results.* Too many scenarios, with too much complexity, risk confusing stakeholders. But too few scenarios risk omitting evaluation of critical factors.
2. *Balancing stakeholder requests with utility priorities and commission requirements.* Utilities can reduce the number of scenarios they have to run by designing scenarios that satisfy the priorities of multiple parties where interests overlap.
3. *Minimizing shareholder risks vs. minimizing ratepayer costs. The interests of utility shareholders and ratepayers do not always align.* That can drive utilities to model specific scenarios and omit others that could be lower cost or lower risk. For example, a utility may not model early retirement of an aging fossil fuel generator with a large undepreciated balance because that creates shareholder risk.

All these challenges require common sense, an open mind, and prudent judgment. This chapter offers best practices for exercising these qualities when building scenarios, evaluating scenarios, and using scenario results.

## Best Practice 28. Model a base case that allows for easy comparison

*Model a base case scenario that facilitates comparison across scenarios and sensitivities and ensure internal consistency across all scenarios and sensitivities.*

Utilities include multiple scenarios in their IRPs to test a range of future outcomes. To ensure a useful comparison across all of these scenarios, a best practice is to first develop a base scenario as the starting point for all other scenarios. Modelers can use this base scenario to ensure they design all subsequent scenarios and sensitivities to be internally consistent so that results can be readily compared across scenario and sensitivities. Any subsequent scenarios can be designed to deviate from the base in a clear and methodical manner—i.e., with different loads, commodity prices, regulatory assumptions, new resource cost assumptions, and more.

Best practice is to design the base scenario to reflect a realistic view of the world—i.e., an "expected" scenario—and abide by all existing federal, state, and regulatory requirements. Where there is regulatory uncertainty about the future of a final regulation, utilities can model a range of scenarios both with and without the regulation (as discussed in Best Practice 30).

Where a utility is modeling both its own footprint and the larger market the utility operates in, it is also important that assumptions be applied consistently across geographic scales (except where deviations are intentional). For example, it is critical to align input assumptions, such as commodity and market prices, regulatory assumptions, and resource cost inputs, across geographic scales.

Consistency across scenarios is also important. A high decarbonization scenario, for example, is likely to result in lower market energy prices in many hours of the year due to the higher prevalence of zero-marginal-cost resources, but also higher prices in some hours. If the utility does not develop its own scenario-specific market prices, it can select a third-party market price forecast that reflects the utility's assumptions about the relationship between decarbonization in its footprint relative to decarbonization in the rest of the market. A lower energy market price may reflect the assumption that decarbonization is happening across all regions, while a base or high market price may reflect the assumption that decarbonization is happening more rapidly in the utility's footprint than in the broader market region.

It is also important for utilities to use the results of sensitivities and scenarios thoughtfully in drawing conclusions. Revenue requirement results can be most easily compared across portfolios developed using the same fundamental price forecasts for commodities (e.g., gas, coal), electricity market prices, emissions, loads, new resource costs, regulatory context, and other consistent inputs. Comparing costs across portfolios developed with different fundamental inputs can be used to understand risk and uncertainty, but not to draw direct conclusions about which portfolio is least-cost.

## Best Practice 29. Design scenarios to evaluate uncertainty and risk

*Design a range of scenarios that provide information about uncertainty and risk across a range of futures.*

The objective of scenario development is to understand uncertainty and risk in the electricity system and determine how to best manage them through resource planning. Scenarios focus on evaluating and understanding likely future views of the world (and the electricity system), the impact of specific policy goals on resource planning, how market trends could impact resource options, and how risk and uncertainty around various inputs and variables impact the optimal resource mix. Some scenarios may focus on isolating the impact of a few specific variables. Others help the utility understand what type of full system changes are necessary to meet a specific goal. Ideally, all of the scenarios modeled meet existing state and regulatory requirements and represent reasonable stakeholder priorities.

Table 1 identifies common uncertainties and risks that IRP scenarios address, with examples. Best practice is to focus on developing scenarios that evaluate real and likely variables and futures. Scenarios that evaluate extreme themes or views of the world may be interesting, but ultimately are not likely to provide useful information for resource planning purposes.

*Table 1. Common uncertainties and risks that IRP scenarios address, with examples*

| Uncertainties and Risks | Examples |
|---|---|
| **High electrification** | Dominion Energy South Carolina 2023 – high electrification scenario (Dominion SC 2023) |
| **High DER and DSM future** | Dominion Energy South Carolina 2023 – high DSM scenario (Dominion SC 2023) |
| **Technology advancement (CCS, hydrogen, small modular reactors)** | Tucson Electric Power 2023 – P09 Portfolio with Small Modular Reactors (TEP 2023a) |
| **Long-duration storage** | Public Service Company of New Mexico 2023 – long-duration storage scenario (PNM 2023) |
| **Decarbonization by a certain year** | Xcel Energy Upper Midwest 2024 – 100 percent carbon-free by 2050, Avista 2023 – Clean Portfolio by 2045 (Xcel Energy 2024; Avista 2023) |
| **No new fossil resources after a certain year** | Avista 2023 – no new natural gas, Santee Cooper 2023 – no new fossil generation (Avista 2023; Santee Cooper 2023) |
| **Retirement of all fossil fuel plants by a certain date** | PacifiCorp 2023 – retire all coal plants by year-end 2029, retire all natural gas plants by year-end 2039 (PacifiCorp 2023) |
| **Compliance with proposed environmental regulations (e.g., Clean Air Act section 111(d) rule for greenhouse gas emissions)** | Xcel Upper Midwest 2024 – environmental policy scenario (Xcel Energy 2024) |
| **Increased environmental regulation** | Dominion Energy South Carolina 2023 – aggressive regulation scenario (Dominion SC 2023) |
| **Extreme weather** | PacifiCorp 2023 – extreme weather load forecast sensitivity (PacifiCorp 2023) |
| **Change in reliability requirement or reserve margin** | Public Service Company of New Mexico 2023, Avista 2023, Xcel Energy Upper Midwest 2024 (PNM 2023; Avista 2023; Xcel Energy 2024) |
| **Increased industrial and data center loads** | Xcel Energy Upper Midwest 2024 – data center load sensitivity (Xcel Energy 2024) |
| **Increased transmission buildout** | PacifiCorp 2023 – All Gateway scenario (PacifiCorp 2023) |
| **Stakeholder-requested scenarios** | Public Service Company of New Mexico 2023, Avista 2023, PacifiCorp 2023, DTE Electric Company 2022, Duke Energy Indiana 2021 (PNM 2023; Avista 2023; PacifiCorp 2023; DTE 2022; DEI 2021) |
| **Commission-mandated scenarios** | Public Service Company of New Mexico 2023 – impacts of a range of carbon prices (PNM 2023) |

Sometimes it makes sense to combine multiple uncertainties and risks in a single portfolio to test a scenario with a complete view of the future. Other times it makes sense to isolate and test particular changes in sensitivities. Transparency is key, for scenarios and sensitivities as well as the utility's preferred portfolio.

## Best Practice 30. Plan for and incorporate important regulatory factors

*Model all final, proposed, and likely regulations to allow time for proactive planning and identification of no-regrets actions.*

Regulatory uncertainty is a particularly impactful uncertainty for planners to account for in scenario analysis. This can take the form of final rules that are being legally challenged, formally proposed rules, or even regulations that are likely but not yet proposed.

For example, NREL's annual Standard Scenarios report accounts for regulatory uncertainty in its U.S. electricity sector outlook by modeling all scenarios under current policies, as well as under two national electricity sector carbon dioxide emissions constraints: one that reaches 95 percent net decarbonization by 2050 and another that reaches 100 percent net decarbonization by 2035 (NREL 2023). Reference scenarios that only include current policies may serve as a point of comparison for other scenarios and provide insight on the risk of the status quo, but do not represent the expected future.

For final regulations that are new or subject to legal challenge, some utilities choose to model compliance as a single alternative scenario rather than as part of a base scenario. Modeling compliance as just a single sensitivity or alternate scenario and not in the base case limits the utility's ability to plan for a future with the regulation in place and identify no-regrets actions that are economic regardless of the regulation's status.

Proposed policies and regulations provide valuable insight into the direction of regulatory momentum and can give utilities the opportunity to figure out how to model new and complex requirements. When it comes to environmental regulations in particular, failing to model any further regulation prior to a finalized rule nearly guarantees that capacity expansion modeling misrepresents the future by underestimating environmental compliance costs. Future regulations are inherently uncertain, but modeling current or pending regulations is a better central case than assuming no future regulation. For example, EV deployment targets aimed at decarbonizing transportation will very likely grow as low-cost EVs become more readily available and charging infrastructure becomes more prevalent. Environmental regulations of emissions related to air and water will almost certainly continue to increase in stringency and call for lower levels over time, even if there is temporary backsliding. Modeling scenarios and sensitivities that examine the impacts of regulatory factors such as these provides insights into how the utility's strategy would need to respond to changes to rules and makes resource plans more responsive to potential

> ***Such modeling can also help the utility understand which resource options are most robust or less risky regardless of future regulations, and which are highly sensitive to regulatory outcomes. Crucially, these scenarios and sensitivities can also inform the utility's preferred portfolio.***

changes. Such modeling can also help the utility understand which resource options are most robust or less risky regardless of future regulations, and which are highly sensitive to regulatory outcomes. Crucially, these scenarios and sensitivities can also inform the utility's preferred portfolio.

It is common for utilities to reject modeling regulations that are not yet finalized, with the justification that prior to finalization, uncertainty surrounding the rule is too great for incorporation into planning. Utilities also may avoid modeling final rules that are being formally challenged in legal venues. For instance, Avista's 2023 IRP acknowledges the impact of draft rules that EPA issued in May 2023 relating to coal- and natural-gas-fired resources, but states that no adjustments will be made to the resource plan prior to issuance of final rules (Avista 2023). Duke Energy's 2023 IRP for North and South Carolina devotes a chapter to "Planning for a Changing Energy Landscape," noting the rapid advancement of policy-driven financial incentives, such as clean-energy-related tax credits under the *Infrastructure Investment and Jobs Act* and IRA, as well as new environmental regulations such as EPA's proposed *Clean Air Act* Section 111 rule for greenhouse gas emissions. Duke evaluated the performance of its Core Portfolios and Supplemental Portfolios under conditions of the proposed 111 rule for "informational purposes" (Duke Energy Carolinas 2023, chap. 2). Although Duke's modeling shows that the proposed rule may have important planning ramifications, the utility did not include the proposed rule in its base planning assumptions because it is "still being interpreted, clarified, and commented on and may change prior to being finalized" (Duke Energy Carolinas 2023, chap. 3). Similarly, Dominion Energy in Virginia and Santee Cooper in South Carolina did not consider the proposed rules in their recent IRPs (Dominion VA 2023; Santee Cooper 2023).

EPA's proposed Greenhouse Gas Regulations under Section 111 of the *Clean Air Act* is an example of how a proposed environmental rule can provide an advanced look at the direction of a final rule. The proposed rule included a variety of compliance measures including the option to comply through CCS, hydrogen conversion, co-firing with natural gas, or lowering capacity factors. Although the final rule, published in 2024, altered some specific aspects of the rule and removed the hydrogen conversion compliance option, the basic structure of the regulation, its stringency, and ramifications for highly-polluting power units—namely, reductions in carbon dioxide emissions—were largely unchanged. Studying the impact of the proposed rule would have provided an advanced look at the risk of continued reliance on regulated units, particularly those that pollute the most.

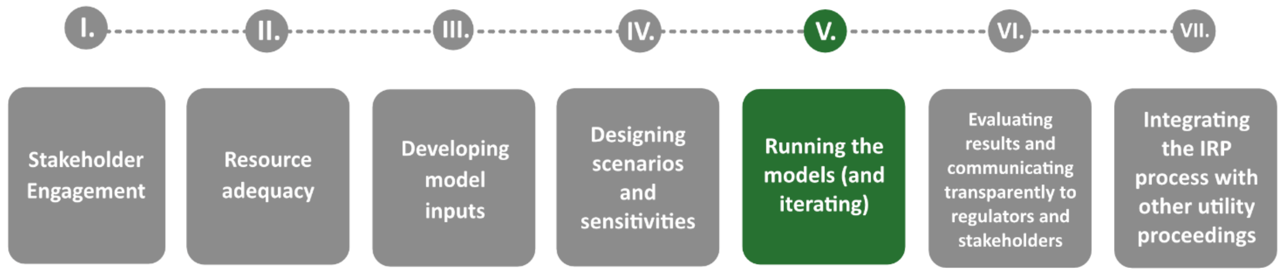
Modeling the impact of proposed regulations can also inform intelligent regulatory design. When EPA publishes new environmental rules, the agency solicits feedback from industry. Incorporating proposed environmental regulations into IRPs can provide quantitative evidence to support industry feedback.

For example, Duke's modeling of the proposed 111 rule shows that although the Core Scenarios are "generally in line" with the first phase of the proposed 111 rule, compliance paths through later phases produce dramatically different results from the Core Scenario, with striking cost impacts. One tested path would require an additional 1.6 GW of offshore wind and an additional gas combustion turbine by 2035, both of which exceed Duke's forecast for resource availability and add $3.9 billion to the sensitivity's present value of revenue requirements (PVRR). Another path relies on hydrogen blending and increases the PVRR through 2050 by $11.4 billion. While these changes indicate that EPA's proposed 111 rule has the potential to change the least-cost system for Duke, the utility did not factor the sensitivities into its preferred resource plan.[29] This creates a risk that the utility's plan will be rendered suboptimal by EPA's final 111 rule.

Best IRP practice is to take a reasonable and considered view of expected future regulations and include them in the base case scenario. Where there is significant uncertainty, planners can analyze alternative futures with more and less strict regulations in other scenarios or sensitivity analyses, or both. Assuming environmental regulations that are not finalized will not exist in the future can lead to costly resource decisions and delays in resource planning and resource procurement decisions.

[29] Duke notes a variety of near-term (2023–2026) actions to study hydrogen availability; but it otherwise does not incorporate the proposed 111 rule into its planning, aside from stating that it will update its planning assumptions as new requirements evolve (Duke Energy Carolinas 2023, chap. 4).

# V. Running the models (and iterating)




This section of the report presents nine best practices relating to selecting, initializing, calibrating, and running the various models used in the IRP process.

## Best Practice 31. Thoughtfully select capacity expansion and production cost models

*Thoughtfully select capacity expansion and production cost models and use modeling software that can perform both functions if possible.*

Capacity expansion and production cost models offer two complementary perspectives on the costs of the power system. While the industry trend has been attempting to integrate these models, software still tends to be specialized. A best practice is to verify the outcomes of a capacity expansion model using a more accurate and detailed production cost model in an iterative process.

Historically, some utilities relied on models that only have production cost capabilities. Instead of letting the model develop an optimized portfolio, utilities manually develop and test specific scenarios. This approach is inefficient, imprecise, and unlikely to lead to a least-cost outcome. Another best practice is selecting modeling software that can perform both capacity expansion and production cost functions.

A small number of commercially available models are typically used by utilities for capacity expansion and production cost optimization in IRPs, such as EnCompass, Aurora, and Plexos (Yes Energy, n.d. EnCompass; Energy Exemplar, n.d.-a Aurora; n.d.-b Plexos). That is in part because few models have adequate capabilities; have been used widely enough for utilities, regulators, and stakeholders to trust the results;[30] and offer sophisticated and consistent customer service to address the myriad of issues that using these models entail (including access to prepared and curated datasets). Expanding the pool of available models could help lower barriers to accessing modeling capabilities. National laboratories have developed several well vetted open-source models such as ReEDS (NREL ReEDS n.d.-c) and RPM (NREL RPM n.d.-d) capacity expansion models and the Sienna production cost model (NREL Sienna n.d.-e), among others (MIT and Princeton GenX n.d.; PyPSA, n.d.; RAEL SWITCH n.d.). These open-source

[30] This creates a barrier to entry for new models. A model must be trusted in order to be widely used, and it must be commonly enough used to be trusted.

models have limitations in their user base, support, and user interface that would need to be addressed before being fully viable alternatives.

Capacity expansion and production cost models developed and maintained by third parties such as commercial vendors and government agencies are important because they are accessible at least in theory by any stakeholder. That means results can be replicated and models remain relatively unbiased in their design. Open access to datasets also is critical for result replication. In practice, stakeholder access to models can be challenging due to the cost of model licensing,[31] the technical sophistication required for users, concerns about data confidentiality, and some utilities' ambivalence about collaborating with stakeholders at this level (see Section I on stakeholder engagement for more information).

### Looking Ahead: Benchmark models to support IRP best practices

To support adoption of best practices in resource planning, utilities would benefit from third-party benchmarking of models—comparing them in terms of performance and outcomes.*

Different models emphasize certain characteristics of the power system over others. For example, they differ in the temporal resolution used to capture operational and investment timeframes. Some models use a time slice approach that emphasizes energy and ancillary service needs; other models use a sample hour approach that emphasizes capacity needs. Ideally, a third party would compare existing models to inform choices to represent the utility-specific power system analyzed in the IRP.

Model assessments would ideally go beyond comparing model attributes to help resource planners choose and implement a suite of models. Challenges with this approach include the proprietary nature of datasets and the time required to set up and run models. A common standard for data inputs could allow for a manageable yet informative number of redundant simulations to verify key decisions.

While model performance is important, other considerations for model selection include transparency, usability, and vendor support (see DTE Electric Company's Integrated Resource Plan Modeling Software Collaborative Summary Report in MPSC Case No. U-20471)(DTE 2020).

* *The Energy Modeling Forum compares energy and climate models, but to our knowledge, no one has systematically compared and validated models used for utility IRP* (Stanford University).

## Best Practice 32. Thoughtfully select a geographic model scale

*Thoughtfully select a geographic model scale that allows meaningful analysis of the resource potential and diversity available to the utility system being planned.*

There is an inevitable tradeoff between model complexity and performance. This tradeoff is especially relevant to IRP modeling, which can include hundreds of runs to simulate a wide range of scenarios and sensitivities. The more complex the model, the longer the run time. That will limit how many model runs planners can complete within a given timeframe.

[31] In some states, regulators have required utilities to purchase model licenses for intervenors, as in Arizona and Iowa.

Two key aspects characterize model complexity: spatial scales and temporal scales. The spatial scale relates to the level of topological and geographical detail used to represent the power system under study. The temporal scale relates to the time-sensitive granularity of the system's operation as well as the time horizon for investment decisions. Thoughtful choices for spatial and temporal scales—with consideration for their interactions—balance accuracy and tractability (see Best Practice 33 and Best Practice 34).

Key spatial decisions include the choice between zonal and nodal modeling,[32] modeling of integration with regional markets, modeling of transmission connections and limits, and modeling of the utility footprint within the larger region and any relevant ISO/RTO to capture regional impacts on reliability and resource mix (for example, how much can the utility rely on the market).

While nodal modeling is most accurate, zonal is much less computationally- and data-intensive and likely sufficient from a resource planning perspective. Regional market integration can be reflected through a one- or two-step process. For the one-step option, the utility uses full capacity expansion and production cost modeling for the utility's footprint as part of the larger ISO/RTO or region it sits within. For the more common two-step option, the utility first runs the capacity expansion model for the full region to produce market prices, with relaxed constraints for resource builds and unit dispatch.[33] Then, in a second step, the utility uses market prices as an input to model the utility footprint with more granular settings and constraints for both capacity expansion and production cost runs (see Best Practice 40). While full regional modeling is more accurate, it is unlikely to be computationally viable for production cost modeling. At the same time, modeling the utility as an island without regional connections is not a reasonable IRP practice.

Regional modeling requires a scale that reflects geographic diversity in renewable resources and load characteristics. Modeling choices for supply- and demand-side resources are influenced by how their temporal profiles interact and by their location. A best practice is to study historical load and variable renewable energy generation patterns and then establish a minimum set of zones that are explicitly reflected in the model to capture diversity in these patterns. Reliability and resource constraints and parameters are critical model inputs.

Generally, transmission planning is integrated with resource planning processes, but through different modeling exercises. To simulate major transmission connections and limits in a zonal model, planners can create distinct zones for each region. An appropriate spatial scale will reasonably represent transmission corridors—in particular, lines that are typically congested—so the model can more accurately consider transmission lines for expansion (see Best Practice 26III.Best Practice 26). Planners usually choose higher voltage lines (i.e., above 220 kV) and several key substations to capture system topology. In addition, planners will want to consider including nodes that have historically presented patterns in locational marginal prices that reflect congestion, regardless of the nodes' voltage levels.

[32] Nodal modeling refers to using actual transmission substations and the transmission grid topology to locate load within the model. Zonal models aggregate substations and associated transmission lines and connected load into contiguous zones that simplify the model.

[33] Market price forecasts are dependent upon specific assumptions for gas prices, regulations, policies, and resource deployment within the ISO/RTO footprint.

## Best Practice 33. Thoughtfully define the appropriate study period

*Use a study period that is long enough to allow meaningful comparison between capital-intensive resources and others that might be considered and built in the future.*

The temporal scale for IRPs works at two levels: investment and operation. Capacity expansion and production cost models interact across these scales to ensure rigorously tested least-cost outcomes. With respect to investment temporal scales—the IRP planning horizon—the minimum planning period may be defined by statute or regulation. As a general best practice, the study period extends far enough into the future to include important differences between scenarios with respect to recovery of investment costs and avoid distortions, as discussed below.

Any optimization that is done for a finite modeling period (e.g., 5 years or 20 years) has the potential to be influenced by "end effects," meaning significant costs that would be incurred beyond the study period. This issue has been recognized since the late 1970s. Proposed solutions include adding a salvage value to any asset and liability or approximating the system's continued operation (UC Berkeley 1979; Murphy and Soyster 1986). In many instances this is not a significant problem, particularly if the study period is long and the investment scenarios do not have large capital investments whose cost recovery would occur beyond the end year. On the other hand, in cases where there are large investments made near the end of the modeling period, considering and accounting for "end effects" can be quite important.

Typically, planners compare scenarios based on their PVRR (or cumulative discounted costs) over the study period. For example, if a capital-intensive project is brought online near the end of the planning period in one resource scenario but not in another, then the cost comparison between the scenarios may not reflect the real cost differences between the cases. Planners might address this issue by extending the study period a few more years or by making an "end effects" adjustment to the scenario costs.

In addition to issues regarding the overall length of the study period and accounting for potential costs that would be incurred beyond the study period, some optimization modeling assumes "perfect foresight." The model optimizes the entire study period as each if year's capacity expansion and retirement decisions can be made with knowledge of future loads, fuel costs, capacity additions, etc. For a particular year, the model assumes future regulatory costs, which can be used to inform near-term decisions. This can be desirable in some instances, but if there is a high level of uncertainty around decisions far into the future, it may be less desirable to have uncertain information drive near-term decisions. In addition, because some optimization models consider more information in making decisions, a long optimization period can also result in long model runtime. Conversely, single-year or multi-year foresight/optimization reduces the model run time, can help space out new builds, and can exclude uncertain drivers from near-term consideration.

The choice of optimization horizon can be especially important for resources expected to have declining costs over time, as with the significant annual capital cost reductions for some renewable and storage resources. In such cases, the optimization algorithm of a least-cost model might delay as much as possible capital-intensive decisions in ways that would not reflect appropriate decision-making. Most models today solve the problem by annualizing investments, applying useful lifetimes, and internalizing these annuities in the objective function. This practice, coupled with using an extended modeling horizon, should prevent end-effect distortions.

## Best Practice 34. Thoughtfully select the appropriate time granularity for production cost modeling

*Use a time granularity for the production costing simulation that enables modeling of important timing considerations in dispatch.*

In addition to the time horizon over which the model makes investment decisions, the resolution or granularity of the dispatch for operation costs is also a critical modeling parameter decision. A best practice for operational temporal scales for both production cost modeling and capacity expansion modeling is using hourly representation, consistent with resource adequacy assessments. Hourly scales enable single-day or even multiple-day chronological representation for system operation that captures some ancillary services needs, such as ramping requirements. Intra-hour analysis that includes primary and secondary frequency, voltage regulation, and other non-economic simulations may be conducted as well in suitable power flow, dynamic, and reliability models.

Full 8,760-hour representations for annual system operation are generally tractable. However, in cases where the spatial scale needs to be highly granular, the complexity of the simulation may increase substantially. In these cases, modelers can use a subset of hours that reflect peak and non-peak hours and seasonality of loads and resources. Ideally, modelers will choose this subset of hours carefully and, when possible, capture consecutive 24-hour periods and even longer timeframes for modeling long-duration storage. While less common in capacity expansion models, many utilities use 8,760-hour representations in production cost models and similar portfolio refinement steps, as demonstrated in several 2023 IRPs (Santee Cooper 2023; PacifiCorp 2023; Avista 2023).

## Best Practice 35. Calibrate the production cost and capacity expansion models

*Calibrate the production cost and capacity expansion models to anchor them to current system conditions and validate the legitimacy and accuracy of the model results.*

Capacity expansion modeling is an inherently theoretical exercise that studies possible evolutions of a power system based on initial conditions and forecasts of key variables. Nevertheless, the model still needs to be anchored in, and calibrated to, current system conditions. The calibration process may be time-intensive and iterative, but it is necessary for the legitimacy and accuracy of models and results.

A best practice is to ensure that the dispatch, dynamics, and prices/costs from the production cost model match those seen in the current power system. For utility-scale modeling, this may include ensuring capacity factors for each simulated unit and technology class are consistent with recent dispatch outcomes, and that the production cost model reflects reasonably well overall system costs.

For larger regional modeling, metrics for calibration may include matching total generation by resource type and zone to capture both technology-level production and spatial distribution. In some cases, matching by individual unit may be possible and necessary to appropriately reflect transmission flows. In any case, planners will need to carefully analyze the import and export profiles in the production cost model output, particularly if the dispatch in neighboring areas is also being simulated, rather than as serving as an input to the model. Puget Sound Energy's 2021 IRP provides an example of such simulation (PSE 2021). Import and export profiles would ideally approximate the seasonal and daily patterns so that the model adequately reflects the surpluses and deficits of power within the planning entity footprint.

In this calibration process, the utility would evaluate its model inputs, make adjustments, and iterate until the model delivers results that more closely match reality. Planners might want to use some level of discretion to avoid overfitting the models, since this may introduce distortions into the production cost model or capacity expansion model that could affect results. For example, trying to closely match winter dispatch conditions for certain resources may induce large distortions in assumed summer operation for the same resources. In addition, actual utility decisions may be driven by factors that the model does not consider, such as risk aversion, sunk costs, or political environment—and hence planners will want to account for these when analyzing model fit against operational data.

## Best Practice 36. Let optimization models optimize

*Let optimization models optimize resource additions and retirements as a complement to modeling specific retirement scenarios.*

The concept of optimization—a process aimed at developing the "best" path that balances tradeoffs, costs, and benefits—sits at the core of IRP modeling. Capacity expansion models are founded on the principle that optimizing for least cost should drive resource builds and retirements. A best practice is to limit unnecessary constraints on the model and allow the model to do what it was designed to do: optimize. The results from optimization model runs provide important information on the best way to balance system costs, needs, and constraints.

Planners can program many aspects of capacity expansion and production cost modeling into the model, including:

1. *System constraints.* These include reserve margins, emission programs, transmission capacity limits, regional import and export limits, reserve and ancillary service requirements, and any other parameters that cover the entire utility system.
2. *Load and demand.* System load and system peak demand.
3. *Resource input assumptions*. These include resource costs, operational characteristics (ramp rates, heat rates), capacity accreditation, shapes (for variable energy resources), outage rates and schedules, and other resource inputs.
4. *Commodity costs.* Examples include fuel costs and carbon prices.

These parameters require programing into the model because capacity expansion and production cost models are not designed to endogenously make decisions about most system constraints and resource inputs. The modeler is responsible for selecting reference values for each input and varying them manually through different scenarios and sensitivities as necessary. Some of these inputs can and should be determined by exercises outside of the core resource planning modeling—for example, the reserve margin and resource capacity accreditation.

There are also key decisions where it is best *not* to hardcode and constrain across resource planning exercises. These are decisions that a capacity expansion model makes endogenously by design, mainly:

1. Resource build decisions
2. Resource retirement decisions

There are legitimate reasons why a utility also may design certain scenarios with specific resource build and retirement decisions programed in, instead of relying solely on an optimized scenario. Such considerations include computational limits, regulatory deadlines, policy requirements, settlement agreements, just energy transition, and many others. Additionally, the remaining life of a resource radically changes plant investment, which can be challenging to accurately and dynamically capture in the model.

Putting aside near-term decisions that are already locked in, a starting point and default best practice is to optimize resource retirement decisions, rather than hardcode them based on utility preference or a decision the utility already made. For example, this frees the model to reveal whether a different retirement date, in the context of all other model parameters, assumptions, and resource alternatives, yields a more desirable solution. The practice of overly constraining IRP modeling through hardcoding retirement dates is very common in utility IRPs. This is driven in part by the outage and capital upgrade cycles for existing fossil plants, such as coal plants. To accommodate these cycles, some utilities, such as Duke Energy Carolinas, conduct separate retirement analyses to develop coal unit retirement dates that they then hardcode into the capacity expansion models. While the external studies provided useful information, the utility did not integrate these retirement analyses with modeling the rest of the electricity system, preventing the model from finding a truly optimal solution.

Likewise, when it comes to new resource builds, capacity expansion models work best when free to choose from among all currently available resource types (and even some emerging ones over the longer term) and free to build what is needed to meet load (subject to system constraints and regulations) in each year. That includes both supply- and demand-side resources, as well as transmission expansion options. Capacity expansion models by design evaluate continued operations versus retirement and replacement with alternatives, but the models can only do this if they are unconstrained in doing so.

Again, there may be value in testing portfolios that lock in retirement or resource build decisions or place reasonable limits on those decisions. Still, best practice is to conduct unconstrained optimization runs for retirement or resource build decisions and include an optimized modeling run with the utility's preferred portfolio. Locking in resource addition and retirement decisions for scenarios and sensitivities may be appropriate after robust modeling is performed to provide clear reasoning and support resource decisions with evidence.

Other modeling constraints may be useful—when testing high and low ranges of uncertain values, evaluating specific unit retirement dates, and seeking to limit the problem size and computing requirements. Supply chain interruptions or interconnection queue constraints, for example, may warrant setting a maximum annual build cap on a given resource type. In such cases, best practice is to be transparent about setting the cap, limit the timeframe for applying it, and provide a well-reasoned explanation. Best practice is to also run scenarios without any caps to determine whether there is a better solution if deployment barriers can be overcome. Further, it is essential for the utility to recognize that such a cap is a modeling construct, and that the market and other on-the-ground realities represent the actual limits to procurement.

***A model can only act on information given and can only make the choices it is allowed to make. Using an optimization model is therefore only a first step, not a replacement for critical thinking.***

While a utility's preferred portfolio may deviate from the optimized portfolio, it is essential for the utility and regulator to understand the economically optimal results, especially in planning near-term procurement activities. For example, if an optimized scenario shows it is most economic to add 3 GW of solar PV in 2028 to replace a retiring resource, this finding can be used for developing RFPs and communicating to the market that the utility is going to be looking to procure as much solar as it can economically get by 2028, even if there are legitimate reasons for the preferred portfolio as modeled to stagger that resource addition over multiple years.

Limits to optimization models are important to keep in mind in implementing best practices for model optimization. Any model reflects a simplified version of reality. An optimization model, for example, will show planners the lowest-cost resource plan based on selected inputs. It will not tell them which alternative plan could be even lower cost if the planner used different modeling assumptions or inputs. Best practice includes testing a wide enough range of reasonable scenarios that build off optimized results to capture a comprehensive range of possible future conditions. A model can only act on information given and can only make the choices it is allowed to make. Using an optimization model is therefore only a first step, not a replacement for critical thinking.

## Best Practice 37. Base power plant retirement decisions on forward-looking costs

*Base power plant retirement decisions on forward-looking costs, not sunk costs or cost recovery concerns.*

Almost all utility assets have undepreciated plant balances. This is particularly true of legacy fossil fuel generators such as coal plants, which have both an existing plant balance from past investment and ongoing and future capital expenditures to maintain operations and comply with environmental regulations. Existing plant balances are sunk costs that are unavoidable with retirement.[34] Sunk costs do not provide relevant information for resource planning decisions. On the other hand, O&M and fuel costs, as well as ongoing capital expenditures which become part of a plant’s undepreciated balance once they are incurred, *are* avoidable with retirement (as discussed in Best Practice 16). In IRP modeling, planners must differentiate between sunk costs and avoidable future costs to accurately assess resource

[34] A variety of regulatory mechanisms, including accelerated depreciation, can help address sunk costs for plants the utility plans to retire.

retirement decisions. Avoidable future costs can only be considered by an IRP model in selecting a retirement date if they are included in the model.

There are three pieces to retirement analysis: *whether* a plant should be retired, *when* it should be retired—including the optimal retirement date, and *how* any remaining balance should be treated in rates after retirement. The IRP process, through capacity expansion modeling, addresses the first piece and part of the second piece.

The determination of *whether* to retire a unit is based on a unit's expected forward-going economic performance and all expected forward-going costs, including sustaining capital expenditures, environmental capital expenditures, and fixed O&M. Best practice is for a utility to ramp down investment in a plant in the years leading up to retirement and include those assumptions in capacity expansion modeling. Ideally, when a unit is expected to become uneconomic on a forward-going basis, planners prioritize it for retirement to avoid incurring additional costs and operational losses that would be passed on to utility customers. Again, sunk costs are *not* considered in the IRP process.

Capacity expansion modeling can identify a unit's economically optimal retirement date. But the decision of *when* to retire a unit also needs to consider the timeline for procuring replacement resources, as well as *how* the utility will handle sunk costs. These decisions typically occur outside IRP processes. Specifically, procurement, cost recovery, and cost allocation decisions are typically addressed in other proceedings. Aligning resource planning modeling with resource planning decisions made outside of the IRP process is important and is discussed in Section VII in this report.

## Best Practice 38. Use modeling parameters that capture the value of battery energy storage

*Use modeling chronology and parameters that capture the full value that BESS can provide to the grid and accurately capture charging and discharging cycles.*

Appropriate capacity expansion modeling capabilities and methodologies are critical for simulating high-renewable electric grids, particularly those that include battery storage of varying durations. The model chronology used in the long-term capacity expansion component is particularly important. Capacity optimization models have long relied on a simulation chronology that optimizes resource builds based on a subset of representative days. That might be some number of days distributed across the entire year, one on-/off-peak day per month, or a typical week per month. Such sampling methods fail to capture the variability in variable renewable energy generation, and storage charging and discharging, across longer time scales. Thus, these methods fail to accurately value the flexibility that long-duration storage resources can provide. To capture the ability of these resources to shift energy across days, weeks, and seasons, it is essential to optimize resource builds using a modeled chronology of 8,760 hours.

Sampled modeling chronologies often fail to capture multi-day lulls in renewable energy generation as they occur both within and across years. They therefore do not consider the implications of such events on resource builds, grid reliability, and energy prices. The magnitude of these lulls will only increase as electric supply shifts toward even greater penetrations of renewable resources. It is critical that utility resource planning include scenarios that capture these lulls as well as other periods of grid stress.

Similarly, best practice in modeling long-duration storage resources requires modeling storage build and dispatch over multiple weather-years and including weather-years with extreme conditions that lead to periods of grid stress. Industry-standard modeling often builds an optimized resource mix designed to meet the annual peak load, with an established reserve margin, under typical weather conditions. However, weather varies from year to year, and that variance can have substantial impacts on energy system requirements. A resource portfolio built around average weather conditions might not meet system resource adequacy standards in a weather-year that includes one or more grid stress periods. Modeling a single weather-year also tends to underestimate the flexibility benefits of long-duration storage resources. Best practice modeling optimizes resource builds over multiple weather-years to produce a resource portfolio that is more robust against weather variability, though we are unaware of any utility that has incorporated this practice into its capacity expansion modeling.

Storage resources are characterized by power discharge capacity as well as energy storage capacity. Most IRP models simplify the representation of storage by prescribing its duration, either with a single value (e.g., 4-hour storage) or modeling storage resources in cohorts of discrete, fixed durations. For example, Portland General Electric's 2023 Clean Energy Plan/IRP modeled six lithium-ion battery durations, ranging from 2 to 24 hours, as well as a 10-hour pumped-storage hydro resource (PGE 2023). This approach simplifies the optimization process and might be the best that utilities can do with commercially available capacity expansion models. But it can miss identifying system needs that could be met with specific durations of storage located at specific points in the system. Best practice would treat power discharge capacity and energy storage capacity as two independent variables, such that the optimal solution ultimately defines the designs for the storage resources needed.

Further, IRP best practice would simulate fully dispatching storage resources with explicit representation of charging and discharging cycles. The 2023 PacifiCorp Clean Energy Plan/IRP describes endogenously modeling dispatched storage resources according to their roundtrip efficiency and other operational constraints (PacifiCorp 2023). The 2023 Tucson Electric Power IRP includes an example of the hourly battery dispatch in its production cost model (TEP 2023a). Accurate modeling of real-world operational conditions for these units requires comparison of sample charge-discharge cycles to empirical profiles. A related practice involves appropriate modeling of different types of long-duration storage—multi-day, multi-week, and seasonal storage units. For more details on best practices for modeling long-duration storage in IRP, see Best Practice 17.

## Best Practice 39. Use stochastic approaches for robust portfolio creation

*Use stochastic modeling approaches to produce portfolios that are robust to changes in inputs.*

A key challenge in IRP is assessing the risk that stems from the array of uncertain inputs to the exercise. Load location and growth, weather, fuel prices, variable renewable energy production, asset outages, capital cost reductions, policies, and regulations are all uncertain. Two key risks that arise from these uncertainties and need assessment are (1) whether the preferred portfolio remains a least-cost option within reasonable variation of inputs, and (2) whether the resulting system is resource-adequate when exposed to varying load, weather, and resource availability. As reported in Section II in this report, properly developed resource adequacy assessments use stochastic modeling to represent the likelihood of shortfalls in the bulk power system and address the second point. This best practice expands on the first point.

Conventional capacity expansion modeling in IRP is a deterministic analysis. Planners input deterministic forecasts for uncertain variables exogenously, and the model optimizes based on these pre-set values. As discussed in Section IV of this report, running scenarios and sensitivities is the traditional approach to managing uncertainty in least-cost or economic decision-making. These mechanisms are easy to understand, but their interpretation is qualitative, and there is no reassurance that the portfolio decisions stemming from these qualitative assessments are optimal (see Best Practice 41).

Capacity expansion models have the capability to run with stochastic inputs, providing tools to test the impacts of uncertainty, although uptake from planners has been slow. Examples of utilities that use stochastic inputs include AES Indiana's 2019 IRP. The utility employed a stochastic capacity expansion model that reflected fuel price volatility and correlation to produce multiple portfolios (AES Indiana 2019). A more common alternative is to use a stochastic approach to test the distribution of costs of preferred portfolios by running a production cost model of the portfolio with stochastic inputs. In contrast to running the capacity expansion model with stochastic inputs, this approach uses stochastic variable costs to recalculate production costs for deterministically defined portfolios. In CenterPoint Indiana's 2023 IRP, for example, the utility performed a stochastic risk assessment to compare portfolios. The stochastic inputs used in these risk assessments included natural gas prices, coal prices, carbon prices, peak loads, and capital costs for renewable energy resources (CenterPoint Energy 2023). TVA, PacifiCorp, AES Indiana, Puget Sound Energy, Idaho Power, and DTE also have recently used this approach. Entities such as PacifiCorp, the NWPCC, and TVA with a substantial amount of hydropower resources in their analyses have traditionally used stochastic representation of hydrological variability in production cost modeling, as well as developing related sensitivities in capacity expansion modeling (PacifiCorp 2023; Northwest Council 2022; TVA 2019).

These best practices produce multiple portfolios based on stochastic inputs or assess the short-run economic performance of portfolios when input variables are stochastic.

### Looking Ahead: Use optimization algorithms in stochastic economic modeling

An aspirational practice in stochastic economic modeling would employ advanced robust optimization or chance-constrained optimization algorithms to ensure the distribution of outcomes falls within prescribed ranges given probabilistically defined inputs. These advanced algorithms produce a single preferred portfolio that is designed to be robust to changes in inputs. Inevitably, any best or aspirational practice to perform stochastic analysis in IRPs will substantially increase computational needs, runtime, and complexity.

Stochastic approaches to capacity expansion and production cost modeling do not entirely replace scenario-based analysis and sensitivities. Stochastic approaches are useful when the input variables can be modeled through rigorous probability distributions. However, several inputs to IRPs cannot be modeled like this, such as the likelihood of adoption of certain policies or predetermined retirement of certain assets, among others. Load growth, weather-driven parameters, fuel prices, capital costs, and similar quantitative variables are suitable for stochastic representation. Behavioral aspects that drive load and flexibility profiles are an emergent area of research for stochastic representation.

## Best Practice 40. Use the models iteratively

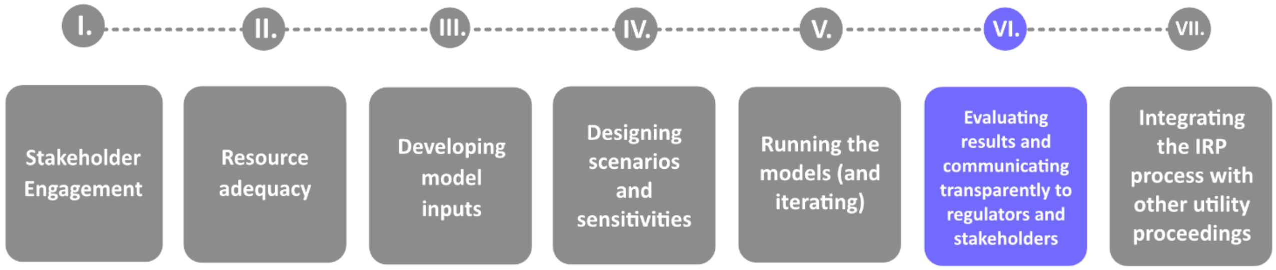
*Use capacity expansion and production cost models iteratively to help refine results.*

Capacity expansion and production costs models are best used iteratively in resource planning. Planners make necessary simplifications during the capacity expansion stage to decrease the problem size. Results from production cost modeling may reveal, for instance, that the capacity expansion model did not develop enough resources to provide ancillary services, omitted impacts of more detailed transmission systems, left unserved energy, or did not reflect well the contributions of variable resources such as wind, solar, and demand-side resources. For example, PacifiCorp found that portfolios developed in its initial capacity expansion model led to consistent capacity shortfalls when tested in a more granular dispatch model that explicitly accounted for operating reserve requirements (PacifiCorp 2023). Similarly, Public Service Company of Colorado found that the initial portfolio developed by the capacity expansion model was unable to satisfy reliability criteria (PSCo 2021).[35] In this case, using a supplemental resource adequacy modeling run identifies reliability shortfalls which can inform modifications for another set of capacity expansion runs.

An iterative approach to modeling is a best practice. Production cost runs help refine capacity expansion runs, and supplemental resource adequacy modeling sheds light on any reliability concerns. This produces more robust results and may allow the capacity expansion model to select and retire resources that minimize both long-term investment costs as well as short-term operational costs.

[35] Capacity expansion models are generally constrained by reserve margins. This approach generally ensures there is sufficient capacity to meet firm peak demand, but it does not answer questions about how a system will perform under extreme weather conditions, for example. Generally, separate stochastic reliability modeling is needed to answer such questions.

# VI. Evaluating results and communicating transparently to regulators and stakeholders




The following section discusses best practices for presenting results to regulators and stakeholders, as well as selecting a preferred portfolio.

## Best Practice 41. Use appropriate metrics to evaluate IRP results

*Use appropriate metrics that have been intentionally designed to avoid skewing results towards a predetermined outcome.*

After a utility has finalized its modeling results, the next step typically involves summarizing portfolio results in a matrix that presents utility performance across key metrics to facilitate comparison and communicate key differences across scenarios, often referred to as a scorecard. Scorecards can synthesize a large amount of information into a digestible format. In designing a scorecard, a best practice is for utilities to solicit feedback from stakeholders and regulators about the metrics included and whether the information is clear and unbiased.

Ideally, the process of selecting scorecard metrics would be an iterative process with stakeholder involvement. Utilities, regulators, and stakeholders can define core metrics at the outset of the IRP process that are aligned with region-specific needs and goals, such as pollutant emissions, rate impacts, customer satisfaction, economic development, and many others. Other important metrics can be added as the modeling progresses.

While there is no one-size-fits-all scorecard, there are common pitfalls to avoid. If a utility plans to use a weighting system to rank the relative importance of metrics, a pitfall to avoid is adjusting weights of metrics to reach a predetermined outcome. Instead, the utility can clearly communicate and justify the methodologies it uses for weighting, stakeholders can provide input, and regulators can review how weighting affects the selection of the utility's preferred portfolio.

In general, it is important to avoid using qualitative analyses that can be easily adjusted to preferentially highlight certain scenarios and thereby skew portfolio results. A good scorecard includes only those metrics that measure an explicit goal of the state, utility, or stakeholders, and excludes metrics that are already accurately reflected in PVRR results. All portfolios considered “should be safe and reliable, and to the extent that more or less system flexibility implies a cost, that cost should already (and accurately) be reflected in PVRR" (Synapse 2015). In addition, best practice is to avoid using extreme scenarios to skew portfolio rankings and the selection of the utility's preferred portfolio (for more information on preferred portfolio selection, see Best Practice 44 and Best Practice 45).

Following are examples of common metrics commonly included in a scorecard:

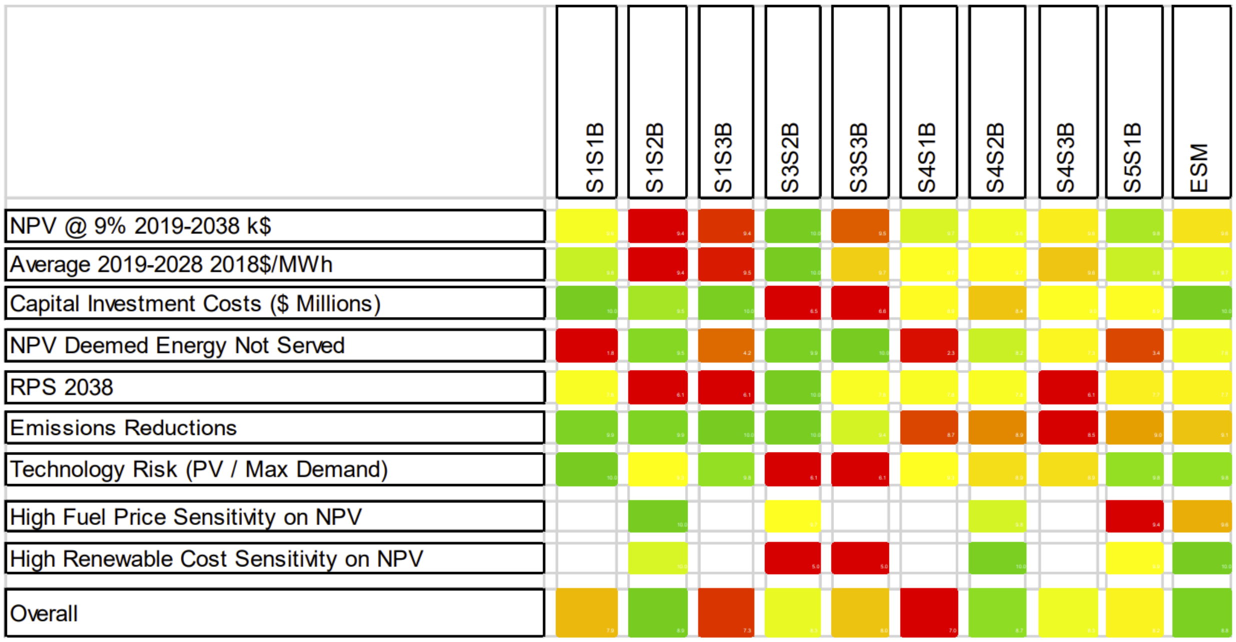
- **Cost.** Net PVRR over the short-term (5–10 year) and full study period (20 years or more), in absolute terms
- **Environmental sustainability.** Carbon emissions (total tons) and carbon intensity (tons per kWh), percent of generation from carbon-emitting resources vs. low carbon resources
- **Reliability.** If differentiated by portfolio, metrics could include LOLE and expected energy not served, among others that are relevant to the system being modeled
- **Cost exposure.** Exposure to fuel price volatility as measured by percent of generation provided by gas, coal, and oil plants
- **Market exposure.** Percent of load met through market purchases

The following examples highlight a scorecard that does not follow Best Practice 41, as well as a scorecard that does.

The Puerto Rico Electric Power Authority's (PREPA) 2018–2019 IRP scorecard does not follow best practice for clear presentation of results. The effort to create a qualitative, colorful scorecard resulted in a highly subjective, potentially biased, and confusing figure. The IRP explains that the scorecard (Figure 6) complements quantitative analysis of the PVRR of each scenario (Siemens Industry 2019). Elements that create room for misunderstanding include the following:

- Scenario names are not defined in the table or the text describing the figure, and the coded names provide insufficient summary information for each scenario.
- Metrics for each scenario are not clearly defined in the figure or descriptive text.
- Color-coding is not based on a defined or quantitative scale and obscures valuable information about the spread between and across variables.
- Weightings are not clearly defined, especially in relation to the "Overall" category and how it was calculated for each scenario.

*Figure 6. Scorecard for PREPA's 2018–2019 IRP*




*Source: Recreated from Siemens Industry. Puerto Rico Integrated Resource Plan 2018–2019, Exhibit 8-7. Prepared for Puerto Rico Electric Power Authority.*

The clearly presented scorecard in AES Indiana's 2022 IRP (see Figure 7) provides a good example of Best Practice 41.

*Figure 7. AES Indiana 2022 IRP scorecard results*

| | Affordability | Environmental Sustainability | | | | | | Reliability, Stability & Resiliency |
|---|---|---|---|---|---|---|---|---|
| | *20-yr PVRR* | *$CO_2$ Emissions* | *$SO_2$ Emissions* | *$NO_X$ Emissions* | *Water Use* | *Coal Combustion Products (CCP)* | *Clean Energy Progress* | *Reliability Score* |
| | Present Value of Revenue Requirements ($000,000) | Total portfolio CO2 Emissions (mmtons) | Total portfolio SO2 Emissions (tons) | Total portfolio NOx Emissions (tons) | Water Use (mmgal) | CCP (tons) | % Renewable Energy in 2032 | Composite score from Reliability Analysis |
| 1 | $ 9,572 | 101.9 | 64,991 | 45,605 | 36.7 | 6,611 | 45% | 7.95 |
| 2 | $ 9,330 | 72.5 | 13,513 | 22,146 | 7.9 | 1,417 | 55% | 7.95 |
| 3 | $ 9,773 | 88.1 | 45,544 | 42,042 | 26.7 | 4,813 | 52% | 7.86 |
| 4 | $ 9,618 | 79.5 | 25,649 | 24,932 | 15.0 | 2,700 | 48% | 7.90 |
| 5 | $ 9,711 | 69.8 | 25,383 | 24,881 | 14.8 | 2,676 | 64% | 7.57 |
| 6 | $ 9,262 | 76.1 | 18,622 | 25,645 | 10.9 | 1,970 | 54% | 7.95 |

| | Risk & Opportunity | | | | | | | Economic Impact | |
|---|---|---|---|---|---|---|---|---|---|
| | *Environmental Policy Opportunity* | *Environmental Policy Risk* | *General Cost Opportunity **Stochastic Analysis*** | *General Cost Risk **Stochastic Analysis*** | *Market Exposure* | *Renewable Capital Cost Opportunity (Low Cost)* | *Renewable Capital Cost Risk (High Cost)* | *Generation Employees (+/-)* | *Property Taxes* |
| | Lowest PVRR across policy scenarios ($000,000) | Highest PVRR across policy scenarios ($000,000) | P5 [Mean - P5] | P95 [P95 – Mean] | 20-year avg sales + purchases (GWh) | Portfolio PVRR w/ low renewable cost ($000,000) | Portfolio PVRR w/ high renewable cost ($000,000) | Total change in FTEs associated with generation 2023 - 2042 | Total amount of property tax paid from AES IN assets ($000,000) |
| 1 | $ 8,860 | $ 11,259 | $ 9,271 | $ 9,840 | 5,291 | $ 9,080 | $ 10,157 | 222 | $ 154 |
| 2 | $ 8,564 | $ 11,329 | $ 9,030 | $ 9,746 | 5,222 | $ 8,763 | $ 9,999 | 99 | $ 193 |
| 3 | $ 9,288 | $ 11,462 | $ 9,608 | $ 10,237 | 5,737 | $ 9,244 | $ 10,406 | 195 | $ 204 |
| 4 | $ 9,135 | $ 11,392 | $ 9,295 | $ 9,903 | 5,512 | $ 9,104 | $ 10,249 | 74 | $ 242 |
| 5 | $ 9,590 | $ 11,275 | $ 9,447 | $ 10,039 | 6,088 | $ 9,017 | $ 10,442 | 55 | $ 256 |
| 6 | $ 8,517 | $ 11,226 | $ 8,952 | $ 9,629 | 5,136 | $ 8,730 | $ 9,909 | 88 | $ 185 |

**Strategies**

1. No Early Retirement
2. Pete Conversion to Natural Gas (est. 2025)
3. One Pete Unit Retires in 2026
4. Both Pete Units Retire in 2026 and 2028
5. Clean Energy Strategy – Both Pete Units Retire and replaced with Renewables in 2026 and 2028
6. Encompass Optimization without Predefined Strategy

*Source: Recreated from AES Indiana 2022 Scorecard Results, Figure 9-78.*

AES Indiana based its evaluation categories (affordability; environmental sustainability; reliability, stability, and resiliency; risk and opportunity; and economic impact) on a set of pillars for electric utility service defined by a task force created by the Indiana General Assembly. This kind of intentional alignment with policy areas of interest helps ensure that the IRP is most informative for regulators (AES Indiana 2022). The scorecard clearly explains each category in detail in the text of the IRP and breaks it down into a set of quantitative metrics (e.g., PVRR, total portfolio carbon dioxide emissions). While the chart uses colors to indicate high and low values for each metric, it also includes quantitative values. In addition, the IRP immediately defines coded scenarios below the figure for stakeholder reference. The IRP also did not roll all metrics into a single score for each scenario, so there is no question of how weighting may slant results. While this eliminates one area of concern, it also puts the onus on AES Indiana to clearly explain why Strategy 2 was selected as the preferred portfolio rather than Strategy 5, which appears to result in similar outcomes overall.

## Best Practice 42. Report results clearly

*Ensure that modeling results are reported in a way that is transparent and easy to understand.*

Effective IRPs report results in a way that is transparent and easy to digest, with sufficient information for effective stakeholder engagement, review of modeling methodology and findings, and regulatory oversight. At the same time, providing too much unprocessed data without proper synthesis can challenge all but the most sophisticated stakeholders to understand and provide input. This applies to scorecard matrices, as well as informational results that are not necessarily being used to evaluate or rank scenarios. Some stakeholders may have technical expertise to review raw data, and some may even want access to raw modeling data. Nevertheless, it is critical for the utility to summarize and synthesize results so that all stakeholders and regulators can understand the inputs, modeling process, and final results. A good example of a utility clearly reporting results and providing key information is Tucson Electric Power's 2023 IRP Dashboard (TEP 2023b).

Best practice IRPs provide a narrative for each scenario, alongside the following public information on results, at a minimum:

- Summary load and resources table for each portfolio, by year, for the full study period. The table summarizes all existing capacity by resource type, all new resource additions by resource type, the utility's demand forecast, and total capacity requirement including reserve margin—both firm (accredited) capacity and nameplate capacity. The table also includes the utility's firm capacity assumptions, including ELCC, for all resources.
- Summary table of generation (GWh) and capacity factors (percent) for each portfolio. The table summarizes generation by resource type and year, broken down by existing and new resources.
- Capacity graphs. These figures display firm capacity, nameplate capacity, and generation by resource type and by year.
- Table of air emissions. The table includes greenhouse gases and criteria pollutants by year for each portfolio.
- Table of plant retirements. The table shows retirement dates modeled for existing resources and indicates whether the date was programmed in or selected endogenously by the model through optimization.
- Table of new resources. The table clearly shows the quantity of new resources coming online each year, by resource type, showing both firm (accredited) capacity and nameplate capacity.
- Cost. Net PVRR over the short-term (5–10 year) and full study period (20 years or more), in absolute terms. While providing PVRR delta results from the preferred portfolio may also be useful, providing the final PVRR by scenario helps stakeholders contextualize the magnitude of the deltas.

Utilities can avoid providing stakeholders with an overwhelming number of metrics or scenarios while at the same time not obscuring important data with simplistic graphics.

## Best Practice 43. Benchmark inputs and results to other utilities

*While developing input assumptions and analyzing results, utilities can look to see how inputs and results of neighboring or similar utilities compare to each other. If there are major differences, these need to be justified or explained to stakeholders.*

Over the next few years, dozens of utilities across the United States will produce and file IRP reports and annual updates. IRP practice could benefit immensely if utilities compared quantitative outcomes in their reports to provide data for benchmarks that stakeholders can use to assess appropriateness of IRP assumptions and results. Strong benchmarks require a large enough sample of utilities to serve as analogs that report customer number, peak demand, sales, and climate zone, among others, to produce normalized benchmark outputs. Examples of these quantitative outcomes include the expected percent of load growth for base and alternative scenarios, rates of adoption of renewable resources, speed of retirement of coal plants, and assumptions about resource costs and fuel prices. As part of its 2025 IRP process, Tennessee Valley Authority hired Deloitte to review the utility's 2019 IRP and conduct benchmarking of peer IRPs, including identifying key themes and trends to be considered in its current IRP (TVA 2024).

### Looking Ahead: Publish standardized planning metrics for easy comparison

In addition to benchmarking against key planning assumptions in a public repository such as the Resource Planning Portal, the jurisdiction's utilities, regulatory commission, and stakeholders can agree on sets of standardized metrics that enable efficient comparison of IRP inputs and outputs. There is no current best practice in this area; these guidelines are aspirational.

For example, calculating, recording, and comparing average annual load growth might facilitate assessment of the reasonableness of load forecasts across utilities under normal conditions. A metric such as MW-kilometer of transmission capacity per MW of solar power may be a way to assess and compare the costs of renewable energy integration and support a discussion on assumptions that may be biasing estimated costs upwards or downwards. Regulators could define a set of standardized metrics that could be used to benchmark IRPs and support rigorous quantitative analysis of assumptions, parameters, and outputs. Under this potential best practice, utilities with assumptions that reasonably deviate from the norm would need to justify the differences.

Wilkerson et al. (2014)recognized the benefits of benchmarking for IRP a decade ago when they analyzed and compared plans filed by 38 load-serving entities. However, the same paper identified multiple shortcomings and inconsistencies in the collection and reporting of planning assumptions. Lawrence Berkeley National Laboratory started to address this issue by designing and developing the Resource Planning Portal, an online publicly available tool to collect key quantitative planning assumptions from IRPs (LBNL Planning Portal n.d.-a). The portal collects and shares key inputs and outputs for each IRP's preferred portfolio. Lab researchers seek to standardize the way IRP inputs and outputs are defined and recorded. Parameters recorded include annual consumption and peak load forecasts, annual energy efficiency and demand response resources, fleets of existing and planned generation and storage units, fuel prices, capital costs, and carbon costs.

## Best Practice 44. Select a preferred portfolio

*Select a preferred portfolio to guide near-term actions and justify any substantial deviations from the optimized portfolio.*

Best practice IRPs identify a preferred portfolio, a collection of resource builds and retirements the utility selects based on one of the portfolios tested in the IRP process. The preferred portfolio reflects the utility's short- and long-term resource plan and serves as the basis of near-term procurement plans. A robust preferred portfolio is developed in the capacity expansion model and vetted comprehensively as part of the IRP process. Under this best practice, utilities avoid developing preferred portfolios outside the model or selecting a preferred portfolio that is a hybrid of multiple candidate portfolios at the end of the process—and not subject to the same level of sensitivity and risk analysis as other modeled portfolios. When the utility selects a preferred portfolio, it also is good practice to evaluate and explain any significant differences between optimized portfolios and the preferred portfolio. This is because the optimized portfolio is, by design, the least-cost portfolio for a scenario.

Traditionally, utilities select or design a preferred portfolio based on cost, as quantified by a portfolio's net PVRR. While net PVRR is a key pillar of scenario evaluation, and minimizing cost is important for utility customers, it is not the only differentiator between scenarios. Nor is it an automatic determinant of which examined portfolio the utility ought to select as the preferred portfolio. The portfolio may only appear least-cost in the context of the others the utility examined. If the modeling examined a narrow set of options, or used key inputs that were hardcoded, out of date, or poorly designed, the portfolio may not be the least-cost option available. Additionally, a portfolio may misleadingly appear least-cost because modeling did not fully capture and internalize associated risks and uncertainties (see Best Practice 29 and Best Practice 39).

Because the IRP process is tied to near-term procurement efforts, a preferred portfolio is essential to provide a clear short-term plan. If the utility does not select a preferred portfolio, it is likely not committing to a near-term procurement plan. Without a preferred portfolio, it is hard for stakeholders and regulators to focus their feedback and oversight. Considering the near-term action plan for resource procurement is an important part of the IRP review process. As discussed in Section VII of this report, IRP results can be important in other dockets, including in rate cases for determining cost recovery, in CPCN dockets for evaluating the reasonableness of new resource build proposals, in renewable portfolio standard compliance dockets for determining if resource plans meet state renewable energy requirements, and in fuel dockets for evaluating the reasonableness of utility fuel procurement and operational decisions.

The utility's selection of a preferred portfolio does not necessarily tie the utility to that portfolio, even in the short term, depending on how much and how quickly conditions change. But the preferred portfolio creates an important baseline for utility planning. The regulator may require the utility to justify changes to its resource plan, or why the plan has not changed if conditions shift markedly. Some states, such as Virginia (Virginia General Assembly, n.d.) and Oregon (Oregon 2021) require utilities to file IRP updates annually or when plans change significantly.

## Best Practice 45. Model state goals and priorities in the preferred portfolio

*Align the preferred portfolio with articulated state goals and priorities.*

It is common for regulators to require specific IRP elements. A typical example is requiring the utility to select a “preferred portfolio,” as discussed above. While the requirement to select a preferred portfolio does not prescribe resources that must be included, in many states, regulators require utilities to model specific scenarios and sensitivities to inform the preferred portfolio and make the results publicly available in a useful manner. Running mandated scenarios is not enough. The utility's modeling choices and presentation of results are critical for illuminating which factors affect planning costs and decisions.

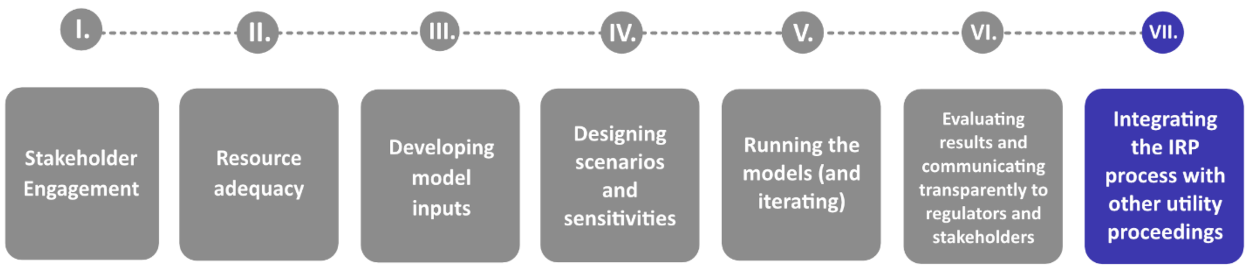
For example, the Arizona Corporation Commission required Arizona Public Service to run more than 10 specified scenarios for its 2023 IRP, including a minimal load growth scenario, rapid DSM adoption, and a variety of sensitivities that examined early retirement of the Four Corners coal power plant. While the utility followed through on this direction, some parties ultimately had concerns with how the utility designed and presented some of the scenarios—particularly the early coal plant retirement scenarios (Sierra Club 2024).

> ***Running mandated scenarios is not enough. The utility's modeling choices and presentation of results are critical for illuminating which factors affect planning costs and decisions.***

Arizona Public Service developed the required early retirement sensitivities by altering the retirement date of Four Corners in a reference case and then allowing the model to re-optimize. This method showed that early retirement in 2028, for example, would cost $139 million less than the reference case, which retired the plant in 2031. Separately, the utility designed a preferred portfolio, which maintains the 2031 retirement date but differs from the reference portfolio in other ways. Arizona Public Service concluded that this portfolio would be $357 million cheaper than the reference portfolio. The utility presented this information as evidence that the preferred portfolio would cost less than the portfolio representing the early retirement date.

Although Arizona Public Service followed the commission's direction in modeling additional scenarios, the scenarios differed in critical ways from the preferred portfolio. It is also unclear why the utility did not test earlier retirement dates for Four Corners using its preferred portfolio, not just the reference portfolio. Comparing an early retirement sensitivity in the reference portfolio to a 2031 retirement in the preferred portfolio is not an apples-to-apples comparison. In addition, since early retirement in the reference portfolio yielded lower costs, an early retirement sensitivity for the preferred portfolio also would have resulted in lower costs. Such analysis would have provided a full picture of potential cost savings across portfolios (Sierra Club 2024). In situations like these, regulators can scrutinize the scenarios modeled by the utility and request that the utility run additional scenarios that align with the commission’s original goals.

# VII. Integrating the IRP process with other utility proceedings




IRP scenario analysis requires careful design of modeling assumptions and possible pathways. It produces a wealth of useful data that has implications for the power system as a whole. Modeling assumptions that are intentionally prepared to easily port them into other modeling exercises have important consistency and transparency benefits. The following best practices apply to using IRP scenario results to inform other regulatory proceedings.

## Best Practice 46. Use IRP results to inform an Action Plan and utility procurement processes

*Integrate resource planning and related procurement processes.*

A primary purpose of IRP scenario results is to inform utility procurement processes. In practice, this translates to utilities using IRPs to support an RFP, CPCN, or other procurement process. The first step in this direction is for the IRP to include a well-designed Action Plan.

The Action Plan is a section in the IRP document that describes near-term actions the utility will take over the next 1 to 3 years related to implementing outcomes in the preferred portfolio. An effective Action Plan is supported by the results, analysis, and conclusions of the IRP. It clearly states the action the utility plans to undertake to procure resources, including issuing RFPs, securing any required CPCN, initiating siting and licensing process, and deploying or expanding energy efficiency and demand response programs (LBNL 2021c). The Action Plan outlines how the utility plans to comply with specific regulatory requirements (e.g., a renewable portfolio standard target for an upcoming year) and proposes any regulatory changes that may be needed to support the development and execution of the preferred portfolio. In cases where the IRP recommends a wait-and-see strategy for risk management, the Action Plan can include near-term milestones to pursue the strategy (e.g., in an IRP update report, describe progress on a certain component of the IRP that was deemed uncertain). Finally, the Action Plan can outline near-term actions the utility identified to improve its analytical capabilities, such as developing certain datasets, working with vendors to implement new tools, or collaborating with stakeholders to refine input assumptions. PacifiCorp's 2023 IRP provides an example of a clear Action Plan, using a table format to identify and organize near-term actions for specific units, projects, and regulatory requirements (PacifiCorp 2023).

A best practice for procurement is to use the same inputs and assumptions reviewed by regulators in the IRP process, unless there are significant changes in market conditions. In cases where the investment environment has changed from what the utility assumed in the most recently filed IRP, the utility can leverage scenario results to support departures from the preferred portfolio—given that scenarios are least-cost expansions of the bulk power system under different assumptions. If no existing scenarios match current investment conditions, the utility can conduct new scenario runs to support procurement decisions and ensure these procurement-specific scenarios inform the next IRP filing.

## Best Practice 47. Use IRP results to inform planning for bulk power systems

*Use IRP results to inform evolution of planning for bulk power systems and distribution systems.*

IRP scenario results offer a range of potential pathways for evolution of the bulk power system. Several other planning processes would benefit from information on these pathways:

- Planning for distributed energy resource programs and virtual power plants. Wholesale electricity prices and new build capacity costs—especially when developed with thoughtful spatial resolution (V.Best Practice 32)—can be used for avoided cost calculations that serve as the basis for incentives for distributed energy resource programs. These same data can also inform assessments and planning for virtual power plants.
- Renewable Portfolio Standards planning. Comparison of system costs across pathways that offer different penetration levels of renewable resources, with different emissions profiles, can inform renewable energy certificate price forecasts and emission abatement cost estimates.
- Transmission planning. Transmission expansion decisions made by the capacity expansion model can inform more detailed regional transmission expansion studies.
- Distribution system planning. IRP assumptions and results on the relative balance between utility-scale and distributed energy resources can inform distribution system analysis—in particular, distributed energy resource adoption and operation scenarios. IRP scenario assumptions and model results that capture interactions between distributed and bulk power system resources are critical inputs into distribution system planning analysis. Conversely, high levels of distributed energy resources at the distribution level impact the need for bulk power system resources, as well as bulk power system operation. A growing number of states require integrated distribution system planning (LBNL n.d.-b), a decision framework that addresses interactions across planning domains and enables formulation of long-term grid investment strategies to address policy objectives and priorities, consumers' needs, and evolution at the grid edge (U.S. DOE n.d.).

## Best Practice 48. Evaluate bill impacts

*Evaluate bill impacts by customer class as part of the IRP process.*

IRP modeling evaluates how resource decisions impact total system costs, not how decisions impact cost recovery and cost allocation. If a resource planning decision is likely to have a significant impact on system costs and customer bills, ignoring rate impacts during an IRP may lead to unexpected impacts on utility customers. Examples of such decisions are large buildouts of supply-side resources to meet data center load growth and retirement decisions for aging power plants.

First, data center load is expected to grow dramatically in many parts of the country. The attractiveness of these locations to prospective data centers is based in large part on current low power costs. But to meet projected data center load, utilities are proposing to build a substantial quantity of new resources and continue to operate aging resources. The new power system will not look or cost the same as the current system, and therefore electricity rates are not likely to be the same. Regulators need information on what portion of bulk power system costs the data centers are likely to pay, and what portion residential and other customer classes will pay to make well-informed decisions regarding approval of new supply-side resources. This is particularly important in the case where the utility considers data center load as a potential market to justify new generating resources, even though the load would be located outside the utility service territory, where the utility has no obligation to serve (GPC 2023 Response to STF-JFK Data Request 4-4).

Second, for aging fossil fuel plants, utilities can analyze different ratemaking options to determine retail rate impacts and impacts on retirement timelines. Once a utility has identified in an IRP proceeding an economic early retirement date, it can explore all ratemaking options under which to economically retire that unit. Such analyses can be included as part of the IRP process, or the analysis may be done partially or entirely outside of an IRP proceeding—for example, in a rate case.

Typically, utilities depreciate assets according to a depreciation schedule aligned with the useful life of the resource. Ideally, by the time the asset retires, its value has been fully depreciated and it is removed from rate base. But when an asset becomes uneconomic before its scheduled retirement date, the utility and the regulator have options for addressing the remaining plant balance. Generally, maintaining the existing depreciation schedule while retiring a plant early is not an option, given the misalignment it would perpetuate between when costs are incurred and when they are recovered through rates. Stated another way, it is not good rate design practice to spread cost recovery out over a period of time when the asset is no longer providing value to utility customers.[36]

Regulatory options include the following:

1. *Status quo depreciation and retirement.* The utility can continue to operate the unit for its planned lifetime, regardless of economics, to allow the utility to continue to collect a full rate of return on the asset. The utility will continue to spend capital to maintain the asset, which will be

[36] In some states, such practice is unlawful. For example, Oregon ORS 757.355 states, "...a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer." (Oregon n.d.).

added to rate base, and will continue to pass costs onto utility customers for the originally planned lifetime.

2. *Accelerated depreciation and retirement*. A utility can request to adopt an accelerated depreciation schedule to more closely align the depreciation schedule for the resource with a retirement date that is earlier than the planned lifetime. This can cause rate shock if the change in schedule is too drastic (e.g., going from 15 years remaining lifetime to 5 years). To mitigate the shock, the utility can adjust the pace of accelerated retirement.
3. *Disallowance.* The regulator can disallow recovery of some or all undepreciated costs of the asset before the retirement date, with shareholders picking up the cost. However, this is more common for specific capital investments that are deemed imprudent, rather than for remaining balances for plants determined to be prudent at the time of the original investment.
4. *Regulatory asset.* The utility can turn the remaining plant balance into a regulatory asset with a depreciation date somewhere between the original date and the current retirement date. The negotiated rate of return would be lower than what the utility was collecting originally.
5. *Securitization or other alternative finance mechanism.* The utility can use securitization (where allowed by law) or another alternative financing mechanism, such as a loan from the Energy Infrastructure Reinvestment program under the IRA, to retire the plant early. The rate of return the utility receives on the asset would be lower than it was receiving before, but cost recovery of the remaining balance is more secure. For example, after its 2019/2020 IRP, CenterPoint Energy Indiana South pursued securitization of its A.B. Brown coal units as part of its generation transition plan (CenterPoint Energy 2023).

## Best Practice 49. Consider energy justice comprehensively

*Factor energy justice into all parts of an IRP process and engage impacted communities.*

Energy justice considerations are best factored in throughout the IRP process, from the time planners choose a model, develop input assumptions, and run scenarios, to when they present results to stakeholders and regulators. While energy justice is not a new concept, it is an emerging field of inquiry—in part because much of the data needed to fully estimate the comparative impacts of portfolios on impacted communities are not readily available. An emerging best practice for utilities is to begin to collect data on impacts of concern (e.g., high energy burdens, health impacts from emissions, poor system reliability) for priority populations (e.g., disadvantaged communities, minorities, customers with low incomes, customers who are medically dependent on electric service) during IRP processes. As the utility collects more data, it can be used to inform more detailed integration of energy justice considerations in future IRP cycles. Some jurisdictions are beginning to require this level of detail. For example, Washington state law requires electric utilities to file a clean energy implementation plan every 4 years. By law, the plan must identify highly impacted communities and vulnerable populations, as well as quantify customer benefits and reduction of burdens (Washington State Legislature 2022).

A comprehensive discussion of how energy justice factors into various best practices discussed in this report is outside our scope. Resources on this topic include a recently published report by Lawrence Berkeley National Laboratory and Synapse on distributional equity impacts of utility programs for energy efficiency and other distributed energy resources, which could be useful for informing equitable decision-making in the context of resource planning (LBNL and Synapse 2024).

RMI highlights several best practices for addressing energy justice in IRPs, such as the following (RMI 2023):

- Plan for community transition associated with asset retirements, including job losses, increased unemployment, loss of tax revenue, and reduced property values.
- Estimate comparative rate impacts of portfolios.
- Define and map disadvantaged communities to assess impacts, using tools such as Climate and Economic Justice Screening tool (CEJST), developed by the U.S. Council on Environmental Quality (U.S. CEQ CEJST n.d.), and Environmental Justice Screen (EJScreen) developed by the EPA (U.S. EPA EJScreen 2014)
- Factor community acceptance into resource availability and feasibility of plans.

Additionally, resource planners can also consider the following actions:

- Provide translation services and IRP modeling results in multiple languages suited to a utility's customers (refer to Best Practice 1 on creating an inclusive stakeholder process).
- Factor in resilience and disproportionate impacts during extreme events (Synapse 2021).
- Explicitly define how programs for energy efficiency and other distributed energy resources deployment support energy justice objectives.
- Define energy justice metrics and quantify how well each portfolio scores with respect to these metrics (see Step 4, Develop DEA metrics, in the Distributional Equity Analysis Practical Guide for information on how to do this) (LBNL and Synapse 2024).
- Publish and map pollutant values for existing assets and potential portfolios.
- Develop environmental and health cost scenarios and analyze portfolio impacts.

Hawaiian Electric Company is among utilities that have started to incorporate energy justice practices into resource planning processes. The utility mapped locations for microgrid hosting based on criticality (emergency or critical loads, facilities or infrastructure), vulnerability (areas that are prone to natural hazards, are inaccessible, or have experienced high outage rates), and societal impact (locations with social implications). For the societal impact criterion, Hawaiian Electric mapped disadvantaged communities using EJScreen (Hawaiian Electric 2022).

Figure 8 provides additional resources (clickable) with information on advancing energy justice in an IRP process.

*Figure 8. Additional resources on advancing energy justice in an IRP process—Click to view*

| | | |
|---|---|---|
| The Spectrum of Community Engagement to Ownership (Facilitating Power 2020) | The Energy Equity Playbook. ILLUME (Illume Advising 2021) | Initiative for Energy Justice: Justice in 100 Metrics (Lanckton and DeVar 2021) |
| State Energy Justice Roundtable Series: Participation in Decision Making. National Association of Regulatory Utility Commissioners (NARUC 2023) | Advancing Equity in Utility Regulation, Future Electric Utility Regulation Report. Lawrence Berkeley National Laboratory (LBNL 2021 Advancing Equity) | Designing Equity Focused Stakeholder Engagement to Inform State Energy Office Programs and Policies. National Association of State Energy Officials (NASEO 2020) |
| Community Energy Planning: Best Practices and Lessons Learned in NREL s Work with Communities (National Renewable Energy Laboratory 2022) | Power Play: Actions for New England's Equitable Energy Transition (Synapse Energy Economics 2023) | Equity in Sustainability: An Equity Scan of Local Government Sustainability Programs (Urban Sustainability Directors Network 2014) |

## Best Practice 50. Consider the evolving natural gas distribution industry

*Track the technical, financial, and regulatory developments of natural gas distribution firms operating in the electric utility's service territory to improve coordination.*

Electricity IRPs and gas distribution system planning are closely linked in multiple ways. For example, in areas of the Northeast that have limited access to natural gas, winter gas demand for building heating is creating emerging reliability challenges for natural-gas-fired power plants. Looking to the future, growing electrification of customer technologies such as water heaters, space heating systems, and cooking appliances is expected to increasingly transfer energy demand from gas distribution systems to electricity systems. This may change the dynamics of natural gas availability in places such as the Northeast and have wider effects nationwide on electricity IRPs and gas distribution planning. Crucially, economic decommissioning of natural gas distribution system assets, due to reduced gas demand, would prompt unexpected switching to electrified end uses across residential and commercial customers.

A best practice for electric utilities would be to track the technical, financial, and regulatory developments of natural gas distribution firms operating entirely or partially in their service territories. The IRP section that describes the utility's planning environment could describe the status of these natural gas distribution firms and potentially inform a sensitivity analysis for load forecasting that includes larger blocks of customers shifting to electrified end uses due to natural gas service phase-out.

### Looking Ahead: Integrate electricity and natural gas industry planning

An emerging practice points towards integration of electricity and natural gas industry planning to ensure improved coordination for optimal societal outcomes, both economic and distributional. A potential decrease in customers on gas distribution systems would translate to fewer customers available to pay for their maintenance. This may increase the financial burden on remaining gas customers, which raises energy justice concerns if higher-income customers electrify first and the risk of higher gas rates falls on those who are already disadvantaged. For example, the state of Washington issued a rulemaking decision mandating Integrated System Planning across electricity and natural gas (WA UTC 2024).

# Conclusion

Resource planning is challenging. During times of transition and market uncertainty it becomes even harder. It also becomes more important. As we leave behind a decade of flat load growth and look forward to projections of record load growth and continued decarbonization and electrification, robust resource planning is necessary to identify economic and reliable resource plans to serve utility customers, balancing uncertainties and risks facing the U.S. power sector today.

This guide outlines a list of 50 best practices for resource planning. They cover stakeholder engagement, resource adequacy, model input development, scenario and sensitivity design, modeling, portfolio and result evaluation, and integration of the IRP process with other proceedings.

Some best practices are straightforward and simple to implement while others require a considerable shift and reform of the resource planning process. All of these best practices represent actions or approaches we have seen implemented, or at the very least studied, by one of more utilities. Implementation steps vary, based on each utility's current planning practice.

The objective of this guide is to provide concrete steps for progress. While an ideal IRP process incorporates all best practices, IRP reform takes time. Utilities can use the guide to develop a roadmap and plan for how to improve the robustness of their IRP processes. Stakeholders can use the guide to help prioritize their engagements in the IRP process and identify where utilities are falling short. And regulators can use the guide to evaluate the reasonableness and robustness of each element of the IRP process and decide where to direct utilities to shift their approach to meet a higher standard for planning.

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