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Methods to Incorporate Energy Efficiency in Electricity System Planning and Markets

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Methods to Incorporate Energy Efficiency in Electricity System Planning and Markets

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Acronyms and Abbreviations

AC	Air conditioning
AEG	Applied Energy Group
AEP	American Electric Power
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CCCT	Combined-cycle combustion turbine
CEE	Consortium for Energy Efficiency
DSM	Demand side management
EE	Energy efficiency
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EV	Electric vehicle
FCM	Forward capacity market
FERC	Federal Energy Regulatory Commission
GWh	Gigawatt-hour
HVAC	Heating, ventilation and air conditioning
I&M	Indiana Michigan Power Company, a subsidiary of American Electric Power
IRP	Integrated resource planning
ISO	Independent system operator
ISO-NE	Independent System Operator – New England
kW	Kilowatt
kWh	Kilowatt-hour
MISO	Midcontinent Independent System Operator
MPS	Market Potential Study
MW	Megawatt
MWh	Megawatt-hour
NEMS	National Energy Modeling System
NYISO	New York Independent System Operator
PJM	Pennsylvania, Jersey, and Maryland Power Pool
RPM	Regional Portfolio Model (for Northwest Power and Conservation Council case study)
RPM	Reliability Pricing Model (for PJM case study)
RTO	Regional transmission operator
SAE	Statistically adjusted engineering (model)
SEER	Seasonal Energy Efficiency Ratio
TRM	Technical reference manual
UEC	Unit energy consumption
U.S.C.	United States Code
WECC	Western Electricity Coordinating Council

Executive Summary

Electric utilities, independent system operators and regional transmission operators (ISO/RTOs) have acquired significant levels of energy efficiency over several decades. In 2017, utility customer funded programs alone resulted in more than 29,000 gigawatt-hours of incremental electric savings in the United States and 4,470 megawatts of incremental demand savings (the equivalent of 13 average sized combined cycle natural gas power plants),[1] avoided the emissions of more than 20 million metric tons of carbon dioxide,[2] and saved households, businesses, and other end users more than $3 billion (CEE 2019).

The predominant approach utilities use to consider energy efficiency in electricity system planning and ISO/RTOs use in wholesale electricity markets is to reduce load forecasts to account for estimated impacts of relevant policies and programs. But an increasing number of states and utilities are interested in improved analysis of energy efficiency in electricity system planning and wholesale electricity markets. This report describes how to consider energy efficiency as a potential resource for the future by allowing it to compete with all other electricity system resources.

Increasing levels of wind and solar, growth in peak demand, and electrification of transportation and other new loads have increased the need for a more flexible and responsive electricity system. Considering energy efficiency as a resource option can support these and other electricity system objectives, including grid reliability, reduced electricity costs, energy efficiency targets, and lower air pollutant emissions.

Three principles guide this approach: (1) parity in planning, (2) symmetry in resource acquisition, and (3) equality in cost-benefit analysis (Figure ES-1).

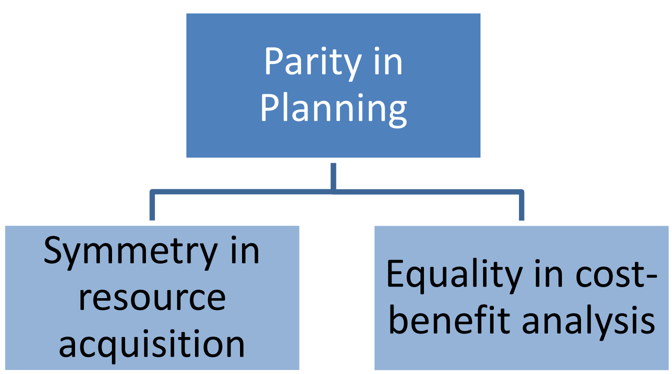

Figure ES - 1. Three Principles for Considering Efficiency as a Resource

[1] Average of operable Natural Gas Combined Cycle plant. EIA 860 (2019).

[2] Calculated using the EPA Greenhouse Gas Equivalencies Calculator. U.S. Environmental Protection Agency, accessed December 2020. https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator.

The overarching principle is ***parity in planning****.* Considering energy efficiency on a par with other resources in the planning process, or allowing it to compete in capacity auctions in wholesale electricity markets, enables selection and procurement of the optimal quantity. All resources compete based on their cost and performance characteristics, ensuring the development and operation of a reliable electricity system at the lowest reasonable cost. This principle acknowledges and embraces that resources have different planning and operating characteristics. In integrated resource planning, parity occurs when efficiency and other demand-side and generation resources are considered in a consistent manner with each other in system planning. In wholesale electricity markets, parity occurs when efficiency is eligible to compete with other resources that can meet requirements for the specified service.

Parity in planning encompasses two additional principles. ***Symmetry in resource acquisition*** applies to budgeting and spending for energy efficiency. When there is symmetry in resource acquisition utilities assume that they will acquire resources, including efficiency, up to a cost equal to its value to the utility system. Moreover, once the planning process provides the appropriate information to make resource procurement decisions, utilities consider efficiency on an equal footing with other types of generation, transmission, and distribution resources when making resource acquisition investments. In wholesale markets, symmetry in resource acquisition occurs in auctions that allow efficiency to compete and pay all resources clearing the market the same price.

Equality in cost-benefit analysis exists when efficiency is represented and quantified in a way that enables its direct comparison with other resources for acquisition decisions. In integrated resource planning, application of this principle primarily occurs in the resource potential assessment. This principle does not apply to centrally-organized wholesale markets because ISOs/RTOs do not conduct resource potential assessments.

Figure ES-2 shows how the three principles are applied in (1) load forecasting, (2) potential assessments, (3) capacity expansion modeling, and (4) risk and uncertainty analysis. It summarizes potential changes that utilities may make to their electricity resource planning process to consider efficiency as a resource (Figure ES-2). The report also discusses how the principles affect ISOs/RTO load forecasting and capacity markets.

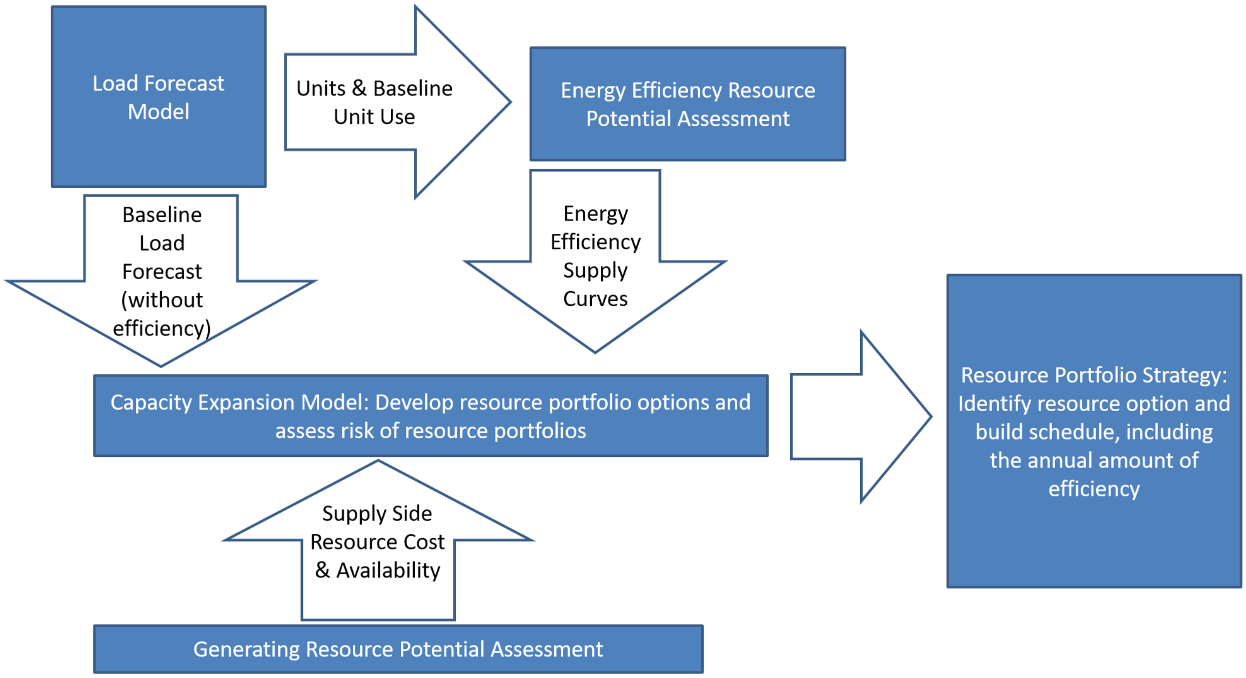

Figure ES - 2. Analytical Process for Considering Efficiency as a Resource

To illustrate how consistency with these principles may alter utilities' and ISO/RTOs' current approaches, the report provides case studies from diverse states that employ a range of methods and practices (Figure ES-3). We examine Indiana Michigan Power Company (I&M)[3] and PacifiCorp's integrated resource plans and the Northwest Power and Conservation Council's Seventh Power Plan, all of which use energy efficiency supply curves in their electricity planning. We also explore how ISO-New England and PJM consider energy efficiency in load forecasting and capacity auctions.

[3] I&M is a subsidiary of American Electric Power (AEP).

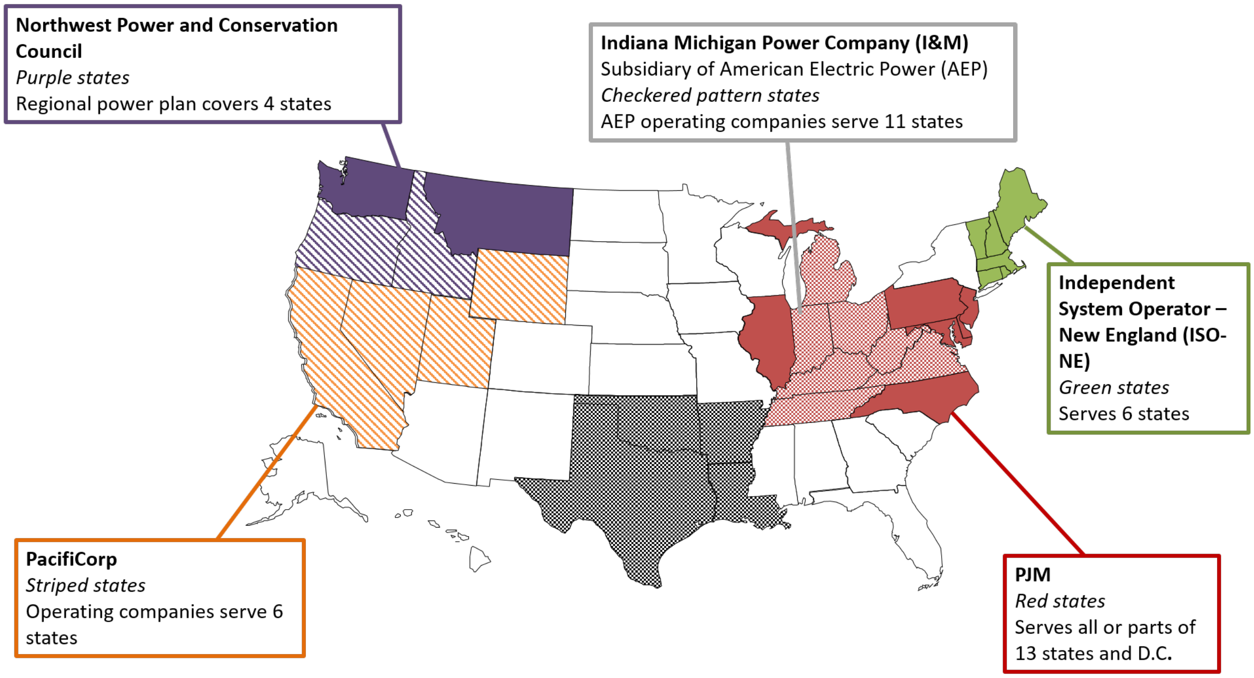

Figure ES - 3. Utility and ISO/RTO Case Studies in this Report

The case studies highlight strengths and opportunities for improvements when considering efficiency as a resource, some of which may be broadly applicable. Public utility commissions, electric utilities, ISOs/RTOs, and efficiency program administrators and implementers interested in advancing consideration of efficiency as a resource can:

- Use technical and economic information on energy efficiency that is comparable in scope and detail to what is used in analysis of generation resources.
  - Represent energy-efficient technologies and efficiency programs and requirements with an adequate level of detail and disaggregation.
  - Represent energy efficiency in an integrated way across all components of resource portfolio decision-making.
- Simulate direct competition between efficiency and generation to determine the quantity of efficiency to include in resource portfolios.
  - Determine the level of efficiency as a variable within planning and market processes, directly comparable to supply-side resources.

1. Introduction

Electricity resource planning—also referred to as *integrated resource planning* (IRP)—is the process of identifying longer-term investments to meet electricity reliability requirements and public policy goals at a reasonable cost. These processes typically provide a forum for regulators, electric utilities, and electricity industry stakeholders to evaluate the economic, environmental, and social benefits and costs of different investment options. The electricity resource planning process may play an important role in shaping utility business decisions because it often facilitates a discussion on future goals, challenges, and strategies (Kahrl et al. 2016).

Electricity resource planning emerged more than four decades ago. For example, when Congress enacted the Pacific Northwest Electric Power Planning and Conservation Act in 1980 (16 U.S.C. 12H), it defined "actual or planned load reduction resulting from a conservation measure" as a "resource" equivalent to the "actual or planned electric power capability of generating facilities." This was the first time that federal legislation defined these terms. Twelve years later, the Energy Policy Act of 1992 defined the term *IRP,* stating that electric utility planning and selection process for new energy resources should evaluate "the full range of alternatives, including new generating, capacity, power purchases, *energy conservation and efficiency* (emphasis added), cogeneration and district heating and cooling applications, and renewable energy resources." The Act further indicated that such evaluations "shall treat demand and supply resources on a consistent and integrated basis."

Resource planning occurs in more than 30 states, including most states with vertically integrated electric utilities and some states with centrally organized wholesale electricity markets ("restructured markets") (Figure 1). The vast majority of these states require regulated utilities to consider energy efficiency as a resource option in their electricity resource planning process (EPA 2015). The types of utilities (e.g., municipal, community choice aggregator, investor owned) that conduct electricity resource planning differs by state, but the principles offered in this paper may be employed by any utility conducting electricity resource planning.

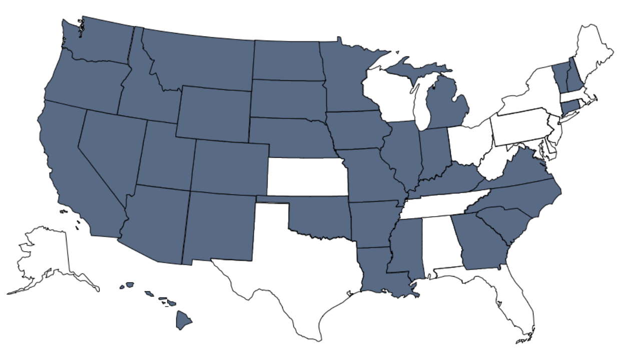

Figure 1. States with Electricity Resource Planning Requirements[4]

[4] Adapted from Synapse Energy Economics, Inc. IRP requirements vary by state. Florida requires utilities to file a 10-year site plan. In Tennessee, the Tennessee Valley Authority conducts an IRP, and in Alabama, Alabama Power conducts an IRP.

Among the many benefits of energy efficiency, it may:

- Reduce the cost and economic risk of meeting consumer needs for energy services
- Be acquired across a wide and nearly continuous range of costs
- Provide both energy and peak demand savings
- Be developed in quantities that more closely align with resource needs and reduce the risk of overbuilding the electricity system in the short-term
- Defer or reduce investments in distribution and transmission infrastructure and the need to acquire additional ancillary services (e.g., reserves)
- Be used to support many objectives, including reliability and resilience of the power grid, reduced electricity cost, energy efficiency targets, and lower air pollutant emissions
- Reduce the risk of a portfolio of resource options because it is not subject to fuel or market price risks, and does not emit air pollutants that may be subject to future regulatory changes

In the Southeast, Northwest, and portions of the Southwest—regions without centrally organized wholesale electricity markets (Figure 2)—utilities are responsible for system planning, operations and management, and serving load. Typically, resource planning and investment decisions are made by individual utilities. Electricity resource planning involves estimating the energy and capacity savings of a portfolio of programs, factoring those savings into forecasts of electricity load and peak demand, understanding how those savings will affect dispatch order (the pattern in which power plants are used to meet base loads and increments of daily and seasonal loads), and the need to develop new resources. Energy efficiency is incorporated to varying degrees based on state policies.

ISO/RTOs perform resource adequacy analysis. Their analysis does not attempt to identify or select any specific resources or resource mix, but instead seeks to ensure that there are sufficient resources to meet peak load while complying with applicable reliability standards. Energy efficiency's use in restructured markets varies from one jurisdiction to another. ISO/RTOs facilitate open access to the transmission system and operate markets to determine which resources will be dispatched (operated on the system) during each hour of the day.[5] Two regional grid operators (PJM and ISO New England) use capacity auctions to select efficiency as a resource. In addition, vertically integrated utilities in these two regions may acquire energy efficiency as part of a planning process (e.g., IRP) or bid energy efficiency into the markets. In the remaining ISO/RTO regions, demand forecasts of participating load-serving entities and state energy efficiency policies (e.g., energy efficiency resource standards, requirements to acquire all cost-effective energy efficiency, resource loading order) typically drive how regional grid operators include efficiency in planning for resource adequacy.[6]

[5] ISOs and RTOs operate the transmission system independently of, and foster competition for, electricity generation among wholesale market participants. Each of the regional grid operators operate bid-based energy and ancillary services markets to determine economic dispatch. Two-thirds of the nation's electricity load is in ISO or RTO regions. See https://www.ferc.gov/industries-data/market-assessments/electric-power-markets.

[6] See Barbose et al. 2014.

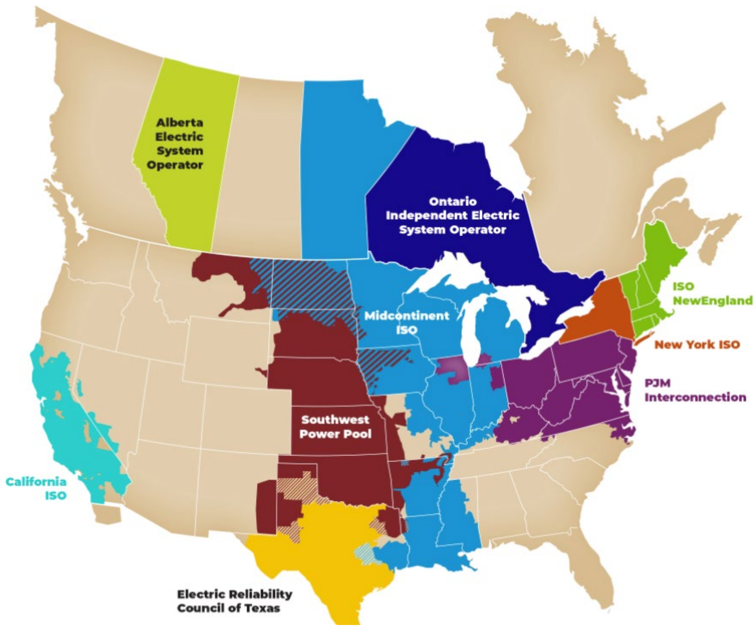

Figure 2. Centrally Organized Wholesale Electric Markets[7]

1.1 Approach

The authors developed three principles to describe how to consider energy efficiency as a potential resource for the future by allowing it to compete with all other electricity system resources: (1) parity in planning, (2) equality in cost-effectiveness analysis, and (3) symmetry in acquisition.

The essence of treating efficiency as a resource rests on the concept that it is an option available in the resource selection process. We discuss how these principles are applied to: (1) load forecasting, (2) potential assessments, (3) capacity expansion modeling, and (4) risk and uncertainty analysis. These four elements are based on the authors' experience developing and reviewing IRPs. The report also discusses how the principles affect ISO New England's and PJM's use of efficiency in their load forecasts and capacity markets.

To illustrate how consistency with these principles may alter utilities' and ISO/RTOs current approaches, the report provides case studies from diverse states that employ a range of approaches that allow efficiency to complete with all other electricity system resources (Figure ES-3). We examine Indiana Michigan Power Company (I&M)[8] and PacifiCorp's integrated resource plans and the Northwest Power and Conservation Council's Seventh Power Plan, all of which use energy efficiency supply curves in their electricity planning. We also explore how ISO-New England and PJM consider energy efficiency in load forecasting and capacity auctions.

[7] Figure from ISO/RTO Council. https://isorto.org

[8] I&M is a subsidiary of American Electric Power (AEP).

To create the case studies, we reviewed the utilities' integrated resource plan filings and analysis and energy efficiency potential studies. We spoke with utility staff responsible for integrated resource planning at I&M and PacifiCorp, and regulatory staff in Indiana. We reviewed load forecasts, auction rules, and results of the capacity auctions for the ISO-New England and PJM case studies. For the Northwest Power and Conservation Council case study, we reviewed the Seventh Power Plan and relied on our author's experience working with the Council for decades.

1.2 Organization of the report

The remainder of the report is organized as follows:

- Chapter 2 describes our conceptual framework and the three principles for using efficiency as a resource.
- Chapter 3 identifies the technical requirements implied by the principles and describes four components of electricity resource planning where treating energy efficiency as a resource in the process has the greatest impact.
- Chapter 4 discusses four case studies that illustrate how utilities, ISOs/RTOs, and a regional planning organization treat energy efficiency in electricity resource planning or markets.
- Chapter 5 provides observations and opportunities for states, utilities, ISOs/RTOs, and energy efficiency program administrators and implementers.

Technical appendices provide further detail on energy efficiency resource potential assessments and evaluating efficiency's risk.

2. Principles for Considering Efficiency as a Resource[9]

Traditionally, future electricity consumption and peak demand are represented in a load forecast, which establishes key system requirements: how much and when to produce or procure electricity over a given planning horizon. In traditional markets, utilities use resource planning to determine the timing and allocation of different generation sources to reliably meet this requirement, subject to cost-effectiveness and technical constraints. In restructured markets, ISOs and RTOs operate markets to determine which resources will be dispatched during each hour of the day. In both these approaches, the basic technique for incorporating efficiency into the planning process or market is to reduce the load forecast by an estimated quantity of efficiency. This results in "before" and "after" load forecasts, without and with reductions that will be achieved by efficiency. The "after" reflects lower projected levels of electricity use and serves to define the generation resource planning target. This can be characterized as treating efficiency as an exogenous *input* into electricity system planning or markets.

The essential idea of treating efficiency as a *resource* is that its optimal level and timing are instead determined endogenously; that is, efficiency becomes a *decision variable* directly comparable to amounts and timing of natural gas or renewable generation. We call this the principle of ***parity in planning*** (Figure 3).

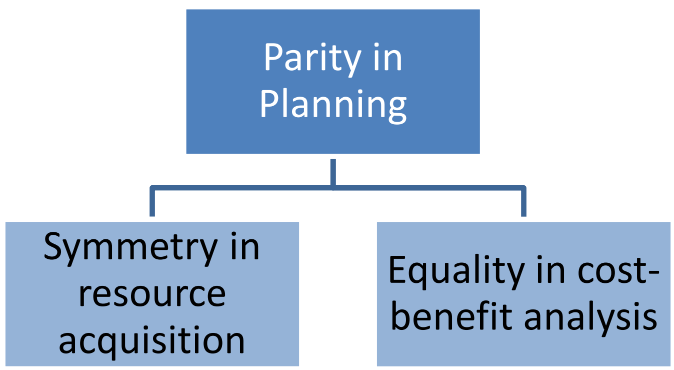

Figure 3. Three Principles of Treating Efficiency as a Resource

Parity in planning requires that a utility does not arbitrarily constrain investments in energy efficiency resources (e.g., limit budgets for energy efficiency acquisition based on the share of retail revenues dedicated to its acquisition).[10] Specifically, parity between supply curves (those for energy efficiency and those prepared for generating resources) requires that a utility not arbitrarily limit forecasts of achievable energy efficiency potential by its customers' willingness to pay for efficiency measures.[11] Supply curves for generating resources represent the expected total cost of their construction and operation, i.e., how much a utility forecasts it is willing to pay to develop or acquire those resources.

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[9] This section is based on Eckman (2013).

[10] Some states now have policies that *implicitly* seek to acquire "all cost-effective savings" while *explicitly* limiting utility or system benefit fund administrators' financial ability to do so.

[11] The term "willingness-to-pay" frequently applies to the share of an energy efficiency measure's cost offered to consumers by a utility or other energy efficiency program administrator in order to incent them to install or adopt the measure.

To maintain parity between efficiency resources and generating resources, utilities may base the amount of energy efficiency resources they estimate can be acquired by offering consumers full-incremental measure and program cost reimbursement of all measures in the efficiency supply curve.[12] This assumption parallels how utilities forecast the number of new natural gas-fired combined-cycle combustion, wind turbines, or solar installations that will be available (i.e., the utility assumes they will have to pay to acquire the resources). This principle also means that the constraints developed for energy efficiency potential studies are not arbitrary, but rather based on historic, current, and forecasted technology advancement and customer participation. Parity in planning occurs in restructured markets when ISOs or RTOs allow energy efficiency to participate in the market as a resource.

Parity in planning may require two major changes in electricity system planning relative to historical practice. The first change is the adoption of and adherence to the principle of ***symmetry in resource acquisition*** which applies to efficiency cost assumptions and acquisition of efficiency.

Utilities are prepared to fund the acquisition of new generating resources, or transmission or distribution facilities that they deem necessary to maintain a reliable power system. The principle of symmetry in resource acquisition simply means utilities assume symmetrical willingness to pay for all resources, including energy efficiency. When utilities implement this principle, they acquire efficiency if the full incremental cost of the measure is less costly than the next least expensive resource.[13] Once the planning process provides the appropriate information for making resource procurement decisions, utilities and regulators consider efficiency "on an equal footing" with generation, transmission, and distribution resources when making resource acquisition investments. In restructured markets, symmetry in resource acquisition occurs in the auction process where all resources are paid the same clearing price.

The second change that utilities may need to make in their planning process is to ensure that efficiency is represented and quantified in a way that enables its direct comparison with other resources for acquisition decisions (e.g., capacity expansion modeling). We call this ***equality in cost-benefit analysis*.** Utilities generally test the economics of self-generation resource options (or long-term power purchase agreements) against competing resources using some form of a life-cycle cost analysis. This can range

[12] Energy efficiency measures provide both energy and capacity benefits. Robust evaluation of their cost-effectiveness will consider the savings load shape to value their contribution to the power system properly. In addition, evaluations are necessary to quantify the savings from efficiency measures, so investments in evaluation, measurement, and verification of savings should be included in the cost of acquiring this resource. There are generally accepted guidelines and protocols for quantifying savings. See CEE (2007) and Goldman, Messenger and Schiller (2010).

[13] Using the full incremental cost of the energy efficiency measure is logical during electricity system planning because it is a comparable to supply-side resource costs. Utilities can use a different price when determining their energy efficiency acquisition program cost (e.g., more or less than the full incremental cost). For example, if a measure is determined to be cost-effective, paying up to the cost of the next similarly available and reliable resource (including more than the full incremental cost of an efficiency measure) still results in net economic benefit. Other costs or benefits that are not included in capacity expansion modeling can be included in the energy efficiency supply curves. See the levelized total resource cost discussion in the Northwest Power and Conservation Council case study for an example.

from a simple side-by-side comparison of present value of capital, operation and maintenance, and fuel cost to testing an array of resources in sophisticated capacity expansion models. Regardless of the approach taken, equality in cost-benefit analysis means that utilities use the identical screening criteria and process for energy efficiency as they use for generating resources. They do not create separate definitions or processes for determining the cost-effectiveness of energy efficiency. The cost-effectiveness of all resources is determined by comparing their cost and benefits to those of the next least-cost, similarly reliable and available resource.[14] In practical terms, following this principle means that energy efficiency resources are compared directly to generating resources based on their economic and other relevant resource characteristics (e.g., construction lead times and schedule flexibility, load shape, dispatchability, reliability, forced-outage rates, carbon emissions, and fuel and market price risks).

Observing equality in a cost-benefit analysis also requires that efficiency resources, including efficiency from existing programs, compete against new resources in the same manner that existing generation assets are treated. This means the utilities do not include embedded future savings from the continuation of existing programs or estimate consumers' response to future prices in the load forecasts used in their capacity expansion model.[15] This analytical approach tests the cost-effectiveness of all potential improvements in energy efficiency, even for measures included in existing programs. This process parallels the process for determining whether an existing generating resource should be retired or mothballed because its incremental dispatch production costs are above those of new resources.

Finally, equality in resource cost-benefit analysis requires that the analysis of efficiency benefits captures—at a minimum—all power system avoided costs.[16] For utility system valuation purposes this requires that its economic value reflect its impacts across all asset types (generation, transmission, and distribution), including the value of risk reduction and improved reliability and resilience. Other costs

[14] The Northwest Electric Power Planning and Conservation Act's definition of resource cost-effectiveness predated the publication of the California Standard Practice Manual by three years. The Power Act's definition states that: "cost-effective," when applied to any measure or resource referred to in this chapter, means that such measure or resource must be forecast to be reliable and available within the time it is needed, and to meet or reduce the electric power demand, as determined by the Council or the Administrator, as appropriate, of the consumers of the customers [sic] at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource, or any combination thereof" (Northwest Power Act, supra note 1, at §3(4) (A) (ii), 94 Stat. 2698).

[15] However, the baseline forecast does reflect savings from measures installed prior to the forecast period. As is the case with the capital cost of existing generating resources, utilities view investments in these resources as "sunk costs" and not avoidable.

[16] The economic benefits of energy efficiency to the utility system are the foundational values on which other benefits (and costs) can be built. Establishing the economic value to the grid of energy efficiency provides the information needed to design programs, market rules, and rates that align the economic interest of utility customers with building owners and occupants. By nature, energy efficiency directly affects customers and provides societal benefits external to the utility system. Jurisdictions can use utility system benefits and costs as the foundation of their economic analysis but align their primary cost-effectiveness metric with all applicable policy objectives, which may include customer and societal (non-utility system) impacts. For a more extensive discussion of the cost-effectiveness tests used to screen energy efficiency see Woolf et al. 2017.

that may be avoided or deferred include reduced ancillary service (e.g., reserve) requirements and transmission and distribution system reinforcement or expansion.

3. Technical Considerations for Using Efficiency as a Resource in Electricity System Planning and Capacity Markets

This chapter discusses how the three principles identified in Chapter 2 are applied in (1) load forecasting, (2) potential assessments, (3) capacity expansion modeling, and (4) risk and uncertainty analysis. It summarizes potential changes that utilities may make to their electricity resource planning process to consider efficiency as a resource (Figure 4). We also discuss how the principles affect ISOs/RTO load forecasting and capacity markets.

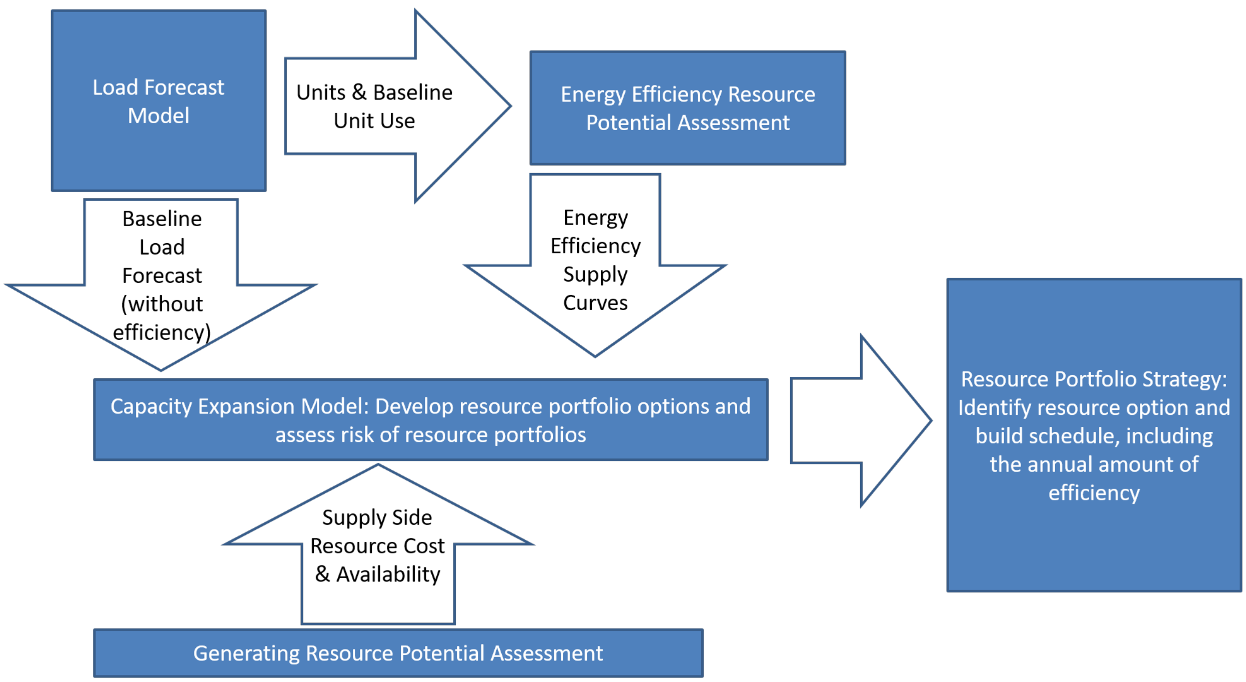

Figure 4. Analytical Process: Efficiency as a Resource in Utility Planning

3.1 Load forecasting

Electricity load forecasts predict total electricity consumption (measured in kilowatt-hours, kWh) and peak load (measured in kilowatts, kW). Electricity and peak load forecasts provide the foundation for resource planning, daily operation, and risk management in the electric power sector. Load forecasts are used by electricity resource planners and ISO/RTOs primarily as a basis for understanding future electricity needs and developing plans to ensure there are adequate resources to meet that demand, without incurring excess costs.

The goal of long-term (e.g., 10 to 30 year) electricity resource planning is to identify resource portfolios and management strategies that provide safe, reliable services at reasonable cost while managing the risks associated with the future uncertainties involved. Understanding a utility's current trajectory or forecast of electricity and peak load demand is the first step in electricity resource planning and also the first opportunity where treating the efficiency as a resource requires special attention.

Efficiency as a Resource: Summary of Potential Changes to Load Forecasting

Utilities or ISO/RTOs may need to alter their current practices of accounting for efficiency in their load forecast to achieve the following outcomes:

- The load forecast is a process that establishes a range of future load states.
- Load forecasting models have sufficient detail on end-use technologies to explicitly capture and isolate the potential impacts of utility efficiency programs, codes and standards, and other factors that influence energy use.
- Efficiency improvements resulting from stock turnover and known appliance standards and building energy codes are included in the load forecast. All remaining efficiency potential (e.g., efficiency due to consumer response to increased electricity cost, naturally occurring efficiency, and utility efficiency programs) is excluded from the load forecast.
- The outputs of load forecasting models serve as explicit inputs to energy efficiency resource potential assessments and the capacity expansion modeling process.

Meeting these requirements will generally entail the use of end-use econometric load forecasting models, rather than purely statistical/econometric models.

Three attributes may be used to guide utilities when creating a load forecast.

- *Uncertainty in the future and resource risk profiles:* Long-term load forecasts reflect the uncertainty about future load growth and the nature of loads (e.g., shape, variability) in order to evaluate the *relative* risk of energy efficiency vis-à-vis other resource options. The role of the load forecast in the resource planning processes is to establish a range of future load states, rather than attempting to accurately predict a single future. Utility load forecasting processes that treat energy efficiency as a resource acknowledge both the impossibility of precisely forecasting the future and that energy efficiency resources present a different risk profile than generating resources.
- *Granularity:* Load forecasting models must have sufficient detail on end-use technologies to explicitly capture and isolate potential efficiency impacts on both the magnitude and shape of future loads, including technical, policy, and regulatory changes affecting energy demand (e.g., appliance standards and building energy codes, increased penetration of electric vehicles [EVs], central air conditioning [AC], data centers, distributed generation) and changes in weather patterns.[17]

[17] If future weather conditions such as temperature extremes are forecast to differ from historical patterns, peak demands may be over- or under-estimated. In areas reliant on hydroelectricity, the timing and/or magnitudes of water flows may then deviate from historical norms, thereby altering hydro power output.

- *Consistency:* Load forecasts serve as the baseline against which remaining potential for energy efficiency is estimated. To treat energy efficiency as a resource, load forecasting models are calibrated to use internally consistent assumptions for parameters such as baseline energy use and the number and type of new and existing buildings and appliances.

Finally, these enhancements together enable *endogeneity* of efficiency-deployment decisions in the planning process: The *outputs* of load forecasting models serve as explicit *inputs* to efficiency resource potential assessments and the capacity expansion modeling process.

Parity in planning can also be applied to load forecasts in restructured markets. ISOs/RTOs that, through market mechanisms, compensate energy efficiency to maintain reliability achieve parity in planning. We will discuss this approach in our case study of ISO-New England and PJM in Chapter 4.

Incorporating Energy Efficiency in Load Forecast – Models Matter

End-use/Econometric or Statistically Adjust Engineering (SAE) load forecasting models are best suited to treating energy efficiency as a resource because these types of models have the end use detail needed to explicitly represent the efficiency levels or unit energy consumption, load shapes, and “unit counts” of major appliances and equipment.

The primary advantage of end-use econometric models with respect to treating energy efficiency as a resource is that they permit more internally consistent assessment of remaining energy efficiency potential, since they allow a direct comparison between the level of efficiency assumed in a load forecast and the level of efficiency that could cost-effectively be substituted for generation to meet future demand. For example, the magnitude of potential savings from some energy efficiency measures (e.g., appliances, heating and cooling equipment, new construction) is a function of economic growth. As a result, the supply curves for these energy efficiency measures need to be scaled with the load forecast path (e.g., low, medium, high) input into capacity expansion models. If the data and forecasts of input variables are available, end-use econometric forecast models also can provide more insight into the primary drivers of electricity consumption.

SAE load forecasting models are a type of end-use econometric models that aggregate multiple end uses for modeling purposes. For example, an SAE approach in the residential sector might be to combine detailed appliance data into three aggregate end-use variables for cooling, heating, and non-weather sensitive end uses, including lighting, cooking, and refrigeration. These accounting variables are then inserted into econometric equations. When data exist to develop SAE models, this model form can be attractive, because, like other end-use econometric models, such models offer the potential to explicitly represent the baseline efficiency embedded in load forecasts, including the future effects of energy efficiency codes, standards, and/or programs.

The primary disadvantage of purely econometric models when energy efficiency is used as a resource is they do not enable explicit comparison of efficiency levels embedded in a load forecast to estimates of remaining efficiency potential since the individual end uses of electricity are not modeled. They are also limited in their ability to accurately reflect the impact of policy or regulatory changes that may affect the future but did not occur in the past (e.g., new building energy codes or revised appliance standards, emerging technology, or market trends).

3.2 Resource potential assessment

Resource potential assessments identify the cost, availability, and performance characteristics of energy efficiency resources. The objective of the assessment is to provide accurate and reliable information regarding the amount, end-use or savings load profile, availability, and cost of acquiring or developing the energy efficiency resources.[18]

Efficiency as a Resource: Summary of Possible Changes to Potential Assessments

Utilities may need to alter their current energy efficiency resource potential approaches to achieve the following outcomes:

- Input assumptions (e.g., unit energy consumption, load shapes, the number and type of new and existing buildings, appliances, and equipment) used in potential assessments are explicitly calibrated with load forecasts.
- Efficiency from stock turnover and known appliance standards and building energy codes are the *only* savings included in the load forecast. All remaining efficiency potential is included in the potential assessment, including naturally occurring efficiency, efficiency due to consumer response to increased electricity cost, and utility efficiency programs.
- Efficiency potential estimates are *only* constrained by non-financial market barriers (e.g., product availability, delivery infrastructure limits, split-incentives for renters versus owners). They are *not* constrained by assumed levels of required consumer cost-sharing.
- Estimates of efficiency potential reflect historical experience and assume that utilities can and will acquire energy efficiency resources up to a cost equal to their value to the utility system.
- The products of resource potential assessments are energy efficiency supply curves that serve as inputs to capacity expansion models.
- Efficiency supply curves represent the quantity of efficiency that can be reliably obtained at a range of costs, in the form of measures or groups of measures with similar characteristics (e.g., load shapes, levelized cost, and deployment constraints).
- The efficiency supply curves are used in economic comparison of potential new investments in energy efficiency, other demand-side resources, and generation investments, including any difference in their dispatchability.

Resource potential assessments that build potential from the bottom up are a bridge between load forecasting and capacity expansion modeling. They use historical, current, and forecast information to estimate how much energy efficiency is available, both in the short run and over the entire planning horizon by resource type. This information is developed and assembled in a consistent way to provide the inputs to capacity expansion models necessary for *endogenizing* efficiency in those models' optimizations. Accurate representation of the unique characteristics of energy efficiency resources in

[18] See Appendix A for more detail and the U.S. Department of Energy's Energy Efficiency Potential Studies Catalog: https://www.energy.gov/eere/slsc/energy-efficiency-potential-studies-catalog.

capacity expansion models is necessary so they are treated symmetrically in the model's optimization processes.

Estimates of efficiency potential both reflect historical experience of best practice program design and delivery. For example, a review of regional energy efficiency accomplishments compared to achievable potential estimates in the Northwest supports the assumption that over a 20 year period 85 percent of economic potential can be achieved for retrofit measures and that 65 percent of economic potential can be achieved for lost-opportunity measures (NWPCC 2007).

Potential assessments consider efficiency measures that span a large cost range.[19] Functionally, this means that the potential estimates are only constrained by non-financial market barriers (e.g., product availability, delivery infrastructure limits, split-incentives for renters versus owners) and are not constrained by financial incentive and customer participation assumptions. Instead, the assessment assumes that all incremental costs are included in the efficiency cost. This creates symmetry in resource acquisition between demand and supply-side resources because the model assumes the utility will pay for all of both resources. Additionally, consumer economic barriers to participation become much less of a constraint on the level of available energy efficiency because they are not assumed to pay any incremental cost for resource planning. As discussed above, this does not require the utility to pay all incremental costs when it develops its energy efficiency implementation plans.

Potential assessments also provide capacity expansion models with separate and unique maximum development rate input assumptions for retrofit and lost-opportunity resource types (discussed more in Section 3.3 below). Lost-opportunity measures are those that can be acquired only during specific windows of opportunity, such as when a new home is being constructed or a new appliance purchased; retrofit resources are those that can be acquired at any time through measures that begin providing energy savings immediately. Different restrictions are placed on the ability of the capacity expansion model to acquire lost-opportunity and retrofit efficiency resources based on their availability characteristics.

3.2.1 Efficiency supply curves

One of the products of resource potential assessments are efficiency *supply curves* that quantify the levels of efficiency that can be obtained at a range of costs. These curves enable the economic comparison of efficiency and new generation investments. This approach treats energy efficiency as a resource that can be acquired to meet future demand for both energy and capacity. Each supply curve represents the aggregate savings of a bundle of individual energy efficiency measures with unique characteristics. Multiple supply curves are necessary to account for end-use load shape, development limits, and cost of the resource acquisition.

[19] See Figure 15 for an example of range of costs.

Variations in end-use load or savings shape[20] are used to determine the capacity value of the resource. Most energy efficiency measures produce energy savings that vary over the course of a year. The capacity value of the supply curves will vary by locations because of the physical and operational characteristics of the individual utility system (e.g., summer or winter peaking, load factor, reserve margin) and the time periods during which savings from the supply curves occur.

The levelized cost of energy (i.e., cost of resource acquisition) of each block in the efficiency supply curves reflects the *total resource net levelized cost* of acquiring and maintaining savings for the entire planning period. Total resource net levelized costs of energy efficiency are used because, without them, capacity expansion models typically do not capture all of efficiency's costs and benefits symmetrically with generating resources. For example, the total resource net levelized cost of the efficiency in supply curves should include any adjustments necessary to reflect the cost of program administration, measure replacement, credit for transmission and distribution investment deferrals, and other non-energy system benefits that are not captured directly in the economic analysis conducted in the capacity expansion model, but are included in a jurisdiction's cost-effectiveness criteria.[21]

In addition, the total resource net levelized cost of efficiency measures with expected useful lives less than the planning period are adjusted to reflect the cost of ensuring that savings persist throughout the full planning period. One option to achieve this is to add the present value cost of measure replacements that occur within the planning period to the supply curves. This is comparable to the approach used to generate resources where operation and maintenance, as well as periodic capital replacements of power plant components, are included in their levelized cost to maintain their performance over an assumed lifetime. Other approaches can be used to address efficiency resources with measure lives less than the duration of the planning period. Regardless of the approach used, it should be consistent with that used for generating resources.

For more information on resource potential assessments, see Appendix A.

[20] For more information on end-use load shapes and savings shapes, see Frick et al. 2019; Frick and Schwartz 2019; and Mims et al. 2017.

[21] For example, a jurisdiction may require estimates of the societal cost of greenhouse gas emissions or estimated risk reduction benefits of energy efficiency be included in its cost-effectiveness test.

3.3 Capacity expansion modeling

Capacity expansion models are computer simulation models used by utilities and electricity planners to determine the types, levels, and timing of additional resources in a power system necessary to reliably meet projected future increases in energy and peak demand needs. Technically, they are economic optimization models in which the objective is to find resource portfolios that minimize the net present value of revenue requirements (capital and operating costs) needed for supplying energy and peak demands while meeting reliability standards. In some cases, minimizing risk or meeting environmental goals, or both, might also be included as objectives or constraints on the model's optimization. A model solution (the capacity expansion model output) is a minimum-cost resource portfolio and a timeline for implementing it.

Efficiency as a Resource: Summary of Possible Changes to Capacity Expansion Modeling

Utilities may need to alter their current capacity expansion modeling to achieve the following outcomes:

- Efficiency supply curves serve as an input to capacity expansion models to use their optimization processes to find an accurate cost-effectiveness level for energy efficiency acquisitions.
- Efficiency supply curves are included as resource options that can be selected by the capacity expansion model for development, and not as exogenous reductions to load forecast inputs for long-term capacity expansion models or shorter-term estimates of capacity needs by regional grid operators.
- Economic potential (the amount of energy efficiency determined to be cost-effective) is determined by the optimizations in capacity expansion modeling, not in the potential assessment.
- Capacity expansion modeling acquisition logic is modified to account for energy efficiency's specific development characteristics (e.g., efficiency can be developed in small increments that accumulate to significant capacity over multiple years; some of the potential is correlated to the pace of load growth).

Conventional practice in electricity system planning incorporates efficiency assumptions into a load forecast. The growth rate of energy or peak demand, or both, in load forecasts is reduced by the identified economic quantity of efficiency. Then, based on these lower load forecasts, the capacity expansion model optimizes the type, amount, and schedule of new conventional resources (generation and/or transmission and distribution) to maintain system reliability at the lowest net present value system cost. This modeling approach inherently assumes that energy efficiency resources are "price takers" and not "price makers." When using this approach, the development of energy efficiency will not affect the type, amount, and schedule of conventional resource development to an extent that alters the avoided cost of the utility system being modeled.

By contrast, the defining step in using efficiency as a resource is allowing it to compete directly with other resource options in the determination of optimal portfolios in the capacity expansion model. This approach tests whether the development of energy efficiency will alter the avoided cost of the utility system being modeled by accounting for interactions between energy efficiency and the utility system in which it would be installed.

Allowing efficiency to compete with other resources in capacity expansion modeling may necessitate two changes to the standard modeling methodology.[22] First, efficiency options must be represented in capacity expansion models with the same level of granularity (e.g., hourly, on-peak versus off-peak hours), detail (e.g., end use versus customer level), and availability (e.g., development lead times and maximum annual and cumulative capacity) as supply-side (e.g., utility scale generating and utility scale storage) resources. Second, the decision logic and certain optimization details in the capacity expansion model must be customized to allow simultaneous consideration of the amount and timing of efficiency deployment and generation resources, using the same models and modeling processes. These two changes, if needed, allow the capacity expansion models to test resource portfolios that jointly estimate the impact of energy efficiency, generation, and transmission capacity investments over a wide range of assumptions about future electricity demand, fuel prices, technology cost and performance, and policy and regulation. The models can then address such questions as:

- What level of energy efficiency deployment results in the lowest utility system cost?
- How will future prices and volatility of natural gas affect the optimal amount of efficiency for meeting future capacity requirements?
- How will alternative levels of renewable resources influence the cost-effectiveness of efficiency in meeting system reliability requirements with variable generation?
- What will be the impacts of environmental policies on the mix and cost of generation and capacity?

In the remainder of this section we provide details on potential changes utilities may need to make to their capacity expansion modeling process.

3.3.1 Maximum efficiency resource development rate and acquisition logic

As mentioned above, potential assessments provide capacity expansion models with separate and unique maximum development rate input assumptions for retrofit and lost-opportunity resource types. Lost-opportunity supply curves are restricted by economic activity (e.g., new building construction and appliance and equipment replacement rates). This means that the model logic scales efficiency potential to the specific load growth path being tested in the capacity expansion model. For example, if the capacity expansion model uses pre-generated load growth paths (e.g., low, medium, high), then lost-opportunity potential associated with each load growth path might be accomplished using model input assumptions. However, if the capacity expansion model generates load growth paths from

[22] The suggested changes may need to be made by the utility's software vendor, or the utility may need to modify its own models to incorporate efficiency as a resource. Changes to capacity expansion models will not be uniform.

stochastic inputs, then the model's logic must be able to ensure a consistent relationship between lost-opportunity potential and the pace of load growth.[23]

Specialized resource expansion logic is also needed for each decision interval—the time periods used in capacity expansion models during which resource "build" determinations are made—for the model to select lost-opportunity supply curves with expected useful lives less than the planning period. For example, over the course of a 20-year planning period, an appliance with an expected life of eight years will be, on average, replaced twice. The capacity expansion model logic must be able to test the cost-effectiveness of acquiring savings from these appliances each time they come up for replacement. This allows the model to select lost-opportunity resources that were not previously acquired if a subsequent opportunity arises later in the planning period when avoided resource costs are potentially higher or resource need may be greater, or both.

Efficiency potential that is included as a retrofit supply curve, while available at any time in the planning process, cannot all be developed instantaneously. To reflect the feasible scale of efficiency programs, the potential within each decision interval must be subject to limits on their deployment rate. For retrofit supply curves, the models must have acquisition logic that enables setting maximum annual limits on the deployment of measures. This is particularly important when the retrofit supply curves contain significant achievable potential available at a levelized cost below short-run market prices or the dispatch cost of some existing resources. Without such limits, the capacity expansion model will select all achievable retrofit potential with levelized cost below these thresholds during the first decision interval of the planning period if the efficiency resources cost less than either market purchases or dispatching existing resources.

3.3.2 Program delivery flexibility

Capacity expansion model logic may need to be modified to consider program flexibility by permitting efficiency resources to be "mothballed" and then restarted. This logic is designed to address the possibility that efficiency programs are sometimes ramped up or down depending on their cost-effectiveness, but the infrastructure to deliver them may not completely disappear. It also creates consistency between efficiency and generation resources in the model.

3.3.3 Analyzing acquisition in advance of need for energy and capacity reserves

System planners may select resources to meet planning reserves based primarily on capital cost with less focus on their dispatch cost because these resources are only intended for dispatch under extenuating circumstances (e.g., loss of a generator or an extreme weather event) and are not expected to recover their capital cost through market sales. As a result, resources held for planning reserves are not typically subjected to the economic valuation process (i.e., compared to market prices).

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[23] For example, this may be done by creating scalars (quantities that are described by magnitude or numerical value) that adjust the quantity of lost-opportunity resource potential for a stochastically generated load forecast relative to one or more pre-generated load forecasts.

New resource strategies may be needed to test energy efficiency's value as a source of planning reserves in capacity expansion modeling. Evaluating a resource strategy that continuously acquires differing amounts of efficiency with a levelized cost above forecast market prices will sustain or increase the reserve margin by acquiring efficiency. Including this type of resource strategy allows the capacity expansion model to determine whether using efficiency to meet planning reserve needs will result in a lower net present value total cost of serving load. For example, the continuous deployment of above forecast market price energy efficiency recovers some of its value at all market price levels, which may produce a lower net present value for the system. In contrast, a generating resource being held for reserves must be occasionally dispatched to potentially recover any of its capital cost.

3.4 Risk and uncertainty analysis

All resource development poses some degree of economic risk, yet not all resources pose the same type or level of economic risk. Incorporating the cost of risk or the value of risk mitigation into capacity expansion modeling can alter the cost of alternative resource actions for both supply-side and demand-side options. To evaluate the relative risk presented by energy efficiency as compared to generating resources requires consideration of uncertainty in the capacity expansion modeling process.

Cost- and time-related risks stem from both the *intrinsic characteristics* of a resource and from the *inherent uncertainty* regarding future conditions (e.g., the pace of load growth, market and fuel prices, technology change) in which the resource will operate. The intrinsic characteristics of resources interact directly with the inherent uncertainty of future conditions to create economic risks.

Energy Efficiency (EE) as a Resource: Summary of Potential Changes in Risk and Uncertainty Analysis

Utilities may need to alter their current risk and uncertainty analysis to achieve the following outcomes:

- Consideration of efficiency's characteristics in electricity system planning risk and uncertainty analysis
- Comparison of efficiency and supply-side resource risk through stochastic analysis across a range of future conditions

Some generating resources, such as central station electricity generating units with large, minimum economic project sizes and extended development lead times, present large economic risks if future conditions (e.g., the pace of load growth, technology development) do not unfold as expected.

Energy efficiency has a different risk profile than generating resources:

- Energy efficiency resources have intrinsic characteristics (i.e., short lead times, small project sizes, limited fuel price sensitivity) that make them less risky over a wider range of future conditions and present lower economic risk; however, efficiency resources are also not dispatchable, and that may make them either more or less risky depending on the range of future conditions.

- Efficiency serves as a hedge against future fuel and market price risks because it reduces the need for new supply-side resource development. Efficiency can extend the ability of existing resources to meet demand, which creates less need to develop new resources, including the potential cost associated with transmission and distribution infrastructure.
- Efficiency may reduce economic risk associated with new supply resource development, such as capital cost escalation, regulatory risk, and future fuel price exposure by avoiding or significantly reducing the need to build or procure new resources.

There are a number of methods for analyzing risk and uncertainty, including several that are particularly suited to computer modeling. Two of these are scenario/sensitivity analyses and probabilistic analyses. Scenario analysis and sensitivity studies are typically used to establish the magnitude or threshold of the acceptable level of economic risk, after which a different decision would be justified. Both scenario analysis and sensitivity studies can be used for a wide range of complexity. Scenario analysis and sensitivity studies typically use deterministic models, where the output of the model is fully determined by the parameter values and the assumed initial conditions. In deterministic models, there is only one right answer to the question of the type, amount, and timing of resource development. However, by changing the input assumed for one parameter, the sensitivity of the "right answer" to that parameter can be tested.

A more sophisticated and complex practice employs *stochastic* or *probability analysis* to quantify the economic risk of efficiency relative to other resource options. The primary benefit of this practice is that it quantifies economic risk using probability distributions rather than using single point (deterministic) estimates for the value of each of the major risk factors (e.g., pace and volatility of load growth, air pollutant emissions costs, construction cost, and future fuel and market prices). In this approach, risk is viewed as randomness, which is measurable, and as a result it can be described by a probability distribution.

Actual future conditions often vary significantly from those that were anticipated, and the future conditions that pose the greatest risk are generally those that depart most from the expected value or medium case often used to select resource strategies. Robust risk analysis will consider how efficiency programs increase or decrease risk *relative* to commodities that influence the cost of energy, including natural gas, coal, air pollutants, market prices for energy, and supply-side alternatives. These future conditions typically are those with high load requirements coupled with high market prices for electricity or those with low load requirements coupled with low market prices for electricity.

In futures with anticipated high market prices—due perhaps to increasing air pollutant emissions control regulations or high natural gas prices—resources that have significant fuel cost are dispatched very infrequently, and therefore have less opportunity to recover their fixed costs. In addition, in these future conditions the risk mitigation value of energy efficiency is its availability when price spikes occur.

At the other end of the spectrum, in future conditions with low market prices—due perhaps to increasing penetration of renewable resources, technology innovation, or low natural gas prices—resources that have significant fuel cost also dispatch very infrequently and, therefore have less opportunity to recover their fixed cost. As a result, resources that perform best in high risk futures are those with low or no dispatch cost. This means that dispatchable resources, such as simple or combined cycle combustion turbines, are not attractive risk-mitigation resources, regardless of their nameplate capacity factor.

Appendix B provides further details on these methods and how they can be used to analyze risk and uncertainty associated with incorporating energy efficiency as a resource in electricity planning.

4. Case Studies

To illustrate how consistency with the principles discussed in Chapter 2 may alter utilities' and ISOs or RTOs current approaches, this chapter provides case studies from diverse states that employ a range of approaches that allow efficiency to complete with all other electricity system resources (Figure 5).

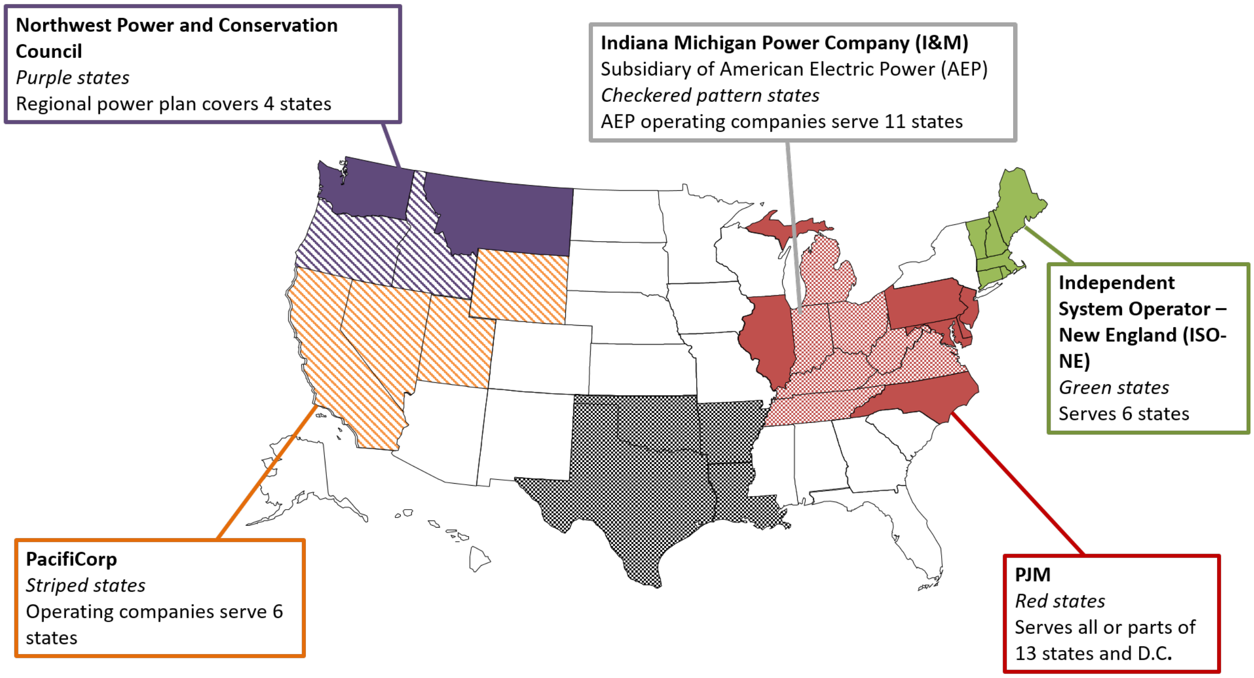

Figure 5. Utility and ISO/RTO Case Studies in this Report

The first case study is from the Northwest Power and Conservation Council. It provides a detailed discussion of including efficiency as a resource in all four of the electricity system planning elements. The second case study reviews ISO-New England and PJM's use of efficiency in their load forecasts and capacity auctions. The third and fourth case studies use I&M Power's 2019 IRP and PacifiCorp's 2019 IRP to examine two investor-owned utilities' use of efficiency as a resource in planning. Each case study begins with a summary of the elements discussed.

4.1 Northwest Power and Conservation Council

Summary of Four Elements of the Northwest Power and Conservation Council's Seventh Power Plan

- *Load forecasting:* The Council's model uses comparable granularity and technology detail on the supply- and demand-side. End-use categories, unit counts, and starting efficiency levels are consistent with the assumptions in the efficiency resource potential assessment.
- *Resource potential assessment:* The Council's resource potential assessment is consistent with load forecasts in fidelity and granularity and with respect to costs, load profiles, development lead times, and maximum annual availability. The Council first estimates technical potential and then takes into account market barriers to determine the achievable potential.
- *Capacity expansion modeling:* The Council's model characterizes efficiency with parameters that generally mirror those used to describe generating resource options and embodies specialized logic to address specific characteristics that are unique to energy efficiency resource deployment. Energy efficiency is treated as a resource option and competes with generation in the optimization.
- *Risk and uncertainty:* The Council's planning process recognizes that energy efficiency has a different risk profile than other resources have on the utility system, and conducts stochastic analysis to determine and incorporate efficiency's risk management benefits.

4.1.1 Background

The 1980 Northwest Electric Power Planning and Conservation Act (Power Act) authorizes Idaho, Montana, Oregon, and Washington to form the Northwest Power and Conservation Council (the Council), an interstate compact (16 U.S.C. Chapter 12H). The Power Act requires the Council to develop, with broad citizen participation, a regional power plan (as well as a fish and wildlife program). The Council develops a 20-year regional power plan that it reviews and revises every five years. Its objective is to set forth a resource strategy that ensures an "adequate, efficient, economical and reliable power supply" at the lowest cost. The plan guides the Bonneville Power Administration's (BPA) resource decision-making, and the Council is required to approve any new BPA energy resource acquisition greater than 50 average megawatts acquired for more than five years. The Council's regional power plan also serves as a reference document for the region's public and investor-owned utilities, state regulatory commissions, and energy agencies.

The Power Act also includes directives about resources the Council's planning should consider. Resources included in the plan must be cost-effective and should result in a resource strategy "to meet or reduce the electric power demand … of the consumers at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource." The Power Act defines system costs to include all costs of a resource over its useful life, including quantifiable environmental costs. To minimize the cost of its resource plan, the Council takes the "total resource" or "societal" cost perspective, i.e., the perspective of the region's consumers.[24] All quantifiable regional costs of a resource are included regardless of who pays the costs.

A key and innovative element of the Power Act was to define conservation (i.e., the more efficient use of electricity) as a resource. The Power Act directs the Council to give priority to cost-effective energy efficiency and requires that energy efficiency be given a 10 percent cost advantage for planning purposes.[25] Cost-effective renewable resources are the Power Act's second priority resources, followed by generating resources utilizing waste heat or generating resources of high fuel conversion efficiency. The Power Act gives lowest priority to all other resources in developing the plan.

Defining efficiency as a resource has widespread implications for the Council's planning methods. Treating efficiency as a resource affects the Council's approach to electricity demand forecasting, electricity and natural gas price forecasting, the assessment of the potential for cost effective energy efficiency that utilities can acquire over the life of the plan, and how it evaluates a least-cost resource portfolio. The Council's approach to these planning functions has evolved since adopting its first plan in 1983.

This case study describes the approach used in its most recent regional plan, the Seventh Power Plan, adopted in February 2016. The Council's current planning process is iterative. First, it creates an initial demand forecast based on a preliminary projection of electricity prices. Next, it develops an assessment of a least cost resource strategy to meet the demand. The resource strategy—which includes efficiency improvements—changes electricity prices because the cost of generating resources and the amount of electricity sales through which the costs are recovered are both changed. If the resource strategy electricity prices are different from the preliminary electricity price assumptions, demand changes and the process starts again. This iterative process continues until the beginning and ending prices are close enough to make little difference. Figure 6 provides an overview of the Council's planning process.

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[24] The Power Act's cost-effectiveness test is a hybrid of the societal cost test and the total resource cost test described in the "California Standard Practice Manual for Economic Analysis of Demand-Side Programs and Projects." The Power Act directs the Council to include all power system costs and benefits associated with a resource, including quantifiable environmental costs and benefits that are directly attributable to a resource.

[25] The Congressional intent of including the 10 percent cost advantage for energy efficiency in the Power Act is unknown. However, it *is not* intended to serve as a proxy for efficiency's lesser environmental impacts or risk, since both of these factors are explicitly dealt with by other provision in the statute.

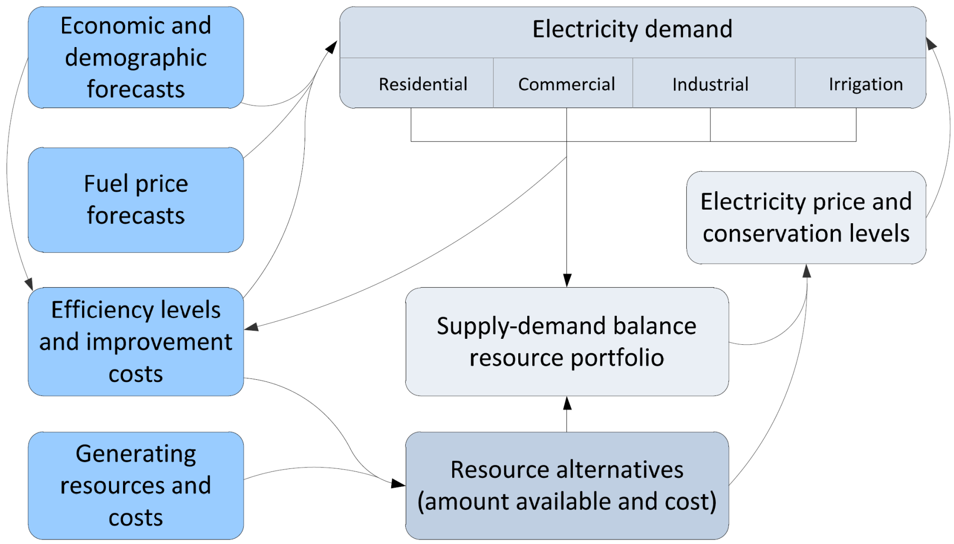

Figure 6. Overview of the Council's Planning Process

The Council uses several models in this process. It uses the Demand Analysis System to assess demand for electricity, natural gas, oil, and coal and provide many of the inputs required to estimate the remaining potential for energy efficiency. It uses the AURORA™ Electric Market of Model[26] to forecast wholesale electricity market prices at different points in the Western Electricity Coordinating Council (WECC) area. The GENESYS model provides a detailed assessment of the capabilities of Pacific Northwest electricity system, with particular focus on the capabilities of the region's large hydroelectric system. The Council also uses GENESYS to evaluate the adequacy of the Northwest power system. The Council developed its own capacity expansion model, the Regional Portfolio Model (RPM)[27] to conduct its analysis to determine the resource strategy for the Council's Power Plans.

The following sections discuss the planning process and the roles of these models in more detail, and describe how they enable complete and thorough treatment of energy efficiency as a resource.

4.1.2 Load Forecasting

The Council uses an end-use econometric forecasting model to explicitly capture the potential impact that *structural changes* (e.g., impact of known codes and standards, increased penetration of electric

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[26] Available from Energy Exemplar (https://energyexemplar.com/solutions/aurora/)

[27] The RPM is an electric integrated resource planning model used by the Council to identify adaptive, least-cost resource strategies for the region. The RPM uses a sophisticated and unique risk analysis methodology, developed by the Council, which involves simulating numerous candidate resource plans across a broad range of possible futures to identify trade-offs between expected cost and risk (See https://www.nwcouncil.org/regional-portfolio-model). The Council used the RPM to develops its Fifth and Sixth Northwest Power Plans. The Seventh Power Plan was based on the updated version of the RPM that takes advantage of cloud computing technology, newer optimization logic, and a programming platform that is more flexible and transparent.

vehicles, central air-conditioning, data centers, distributed generation) and changing long-term weather patterns could have on both the magnitude and shape of future loads. For example, the Council explicitly includes in its load forecast (and energy efficiency resource potential assessments) the impact of known federal appliance, lighting, and equipment efficiency standards, as well as state energy codes on future loads (NWPCC 2016). For the Seventh Power Plan, the Council also evaluated the potential impact of varying levels of data centers and EV penetration, including their potential impacts on the system load shape.[28]

The Council's load forecasts provide inputs to energy efficiency resource potential assessment (e.g., number of new and existing houses, appliances, commercial building space, energy use). It is structured so that the end-use categories, unit counts and starting efficiency levels in the load forecasting model are consistent with the assumptions in the efficiency resource potential assessment.

The Council produces three types of forecasts: (1) price effects, (2) frozen efficiency, and (3) sales for a range of future economic conditions (e.g., low, medium low, medium, medium high, and high).[29]

The Council's *price effects* forecast is comparable to the traditional utility load forecast, and it is included in the Council's plan to satisfy the statutorily required 20-year forecast of electricity sales.[30] It assumes a range of expected economic growth and future energy price assumptions to project load growth over a 20-year period. The price effects forecast reflects the impact of several factors on future electricity demand:

- Consumer response to changing energy prices (e.g., changes in the efficiency of equipment and buildings, changing usage patterns, and changes in fuel choice for some end uses)
- Existing energy codes and appliance standards
- Known changes to those codes and standards
- Future energy demand of stock turnover (i.e., new, more efficient appliances replacing older, less efficient appliances).

The second type of load forecast is referred to as a *frozen efficiency* forecast, and assumes that the efficiency level is fixed at the base year of the plan. The factors considered in the price effect forecast could potentially duplicate part of the efficiency potential that is estimated as a resource option in the capacity expansion modeling, so the Council's frozen efficiency forecast only includes efficiency improvements resulting from stock turnover and known codes and standards.

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[28] Seventh Northwest Power Plan, Appendix E: Demand Forecast (https://www.nwcouncil.org/sites/default/files/7thplanfinal_appdixe_dforecast_4.pdf)

[29] Beginning with its first plan in 1983, the Council has used a range of future load growth to represent risks created by load forecast uncertainty. Because energy efficiency resources have different characteristics than fossil fuel generating resource options (e.g., no fuel cost, no carbon emissions), uncertainty about the future enables the Council's planning process to capture and evaluate the relative risk of energy efficiency vis-à-vis other resource options. Failure to acknowledge such uncertainty (i.e., the assumption of perfect foresight) would not differentiate resources that have dissimilar risk profiles.

[30] In addition to average annual electricity use, the Council also forecasts peak loads, seasonal, and hourly load profiles. These end-use patterns are important for assessing the effect of efficiency changes on peak loads and seasonal energy demand.

To ensure that all remaining energy efficiency potential is only represented as a resource option in the capacity expansion modeling process, the frozen efficiency forecast excludes savings from:

- Efficiency improvements that might result from existing programs
- Technical efficiency improvements due to price effects from the demand forecast

Including these efficiency improvements in the load forecast (thus reducing demand) and also in the assessment of remaining energy efficiency resource potential would be double counting. The Council addresses this problem by assuming that future electricity prices and efficiency levels (except those that change due to stock turnover or codes and standards) remain at their current levels throughout the planning period. The frozen efficiency forecast serves as the basis for the range of load forecasts used as inputs to the Council's Regional Portfolio Model and assessment of remaining efficiency potential.

The third type of forecast used in the Council's planning process reflects the impact on future loads of the efficiency resources chosen in the Council's preferred resource strategy, and occurs at the end of the planning process. It is referred to as the *sales forecast*, and it reflects the *net load growth* anticipated to occur, assuming that all cost-effective energy efficiency selected in the Council's preferred resource strategy is developed. The rationale behind this forecast is that by including all cost-effective efficiency levels into the load forecast model, the model can estimate any significant take-back effects that might reduce the expected net savings from an efficiency measure. This sales forecast is recommended by the Council for use in transmission and distribution system planning, because it represents the expected consumption of electricity after achieving the efficiency improvements recommended in the resource strategy.

4.1.3 Resource Potential Assessments

The Council's energy efficiency resource potential assessments are designed to characterize energy efficiency at the same level of fidelity and granularity as supply-side resources with respect to costs, load profiles, development lead times, and maximum annual availability. For example, the end-use load shapes used by the Council in the potential assessment portray the system impacts of efficiency at the same granularity (e.g., end uses versus sectors) and fidelity (e.g., hourly, on-peak versus off-peak hours) as the models used to determine the preferred resource strategy. For its capacity expansion model, the RPM, the Council represents the impact of energy efficiency based on coincidence with peak hour demands by season, determined by its analysis of hourly end-use load shapes.

The first step in the Council's energy efficiency resource potential assessment is estimating the technical potential. This is a comprehensive assessment of hundreds of potential efficiency improvements in specific applications in the residential, commercial, industrial, and irrigated agriculture sectors. The analysis also includes improved efficiency in utility distribution systems to reduce line losses. The Seventh Power Plan evaluated approximately 1,400 different efficiency measures. For each specific efficiency measure, estimating the technical potential includes:

- determining a baseline efficiency level,

- ensuring this baseline is consistent with the frozen efficiency load forecast,
- identifying the potential efficiency levels attainable with better technology and estimating their incremental cost,
- establishing the number of applications/units that the efficiency measure could be applied to, and
- assigning temporal savings patterns (i.e., load or savings shapes) to technologies over seasons and times of day.

The second step in the Council's process is to determine the levelized total resource cost of technically feasible efficiency measures. The Council estimates the cost to install and operate a measure, as well as its program administrative costs, over the entire planning period. To ensure that the total cost of efficiency resources is accurately reflected in its energy efficiency resource potential assessments, the Council's planning process captures the impact of these utility system and non-utility benefits that are not included in its capacity expansion modeling process. For example, the RPM does not directly assign a value to deferred transmission or distribution infrastructure investments that may result from lower future peak demands due to the impact of energy efficiency. Therefore, it applies a "cost credit" for transmission and distribution deferrals to each efficiency measure, the magnitude of which depends on its impact on coincident system peak demands.

The Council also attempts to capture other non-utility system costs and benefits of efficiency (e.g., water savings, operation, and maintenance savings) that are included in the Council's cost-effectiveness tests but not captured in the capacity expansion modeling process. If the Council expects an efficiency measure to affect other costs (e.g., through interactive effects) and it can estimate these changes, the Council accounts for the impact in its calculations. For example, improved lighting in a commercial building may result in higher heating costs and lower cooling costs due to less waste heat from the lighting. On the other hand, a more efficient clothes washer will reduce water heating costs and water use. Finally, to ensure that the cost of maintaining savings for a full 20-year planning period are accounted for, the initial cost of efficiency measures that have an effective useful life shorter than the 20-year planning period the Council are increased to reflect the present value cost of future resource replacement.[31]

The third step is to determine how much of the identified technical potential is achievable. This process establishes annual maximums, year-over-year ramp rates, and the cumulative limits to achievable development. The Council's assumptions regarding the pace and ultimate limits to achievability vary depending upon whether the measure is categorized as a lost-opportunity or retrofit (discretionary) efficiency resource.

[31] The Council uses a life-cycle cost accounting model, ProCost, to calculate the levelized cost of energy efficiency measures. This model, along with a user's guide, are available for download at: https://rtf.nwcouncil.org/work-products/supporting-documents/procost

Lost-Opportunity and Discretionary Efficiency Resources

The Council's approach recognizes that many efficiency improvements are only cost-effective during construction of new buildings or replacement of existing appliances or equipment. It categorizes such efficiency improvements as *lost-opportunity investments*. Their timing links to economic growth, which drives new building construction. For lost-opportunity efficiency measures, the Council assumes market penetration increases gradually over time, so that approximately 65 percent of the technical potential is achievable during the 20-year planning period.

A second category of efficiency improvements are those that are cost-effective to develop at any time, such as retrofits of existing buildings. These are referred to as *discretionary* efficiency resources, because implementers can schedule their development, although usually within certain limits. For retrofit measures, which can generally be acquired at any time, the Council typically assumes that 85 percent of the technical potential can be achieved over the 20-year planning horizon.

In addition to variations in degree of achievability, the Council accounts for variations in the amount of lost-opportunity efficiency achievable potential that is tied to economic growth, so that in higher load growth scenarios there is greater potential than in lower load growth scenarios. The Council does this by linking the number of applicable units used to calculate lost-opportunity potential to the corresponding frozen efficiency load forecast.

The Council treats energy efficiency as a resource, so its assumptions regarding maximum achievable potential do not assume consumer economic barriers to adopting measures that are cost-effective based on their value as utility system resource.[32] The Council only considers non-cost barriers (e.g., lack of information about the efficient technology) in the derating of technical potential to achievable potential. The Council's review of historical energy efficiency achievements in the Northwest region, as well as demonstrated program accomplishments, support its assumptions regarding the share of technical potential that is achievable over a 20-year planning period (NWPCC 2007).

4.1.4 Capacity Expansion Modeling

The Council allows efficiency to compete directly with generating resource options in the capacity expansion modeling optimization process, which identifies the preferred resource portfolio to determine if it is cost-effective.[33] This section discusses how the Council creates conservation supply

[32] Those measures where the value of the utility system savings is equal to or larger than the incremental cost of the measure.
[33] A more typical utility planning practice is to deduct a fixed amount of energy efficiency from the load forecast prior to determining the need for additional generating resources in a capacity expansion model. The amount of energy efficiency deducted from the forecast has been found to be cost-effective by comparing its cost to the "avoided cost" of a specific generating resource option or options. This approach assumes that the development of energy efficiency does not materially affect the type, timing, or amount of generating resources needed, thus changing the forecast of "avoided cost."

curves, which are the efficiency inputs to the capacity expansion model, and the Council's capacity expansion model.

Energy Efficiency Supply Curves

Before efficiency resources can be included in its resource strategy and plan, the Council screens these resources for cost-effectiveness. Since its first plan, the Council has treated energy efficiency as a resource option in its capacity expansion modeling process to screen it for cost-effectiveness by competing directly with generating resource options in the "optimization" process. In order to treat energy efficiency as a resource option, its capacity expansion model, RPM, characterizes efficiency with parameters that generally mirror those used in the model to describe generating resource options (e.g., levelized cost, energy and capacity output, development lead times). The Council also developed specialized logic in the RPM to address specific characteristics that are unique to energy efficiency resources deployment.

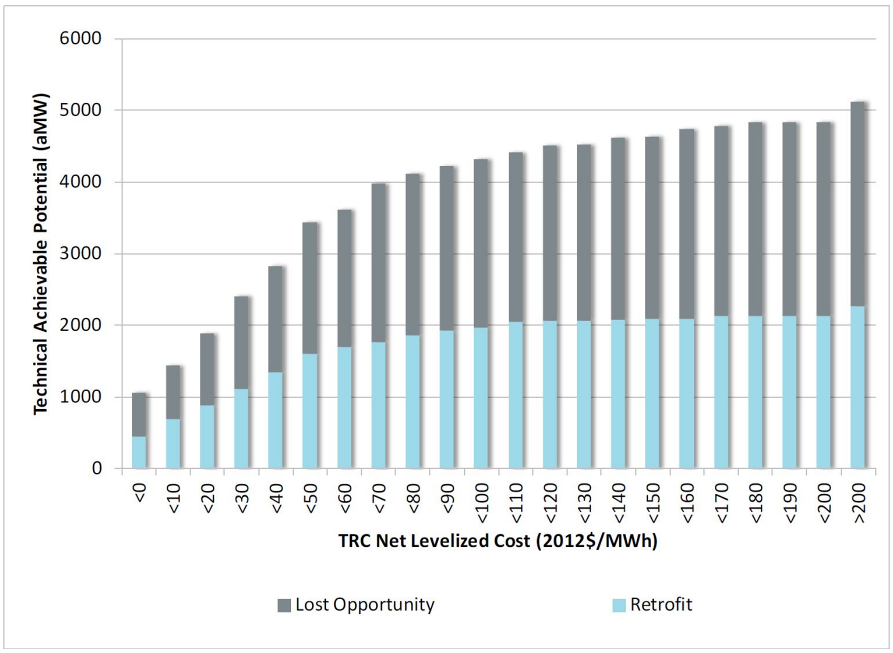
The Council aggregates its detailed assessments of achievable energy efficiency into two separate supply curves for input into the Council's RPM. An energy efficiency supply curve represents how much energy is available at different cost levels during each decision interval of the planning period.[34] The Council's energy efficiency supply curves are an aggregation of the achievable savings and levelized costs of individual measures bundled into specific levelized cost blocks or bins. As levelized costs increase, more measures become available. In order for RPM to identify the level of energy efficiency that is cost-effective, the supply curves for the achievable potential of retrofit and lost-opportunity potential include the total resource net levelized cost of energy efficiency. Their levelized cost reflects adjustments described in section 4.1.3 to reflect the cost of program administration, credit for transmission and distribution investment deferrals, and other non-energy system benefits not captured in RPM's economic analysis.

The Council creates separate achievable potential supply curves for retrofit and lost-opportunity efficiency resources for use in the RPM. One supply curve represents the achievable potential for lost-opportunity efficiency resources. The amount of efficiency available in this supply varies over time, determined by economic activity that drives new building construction and replacement rates for appliances and equipment. Because of variations in economic growth, there is a separate lost-opportunity supply curve for each year of the analysis and for each load growth forecast scenario. The RPM contains logic and inputs that map the load growth paths used in the RPM to its lost-opportunity potential.

The Council's second energy efficiency supply curve, the retrofit curve, aggregates the achievable savings from measures that can be implemented at any time. Although retrofit savings could be

[34] The RPM makes "decisions" regarding the level of energy efficiency to develop on a quarterly basis. Every three months, the model's acquisition logic compares the cost and availability of energy efficiency resources with the cost of competing resources to determine which resource to acquire.

acquired at any time, the Council places limits (e.g., maximum megawatt-hours per year) on their annual deployment rate to reflect the feasible scale of efficiency programs.[35] Because the availability of lost-opportunity and retrofit efficiency resources differs through time, the Council places separate restrictions on the ability of the RPM to deploy each of these resources to reflect their different constraints on development. Figure 7 shows the Council's energy efficiency supply curves from its Seventh Power Plan. This figure depicts the achievable potential by levelized cost bin for the Council's medium load growth forecast across its full 20-year planning period.



Total Resource Cost (TRC)

Figure 7. Energy Efficiency Supply Curve for Seventh Northwest Power Plan

Regional Portfolio Model

The Council's capacity expansion model, the Regional Portfolio Model (RPM), characterizes efficiency with parameters that generally mirror those used in the model to describe generating resource options (e.g., levelized cost, energy and capacity output, development lead times).[36] The model uses both reliability criteria and economic optimization logic to identify preferred resource portfolios, including

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[35] The Council also found that setting maximum annual limits on the deployment of retrofit measures is necessary because the retrofit supply curve contains significant achievable potential available at a levelized cost below short-run market prices and the dispatch cost of some existing resources. If annual limits on retrofit resource development were not imposed, the capacity expansion model would develop all retrofit measures with levelized cost below these thresholds during the first year of the planning period. For example, in the Seventh Plan, nearly 1,000 average megawatts of achievable retrofit potential are available at a levelized cost of 2.0 cents per kilowatt-hour (see Figure 2). Without limits, the capacity expansion model would call for the development of all of this potential in a single year if market prices were just slightly above 2.0 cents per kilowatt-hour or if existing resources had variable dispatch cost above that level.

[36] The Council's RPM includes energy efficiency and conventional supply-side resources, and also includes demand response, wind, and utility scale and distributed solar photovoltaic as competitive resource options in its analysis.

the amount and timing of energy efficiency resource development. The economic optimization criteria used in the RPM searches for the "lowest cost" resource portfolio, using the net present value of utility system revenue requirements as its cost metric. The RPM tests hundreds of alternative resource portfolios across wide range (800) of future conditions (e.g., load growth, fuel prices, market prices) to identify a resource strategy that has the lowest expected value cost with an acceptable level of risk.

Including energy efficiency as a resource option in the RPM alters the type, amount, and timing for the development of supply-side resources. As a result, the interaction of energy efficiency with supply-side resources produces an optimized resource portfolio from a wider array of resource options. These portfolios have a lower net present value system cost because the RPM can select efficiency resources that are less expensive to develop and have lower risk than supply-side options.

The Council also developed specialized logic in the RPM to address specific characteristics that are unique to energy efficiency resources deployment and to ensure unbiased competition between energy efficiency and other resource options. The RPM's logic finds the optimum type, amount, and timing for development of efficiency resources. It does this by testing alternative levelized cost levels (i.e., amounts), alternate schedules for development, and different combinations of retrofit and lost-opportunity efficiency resource development directly against new generation and market purchases in its optimization process.

The RPM bases its acquisition logic for energy efficiency on a target price relative to a smoothed two-year average of the previous simulated market prices.[37] This logic results in the RPM acquiring energy efficiency at a pace consistent with changing market conditions. However, simply purchasing energy efficiency that has a levelized cost below the smoothed two-year average market price would not test different strategies for acquisition. To ensure that a wide range of alternative levels of energy efficiency are tested, the RPM applies two "adders" to the market price in its optimization process—one for retrofit and one for lost-opportunity resources. The model purchases any available energy efficiency that has a levelized cost less than the smoothed two-year market price plus these adders. The RPM iterates on the size of these adders until it identifies the type (retrofit or lost-opportunity), timing, and amount of efficiency that results in the least cost resource strategy.

In addition to the specialized acquisition logic, the RPM also incorporates optimization logic for the treatment of lost-opportunity resources.[38] First, as the achievable potential for lost-opportunity resources varies as a function of the pace of economic growth, the RPM has logic that scales achievable potential to the specific load growth path it is testing. Second, the RPM has separate and unique maximum development rate input assumptions and acquisition logic for retrofit and lost-opportunity

[37] The RPM uses the AURORA market price forecast as the basis for generating a distribution of external wholesale market equilibrium prices forecasts, one for each of the 800 futures it tests. In the RPM the WECC wholesale market serves as a resource, although its quantity is capped.

[38] A more detailed description of the Council's RPM presented in Appendix L: Regional Portfolio Model of the Seventh Power Plan (https://www.nwcouncil.org/sites/default/files/7thplanfinal_appdixl_rpm_3.pdf).

resource types. For lost-opportunity measures with expected useful lifetimes less than the planning period, the RPM resource expansion logic and inputs allow it to acquire savings not initially selected. This allows the RPM to develop a lost-opportunity measure. This may occur because the measure was not cost-effective or because the assumed limits to achievability excluded it when the measure was initially available.[39] Third, it also contains logic to address the possibility that efficiency programs might be ramped up or down depending on their perceived cost-effectiveness.

4.1.5 Modeling Uncertainty and Risk

The Council's planning process recognizes that energy efficiency has a different risk profile than other resources have on the utility system. Relative to generating resources, energy efficiency presents no fuel price risk, does not emit carbon dioxide or other air pollutants subject to regulation, and its development can better scale to resource need. To evaluate energy efficiency's impact on utility system economic risk relative to other resource options, the Council explicitly recognizes in its planning process that the future is unpredictable. The Council's approach to building a preferred resource strategy incorporates the inherent uncertainty of the future.

The objective of the Council's resource strategy is to avoid exposing the Northwest region to the risks of very high-cost futures, while seeking an adequate, reliable, and low-cost power system. Achieving this objective requires a non-traditional approach to planning, one that focuses not just on the cost of the power system under specific scenarios but one that also identifies major economic risks to the power system and develops strategies to quantify and mitigate those risks.

The Council developed its own model (the RPM) to address the uncertainty of long-term trends in electricity demand, fuel prices, and variable hydroelectric condition. Unlike most electricity capacity expansion planning models, the Council's RPM does not evaluate resource strategies with foreknowledge of future conditions (i.e., perfect foresight). This is a critical feature for treating energy efficiency as a resource because different resource strategies can be tested for their robustness as alternative futures unfold, and the resource choices made result in differing costs to the power system.[40]

The Council's RPM evaluates the cost and economic risk of each candidate plan that it considers to 800 future conditions to determine how costs vary across those conditions. The 800 futures consist of random draws of uncertain future conditions over a 20-year time span that include electricity demand

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[39] For example, the RPM might not select a heat pump water heater as a cost-effective measure in the initial years of the Council's 20-year analysis. However, towards the end of this same planning period—when the option to select this water heater occurs again—avoided costs for other resource options might be high enough to make acquisition of the heat pump water heater cost-effective. Without this logic in the RPM, the lost-opportunity resource potential would be lower.

[40] In contrast, in perfect foresight capacity expansion models the pace of future load growth, fuel, and market prices are known, and resource development strategies can be optimized for that specific future. Even when hundreds of different futures are tested, these models find the optimized resource portfolio for each of those futures. Since there are no unanticipated departures from the assumed future conditions, energy efficiency's ability to reduce risk stemming from variations in fuel or market prices or the pace of load growth cannot be evaluated.

growth, natural gas prices, wholesale electricity prices, hydro conditions, resource costs and outages, carbon pricing levels, and renewable energy incentives. Some of the uncertain variables correlate to each other (for example, high natural gas prices tend to result in higher electricity prices, poor water conditions tend to cause higher electricity prices, and inadequate electricity resources are likely to lead to an increased incidence of high electricity price events).

From the 800 futures, two key measures are extracted. One is the average net present value of power system costs across all 800 futures. The second is an economic risk measure that consists of the average cost of the highest 10 percent of the net present value cost results across the 800 futures.

The variation in these uncertain conditions is not limited to different long-term trends. There are also cycles lasting several years and volatility on a shorter-term basis. For example, the RPM creates short-term market price spikes that might reflect a drought and associated wildfires over a single season or year. It also creates longer term price trends that might be caused by market disruptions such as the West Coast energy crisis, which lasted several years. As different futures unfold, resource strategies tested in the RPM turn out to be good or bad. By searching through thousands of possible resource strategies or plans and documenting how each one performs in terms of its costs under hundreds of future scenarios, the Council identifies an optimal strategy that achieves the desired level of risk protection at the lowest possible cost for the regional power system.

The Council believes that capturing the impact that variations in future conditions have on a given set of resource decisions is important because some resources are greatly affected by these changes while others, like energy efficiency, are more robust. The RPM’s analytical structure allows the Council to evaluate different resources, including energy efficiency, to identify those characteristics that create or reduce risk.

Resource characteristics that tend to mitigate risk are intuitive, but traditional “perfect foresight” analysis cannot quantify them. Resources favored by the RPM include low-cost resources that are resilient to fuel price volatility, carbon policy, and demand forecast errors. In addition, resources that have short lead times or develop in small increments have less capital risk in case of unexpected changes in supply and demand. Efficiency improvements score well on both counts. Efficiency is low cost, uses no fuel, emits no carbon, and can defer or eliminate transmission expansion.

4.2 ISO-New England and PJM[41]

Summary of Two Elements of Efficiency in the Independent System Operator-New England and PJM Electricity Markets

- *Load forecasting:* ISO-NE and PJM both increase their load forecast to account for efficiency and allow it to participate as a resource in the RTO's respective capacity auctions.
- *Capacity expansion modeling:* Neither entity conducts expansion modeling, instead employing capacity auctions into which efficiency resources can be bid, competing with generation. The benefits from efficiency are partially monetized.

4.2.1 Background

U.S. ISOs and RTOs serve two-thirds of the nation's electricity load.[42] They engage in two types of system planning: their near-term planning focuses on *resource* adequacy while their long-term planning addresses *transmission* reliability. Here, we discuss the role of efficiency in resource adequacy in ISO-New England (ISO-NE) and PJM.

Resource adequacy planning establishes the quantity of resources needed to meet peak load demand while complying with applicable reliability standards and standard electric industry practice.[43] Resource adequacy planning looks out over a short horizon, usually one to three years, and uses the single criteria of forecasted peak loads to determine if sufficient resources are available. The analysis does not attempt to identify or select any specific resources or a resource mix, it only identifies the necessary total resource quantity. Wholesale energy and ancillary services markets, as well as the capacity structures discussed below, are where the specific resource determinations occur.

This section uses ISO-NE and PJM as examples of how centrally organized wholesale markets consider energy efficiency as a resource in load forecasting and capacity auctions. We focus on these entities because both allow energy efficiency to participate as a resource in their respective capacity markets and account explicitly for its impacts in their planning processes. ISO-NE is the RTO that serves the six New England states (Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont). PJM is the RTO that serves all or parts of 13 U.S. states (Delaware, Indiana, Illinois, Kentucky, Maryland,

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[41] Paul Peterson and Jennifer Kallay, Synapse Energy Economics, Inc. prepared the PJM case study.

[42] For more information on RTOs and ISOs, see https://www.ferc.gov/industries-data/market-assessments/electric-power-markets

[43] Resource adequacy planning is different from, but related to, transmission system planning. Transmission system planning incorporates load forecasts that estimate peak loads 10 or more years into the future and evaluates how the electric grid will perform across a broad range of criteria that include variable load forecasts and system conditions regarding thermal, voltage, and stability issues. The purpose of transmission planning is to identify reliability issues at specific locations that will need to be resolved with transmission upgrades. The purpose of resource adequacy planning is to ensure that there is a sufficient quantity of resources to meet annual peak loads (for most regions this is the summer peak load, but many systems evaluate both summer and winter peak loads due to seasonal variations in the mix of available resources).

Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia) and the District of Columbia.

4.2.2 ISO-NE Load Forecast

ISO-NE's load forecast estimates the energy and demand for 10 years for the six states they serve. The forecast is used for power system planning and reliability studies. The gross load forecast reconstitutes the load-reducing impacts of efficiency, distributed generation (DG), and behind the meter photovoltaics (BTMPV), while the net load forecasts do not (ISO-NE 2019). The gross and net load forecasts begin with the historic net energy load (NEL) and include the load reducing impact of price responsive demand (PRD) (Figure 8).

Net Load	Gross Load
$Load_{Net} = NEL + PRD$	$Load_{Gross} = NEL + PRD + EE + DG + BTMPV$

Figure 8. Net Load and Gross Load Definitions (ISO-NE 2019)

To determine the efficiency values used to reconstitute the gross load forecast, ISO-NE estimates monthly and hourly energy efficiency impacts. Impacts reported in monthly program administrator efficiency performance submissions are the starting point for ISO-NE's estimates. Using a three-year average of monthly load factors, monthly average weekday efficiency performance, and number of hours in the month, ISO-NE estimates the monthly efficiency and then increases it to account for transmission and distribution losses. The hourly impacts are estimated using the monthly peak megawatt reduction and grouping hours into four bins (on-peak and off-peak weekday and weekend) and multiplying the savings in each bin by a factor. Because ISO-NE allows energy efficiency to participate as a resource in its capacity auction, the forward capacity market (FCM), the reconstituted gross load forecast is used to determine the target quantity of resources the FCM will purchase to avoid double counting efficiency.[44]

4.2.3 PJM Load Forecast

PJM produces an annual load forecast for the entire PJM footprint, as well as sub-regions within that footprint, used in its resource adequacy planning.[45] The forecast is a combination of several different elements, one of which represents consumer load reductions from energy efficiency measures. The PJM Load Analysis Subcommittee holds several stakeholder meetings each year to review the load forecast model inputs and the forecast model itself. The Subcommittee adjusts both annually.

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[44] ISO-NE is will new an updated reconstitution methodology in its 2021 Capacity, Energy, Load and Transmission (CELT) report.

[45] The PJM planning process for bulk system upgrades produces an annual Regional Transmission Expansion Plan (RTEP) report that looks at system upgrades needed over a five-year and a fifteen-year horizon. PJM RTEP reports can be found at: https://www.pjm.com/planning/rtep-development/baseline-reports.aspx.

Beginning with the 2016 forecast, the Load Analysis Subcommittee implemented a statistical-based (SAE) model to estimate energy efficiency impacts on current and future loads for inputs into the analysis of the reliability of the bulk power system.[46] As described in its 2016 Load Forecasting Model Whitepaper, PJM begins with the Annual Energy Outlook produced by the U.S. Energy Information Administration (EIA)'s National Energy Modeling System (NEMS) (PJM 2016).[47] ITRON combines NEMS data with historical residential and commercial sector data it maintains to develop specific values for each census division. PJM uses the ITRON data to develop three categories of equipment indices: cooling equipment, heating equipment, and other equipment. PJM provides the indices for each utility region in the PJM footprint and for both the residential and commercial sectors.[48] PJM equipment indices account for all expected purchases whether achieved through a specific energy efficiency program or not.[49] In addition, individual utilities can provide their own information about saturation levels within their load zones to PJM, and an increasing number have done so over the past four years.

There have been five forecasts to date (2016 through 2020) that have relied on the equipment indices methodology, as supplemented by utility data. These forecasts have seen a reduction in annual variances (volatility). Regions that have sharp increases or decreases in energy efficiency investments or develop new codes can have those changes reflected in their specific forecasts by submitting the data to PJM. Overall, the equipment indices methodology produces a steady reduction in summer and winter peak loads as energy efficiency programs continue, and appear to be consistent with state, regional, and national studies that estimate energy efficiency trends.[50]

Ultimately PJM uses the load forecast, as adjusted by energy efficiency and other factors, as an input to the PJM planning process for evaluating all PJM regions for reliability and economic conditions that may warrant infrastructure investments.

[46] Prior to the 2016 load forecast, PJM largely relied on reporting from its load-serving utilities to estimate energy efficiency impacts on its peak load forecast used in planning. It assumed the utility load forecasts accounted for prior year energy efficiency installations. For RPM annual auctions, PJM adds energy efficiency resources that qualify for the auctions back to the load input used to establish the annual demand curve for the auction.

[47] EIA produces an annual Reference Case that estimates a business-as-usual trend for future energy consumption. EIA relies upon the NEMS to represent the impacts of equipment saturation and efficiency at the Census Division level across different sectors: residential, commercial, industrial, and transportation. Each NEMS module produces appliance saturation rates, replacement rates, and efficiency levels for the equipment in that module. NEMS data include the impact of national efficiency standards on the likely equipment choices in future years.

[48] ITRON provides data sets to members of its Energy Forecasting Group, which includes PJM.

[49] One simple example of market transformation is the enhancement to replacement windows. All replacement windows are a least double-glazed, low-emissivity glass, and they often have applied coatings as well; this applies to all window installations, whether the customer participates in an energy rebate program or not. Similar market transformations are occurring with appliances, too.

[50] ISO-NE, NYISO, MISO, and CAISO also develop estimates of energy efficiency trends for use in planning studies.

4.2.4 ISO-NE Forward Capacity Market

Rather than test the cost-effectiveness of alternative resource options through a capacity expansion modeling processes, ISO-NE and PJM operate three-year forward market-based mechanisms (i.e., auctions) that are designed to meet their resource adequacy needs with the lowest cost, reliable resource options. In the auctions, efficiency competes directly with generation resources to meet forecasted resource adequacy needs. Efficiency resources selected through these competitive bidding processes receive fixed monthly payments equivalent to those of selected generating resources.

The Forward Capacity Market (FCM) is the mechanism used by ISO-NE to ensure resource adequacy over the three-year planning cycle. The FCM is a competitive procurement process that allows offers from existing supply, new supply, and demand resources. ISO-NE sets a target quantity of resources that it will purchase (based on its forecast of summer peak load four years into the future) and a maximum price it will pay for that quantity of resources. It conducts an annual auction each February to purchase a sufficient quantity of resources to meet its expected capacity requirement for the power year that starts in June, three years into the future.[51] Efficiency offers to the FCM reduce electricity consumption in summer and winter hours (on-peak resources) or months (seasonal).

New energy efficiency resources must submit a qualification package that requires information on the energy efficiency source of funding (e.g., public benefits fund, private financing), a measurement and verification plan, and a customer acquisition plan that describes the efficiency measure target market and customer acquisition strategies.[52] Existing resources are qualified to participate in the Forward Capacity Auction based on their historical performance and remaining measure life as measured in both summer and winter seasons.[53]

4.2.5 PJM Reliability Pricing Model

The Reliability Pricing Model (RPM) is the mechanism used by PJM to ensure resource adequacy over a three year planning cycle. Similar to the ISO-NE FCM mechanism, the RPM facilitates a competitive procurement of existing and new supply resources based on offers. PJM sets a minimum quantity of resources that it will purchase and a maximum price it will pay for that quantity of resources. PJM conducts a sealed bid auction each May to purchase a sufficient quantity of resources to meet its expected peak load for the power year that starts in June, three years into the future.

PJM provides monthly capacity payments for the interim period (four years) between the time of measure installation and the time when the load reductions from the installed measures begin to be reflected in the historical (i.e., actual) metered load data on which the econometric load forecast for

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[51] The FCM designates the lowest-priced offers to clear the auction as capacity resources with capacity supply obligations. They receive fixed monthly payments for their capacity obligation. The auction mechanism allows ISO-NE to purchase more resources than the minimum it needs as long as the total cost (all purchases times the price) is lower than the preset minimum quantity at the maximum price.

[52] More information on demand resource participation in ISO-NE is available at https://www.iso-ne.com/markets-operations/markets/demand-resources.

[53] Market Rule 1, section III.13.1.4.2 (p. 64).

future years is derived. PJM uses this approach to avoid double counting the impacts of these resources in the load forecast used for the subsequent RPM auction.

4.3 Indiana Michigan Power Company (I&M)

Summary of Four Elements of Indiana Michigan Power (I&M)'s Integrated Resource Plan

- *Load forecasting:* I&M uses an end-use econometric methodology that includes naturally occurring savings from future energy efficiency and savings from previously approved efficiency programs in the load forecast.
- *Resource potential assessment:* I&M's consultant conducted a resource potential assessment using I&M specific costs, benefits, and energy efficiency programs. Energy efficiency supply curves are created using, in part, inputs from the resource potential assessment.
- *Capacity expansion modeling:* I&M uses the PLEXOS LT Plan (PLEXOS) capacity expansion model to compete a representative proxy of available energy efficiency resources with conventional generating resources and endogenously determine how much efficiency to acquire. I&M provides energy efficiency supply curve information to the model at the same level of hourly detail as supply-side options. I&M applies a degradation rate[54] to company sponsored energy efficiency resources (e.g., the measure would be adopted and considered as a reduction to the load forecast in the future regardless of I&M's energy efficiency program offerings).
- *Risk and uncertainty:* I&M does not explicitly consider risk associated with efficiency in its IRP. Risk analysis is included in its 2019 IRP in two ways. First, by using four commodity price scenarios to create resource plans under differing long-term pricing conditions, and second by using stochastic analysis on select cases to identify the distribution of possible outcomes.

4.3.1 Background

American Electric Power (AEP) Company operates in ten states as seven operating companies: AEP Texas (Texas), Appalachian Power (Virginia, West Virginia), Kentucky Power (Kentucky), Indiana Michigan Power (I&M) (Indiana and Michigan), Ohio Power (Ohio), Public Service Company of Oklahoma (Oklahoma), and Southwest Electric Power Company (SWEPCO) (Arkansas, Louisiana, and Texas) (Figure 9).

[54] "The initial base load forecast accounts for the evolution of market and industry efficiency standards. As a result, energy savings for a specific EE program are degraded over the expected life of the program." "Based on the energy efficiency (EE) bundle life, a degradation factor curve is applied. The company has developed 10-year- and 15-year EE life degradation factor curves to apply to the EE bundles included as resource options in the IRP. These degradation factor curves were developed by the company's load forecasting group to avoid double counting energy efficiency improvements already reflected in I&M's load forecasting methodology" (I&M 2019).

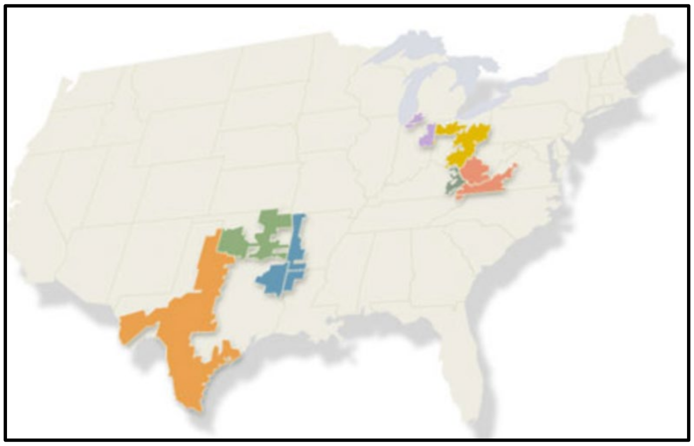

Figure 9. AEP Regulated Utility Service Territory

All seven AEP operating companies are regulated, investor-owned utilities, although the regulatory environment varies for each state (e.g., some can earn performance incentives for meeting energy efficiency goals). Most states that AEP operates in have regulatory requirements for integrated resource planning that must be taken into consideration (Figure 10).

INTEGRATED RESOURCE PLAN PROCESS

State Jurisdiction	AEP Operating Company	Filing Frequency	Planning Period	Stakeholder Input Process
Arkansas	Southwestern Electric Power Company	3 years	10 years	Yes
Indiana	Indiana Michigan Power Company	3 years	20 years	Yes
Louisiana	Southwestern Electric Power Company	4 years	20 years	Yes
Kentucky	Kentucky Power Company	3 years	15 years	No
Michigan	Indiana Michigan Power Company	5 years	20 years*	Yes
Ohio**	AEP Ohio	**	**	No
Oklahoma	Public Service Company of Oklahoma	3 years	10 years	No
Virginia	Appalachian Power Company	3 years	15 years	No***
West Virginia	Appalachian Power Company & Wheeling Power Company	5 years	10 years	No

* I&M's 2018/19 MI IRP filing will be prepared according to the Indiana Commission's IRP requirements as permitted by 2016 MI Public Act 341 Section 6 t (4).

** Integrated resource plan only required under special circumstances.

*** Virginia has a formal regulatory hearing, with public intervention, before the Virginia SCC for such IRP submittals.

Figure 10. AEP Integrated Resource Plan Requirements by State

This case study focuses on I&M, AEP's subsidiary operating in Indiana and Michigan. I&M serves 590,000 customers and owns 5,247 megawatts (MW) of generation. Both statute[55] and rules[56] in Indiana require utilities that own generating facilities to prepare an integrated resource plan.
The Indiana IRP rules require that utilities evaluate demand and supply-side options on a consistent and

[55] Indiana Code §8-1-8.5-3.

[56] Indiana Administrative Code (2013).

comparable basis. I&M filed its most recent integrated resource plan in Indiana in July 2019, and it is part of an ongoing proceeding (Cause Number 45285). Michigan also requires that utilities file an integrated resource plan. I&M filed its Michigan IRP in August 2019, and it is also an ongoing proceeding (Case number U-20591).

4.3.2 Load Forecasting

I&M develops two independent load forecasts models and uses a blending technique to create the final load forecast used in the IRP. Short-term load forecast models are used to create the load forecast for 24 months into the future, and long-term load forecast models are used to create the load forecast for the next 30 years. The blended forecast uses both the short-term and long-term forecasts models to address inconsistencies between the two models.

As part of its 2019 IRP, I&M developed base, high, and low scenarios to consider a range of possible futures for its energy requirements and for resource optimization (Figure 11). It also considered several supporting scenarios, three projecting alternative paths for energy efficiency, and one addressing extreme weather risk. The scenarios are described below.

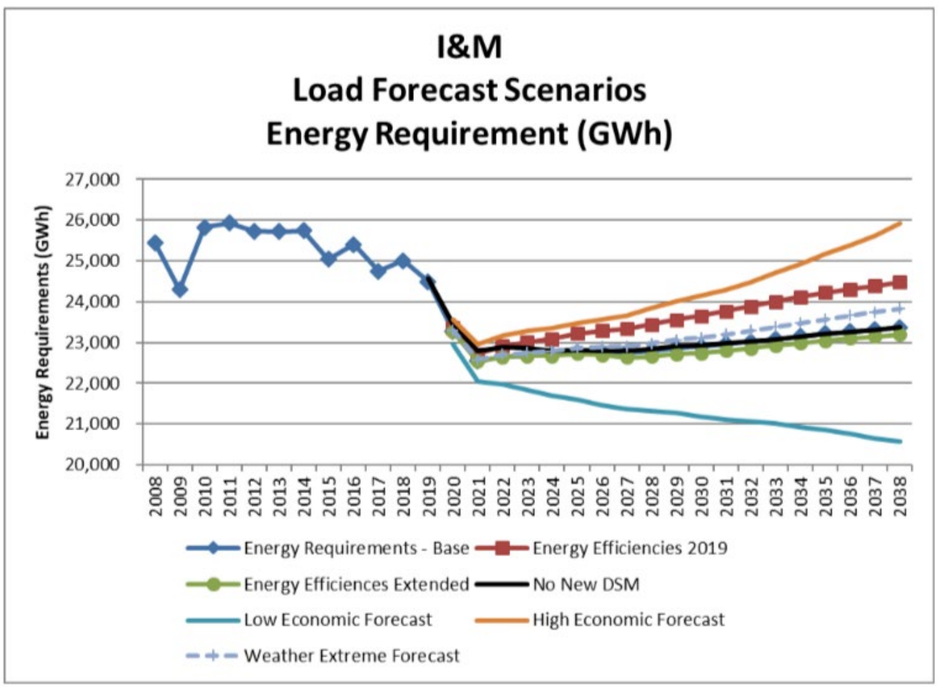

Figure 11. I&M 2019 IRP Load Forecast Scenarios (I&M 2019)

- No new demand-side management (DSM): DSM from future savings from approved programs that is otherwise included in the load forecast is removed. This scenario is higher than the base forecast.
- Energy efficiencies 2019: Residential and commercial equipment is kept at the 2019 energy efficiency levels. This scenario is higher than the base forecast.

- Energy efficiencies extended: Energy efficiency is procured at a faster pace than in the base forecast and is based on an EIA analysis. This scenario is lower than the base forecast.
- Weather extreme forecast: Winter and summer average daily temperatures are assumed to increase. This scenario is higher than the base forecast.

Historic energy efficiency and forecasted trends in appliance saturation and efficiency based on known appliance efficiency standards are modeled with Itron's proprietary statistically adjusted end-use (SAE) model, which AEP uses to determine customer sales by class.[57] This model forecasts energy consumption per residential customer and energy consumption per square foot for commercial customers. The SAE model assumes residential and commercial consumption is comprised of one of three end-use categories: heating, cooling, or other. The SAE model forecasts future energy use for each of these broad end-use categories using engineering principles and econometric relationships derived from historical data.

Existing energy efficiency plans that previously have been approved by regulatory commissions are modeled by adding in the impact of the programs and then removing efficiency that has already been captured in the SAE Model. I&M refers to this as a *degradation factor.* I&M's stated goal for using a degradation factor is to prevent double counting efficiency savings that are captured in both the existing energy efficiency plans and in the load forecast through Itron's SAE Model (Burnett 2020). The degradation factor is also used to account for a reduction in operational efficiency in appliances that occurs over time, market adoption rates, stipulated versus verified savings, and net to gross ratios (Burnett 2020). I&M's 2019 IRP applies the degradation factor to all existing and new efficiency savings. As discussed in the other case studies, an alternative to using a degradation factor (for the purpose of preventing double counting) is to exclude *all* future efficiency from the load forecast that is used for capacity planning.

4.3.3 Resource Potential Assessments

I&M developed resource potential for three types of energy efficiency resources: (1) traditional energy efficiency (customer-driven) resources, (2) demand response resources (including energy savings), and (3) grid optimization resources. In 2016, in preparation for its 2019 IRP, I&M conducted an energy efficiency potential study (Market Potential Study, MPS). The MPS identified technical, economic, maximum achievable and realistic achievable potential measure savings that are available from 2016–2036. I&M also identified three scenarios of program-level potential savings (Figure 12). Figure 13 displays the results of the MPS.

[57] Available from ITRON. Energy Forecasting. https://www.itron.com/na/industries/electricity/energy-forecasting.

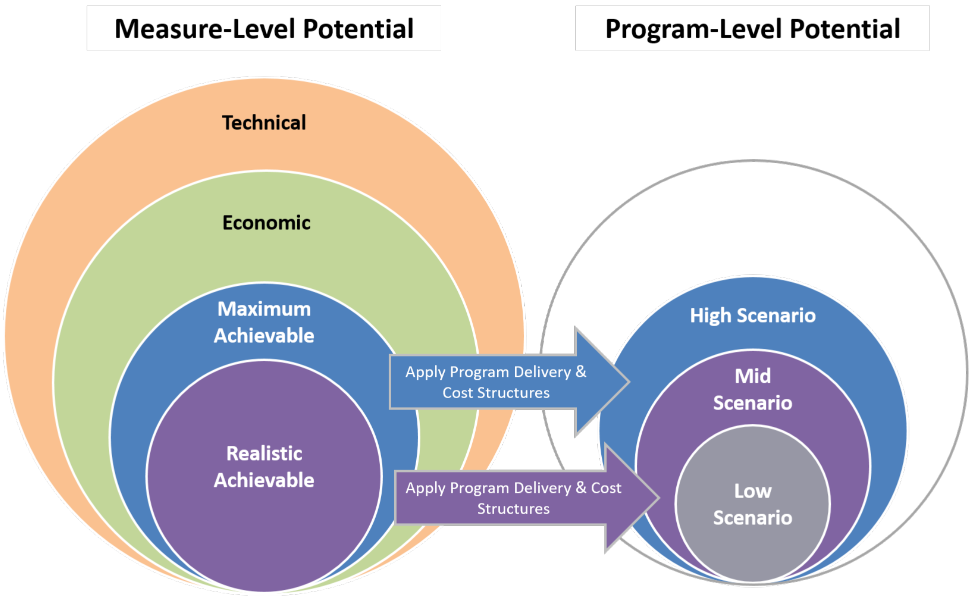

Figure 12. Relationship between Measure-level and Program-level Potentials

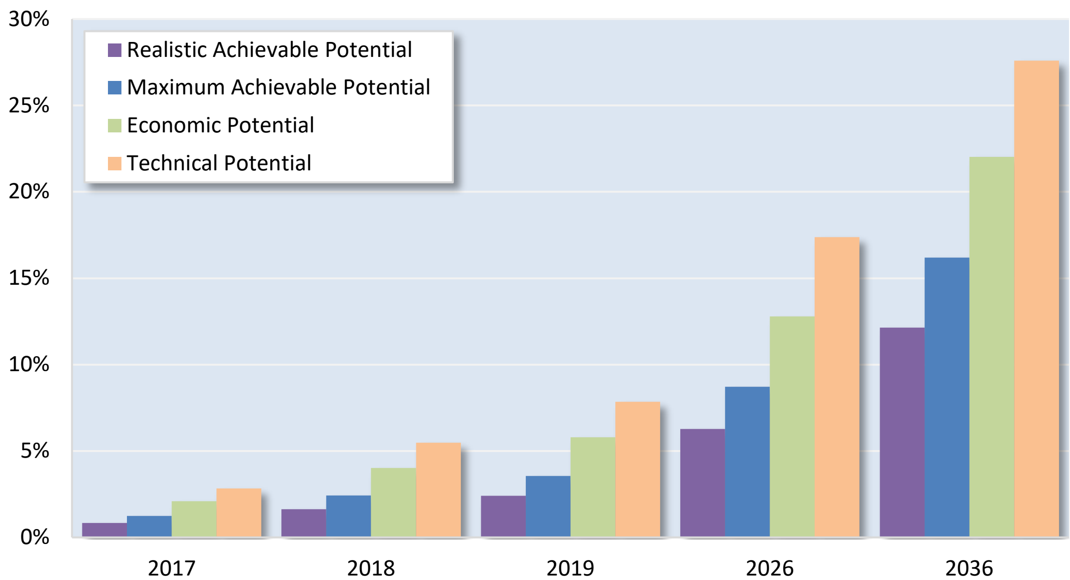

Figure 13. I&M Market Potential Study Results

I&M's MPS serves as the foundation for developing efficiency inputs to the company's IRP (AEG 2016). I&M's consultant, Applied Energy Group (AEG) conducted the company's MPS and used their model with I&M's avoided cost forecast to screen measures for cost-effectiveness. The model combines cost-effective measures (based on the utility cost test) into programs (i.e., bundles of related measures), which are also screened for cost-effectiveness (AEG 2016). The amount of savings available in programs that are determined to be cost-effective (i.e., economic potential) are then derated to forecasted maximum achievable and realistic achievable potentials.[58] The maximum achievable and realistic achievable potentials serve as inputs to the IRP.

Estimates of energy savings from the potential assessment are characterized as a percent annual reduction of the end-use affected by an efficiency measure. The potential study identifies peak demand impacts by calculating the fraction of the annual energy use identified as on-peak. These are derived from AEG's proprietary model, which uses end-use load shapes to determine peak demand.

4.3.4 Capacity Expansion Modeling

I&M (and more broadly AEP) primarily use the proprietary capacity expansion model, PLEXOS LT Plan (PLEXOS), to identify and rank portfolios to meet future load. [59] The PLEXOS model selects the portfolio with the lowest cost revenue requirements as its optimum or preferred resource portfolio. The PLEXOS capacity expansion model assumes perfect foresight. That is, because the model uses a single set of input assumptions for all of the factors that impact the outcome (e.g., load growth, future natural gas prices, the cost and availability of new generation, market prices) it can find the optimum (i.e., least cost) resource portfolio for the entire planning time frame for that specific future. To test the sensitivity of various input assumptions, I&M runs multiple scenarios with different forecast input assumptions for which PLEXOS identifies (with a perfect foresight) the optimum resource portfolio.

Two levels of efficiency resources were included in the PLEXOS model—realistically achievable and maximum achievable measure potential. These potentials are bundled together and included in the PLEXOS model as resource options that can be selected for development. If the model determines that some or all of the efficiency bundle is economic or least cost, it will include that quantity of efficiency in the portfolio of optimized resources.

Efficiency bundles were determined based on measure attributes from I&M's 2016 Market Potential Study. These attributes include the following:

- *End-use:* Bundles are created by grouping energy efficiency measures together by end-use load shape to serve as proxies in the model. In the 2019 IRP, I&M used 13 residential end-use bundles and 16 commercial and industrial end-use bundles (I&M 2019).
- *Measure life:* I&M assumes a measure life for each end-use bundle. The 2019 IRP bundles have measure lives that range from 1 year (behavioral measures) to 20 years (residential building shell measures) (I&M 2019). The publicly available portion of the potential study does not provide energy efficiency measure lifetimes (AEG 2016).
- *Energy and demand savings:* The market potential study provides annual energy and demand savings by end use and time period. For example, in the 2019 IRP, there are four time periods; 2020–2024, 2025–2029, 2030–2039, and 2040–2045 (I&M 2019).

[58] I&M's definitions of achievable potential are reduced quantities of its economic potential. This is a more narrow definition than what is provided in the glossary.

[59] Available from Energy Exemplar (https://energyexemplar.com/products/plexos-simulation-software/).

- *Incentive cost:* I&M splits end-use bundles into two categories. The first category, *achievable potential,* assumes that half of the measure incremental cost will be paid by the utility. The second category, *high achievable potential,* assumes that 75 percent of the measure incremental cost will be paid by the utility (I&M 2018).
- *Other program costs:* Other typical program costs are included to create a total utility installed cost, measured on a $/kWh basis. There is no detail on what is included in the installed cost (I&M 2018).
- *Degradation profile:* The degradation profile reduces savings from efficiency programs to avoid double counting savings that are incorporated into the load forecast.

I&M uses the cost-effective measures identified in its realistically achievable energy efficiency potential and the program costs from the company's existing energy efficiency programs as the primary inputs into the energy efficiency bundles. I&M groups the measures by load shape, weights them by the savings for each measure, and then assigns a kilowatt savings value, which is coincident with PJM's top five summer peaks, to each bundle. I&M creates bundles in five-year increments and then further divides the bundle savings into annual 1,000 megawatt-hour (MWh)/year units to reduce modeling time.

I&M then inputs the efficiency bundles into the PLEXOS capacity expansion model, with the annual quantity of potential available based on the potential study. The model selects resources based on levelized costs and ultimately selects resources that minimize the present value revenue requirement for the I&M system. If the PLEXOS model determines that all or a portion of an efficiency bundle is economic or least cost, I&M will include that quantity in the portfolio of optimized resources.

There are four inputs per bundle for the PLEXOS model: (1) maximum units that are allowed to be built in a year, (2) maximum megawatt capacity (based on the end-use load shape in the market potential study), (3) generation unit construction cost ($/kW), and (4) the firm capacity megawatt (based on the end-use load shape coincident peak) (I&M 2018). I&M characterizes the PLEXOS model's optimization of energy efficiency as follows:

> The Plexos software views demand-side resources as non-dispatchable "generators" that produce energy similar to non-dispatchable supply-side generators such as wind or solar. Thus, the value of each resource is impacted by the hours of the day and time of the year that it "generates" energy…. In this regard, they are "demand-side power plants" that produce energy according to their end use load shape. They have an initial (program) cost with no subsequent annual operating costs. Likewise, they are "retired" at the end of their useful (EE measure) lives (I&M 2019).

As discussed in section 3.2, the company also includes demand response and grid optimization resources supply curves.

4.3.5 Modeling Uncertainty and Risk

I&M does not explicitly consider risk associated with efficiency in its IRP. Generally, the company conducted risk analysis in its 2019 IRP in two ways: first, by using four commodity price scenarios to create resource plans under differing long-term pricing conditions; and second, by using stochastic analysis on select cases to identify the distribution of possible outcomes.

I&M creates a base, low, high, and no carbon case for each of their fundamental parameters: PJM on-peak energy prices, off-peak energy prices, capacity prices, natural gas and coal prices, and carbon dioxide prices. The present value of I&M's revenue requirement is calculated for each pricing scenario, for each portfolio. The results are used to identify insights about how resources perform under different commodity prices.

The company completes a "revenue requirement at risk" analysis that captures the impact of all resources, including energy efficiency on the portfolio's cost through a stochastic analysis. The output of the analysis is a distribution of outcomes that provides insights on the likelihood that a portfolio will exceed the higher end of its revenue requirements, or "revenue requirement at risk." The risk mitigation value of energy efficiency resulting from I&M's lower exposure to market price risk (due to variations in commodity prices) is captured in this analysis.

4.4 PacifiCorp

Summary of Four Elements of PacifiCorp's Integrated Resource Plan

- *Load forecasting:* PacifiCorp uses SAE modeling for residential load forecasting. It uses regression analysis for commercial and industrial but creates individual models for some of its large customers, and creates hourly forecasts for all sectors. It excludes future efficiency investments from load forecasts, which are instead treated as a resource in its capacity expansion modeling.
- *Resource potential assessment:* The utility identifies technical and achievable technical potential and creates energy efficiency supply curves.
- *Capacity expansion modeling:* Efficiency is selected through optimization with supply-side resources.
- *Risk and uncertainty:* PacifiCorp incorporates risk-reduction benefits of efficiency by including energy efficiency resources' impact on load growth when it determines its reserve margin and applies a stochastic risk reduction credit.

4.4.1 Background

PacifiCorp comprises two electric power utilities serving customers in six states: Pacific Power in California, Oregon, and Washington, and Rocky Mountain Power in Idaho, Utah, and Wyoming (Figure 14). The company completes a full IRP process every two years with updates every other year, and the most recent IRP was filed in October 2019. It files one IRP that applies to all six states in which it operates. The IRP has a 20-year horizon, with the primary objective of identifying the least-cost, least-risk portfolio (referred to as the "preferred" portfolio).

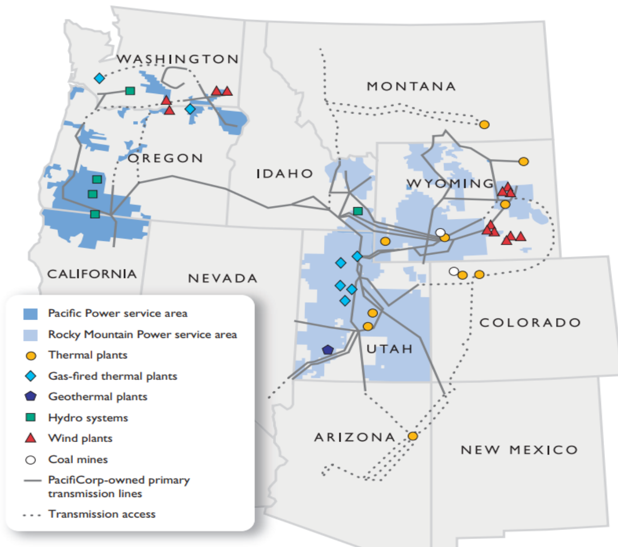

Figure 14. PacifiCorp Service Territory

The IRP is developed through a five-step process (Figure 15):

1. *Load and Resource Balance.* Compares a forecast of load to existing resources.
2. *Resource Portfolios.* Develops a range of different resource portfolios to meet deficiencies in the load and resource balance. Portfolio development takes into account the type, timing, and location of the new resources in the portfolio.
3. *Resource Portfolio Analysis.* Analyzes and compares the comparative cost, risk, reliability, and emission levels of the different portfolios.
4. *Preferred Portfolio.* Chooses a preferred portfolio based on the resource portfolio analysis identifying the least-cost, least-risk portfolio.
5. *Action Plan.* Devises an action plan to procure supply-side resources (including DSM resources) at the levels delineated in the preferred portfolio.

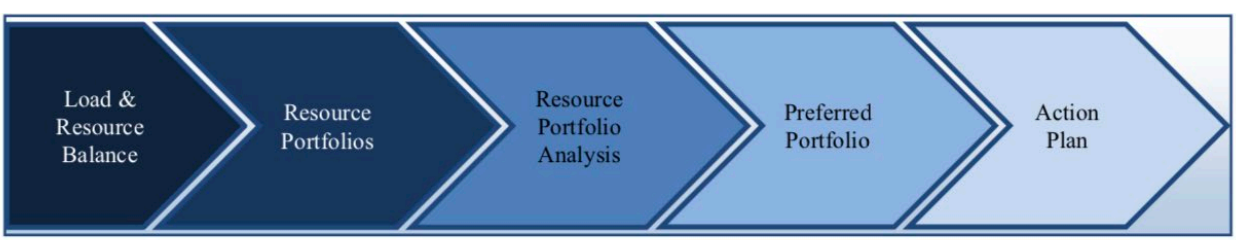

Figure 15. Key Elements of PacifiCorp's IRP Process

4.4.2 Load Forecasting

The load forecast is a key input into the first step of PacifiCorp's IRP process, developing the load and resource balance, which projects whether and when the system will need additional resources.[60] The load and resource balance estimates energy sales and peak demand by state over a 20-year horizon for each of five customer classes: residential, commercial, industrial, irrigation, and street lighting. It first estimates monthly peaks (by state) and then develops hourly forecasts.

For the residential class, PacifiCorp uses a statistically adjusted end-use model to forecast monthly energy sales per customer then multiplies the result by the forecasted number of customers. The commercial class uses a regression analysis that incorporates employment data as the main economic driver and adds weather-related variables. Industrial sales are largely modeled using regression analysis with trend and economic variables, incorporating manufacturing employment as the major economic driver.[61] The industrial customer class develops individual models for a small number of the very largest customers. For irrigation and street lighting, forecasts come directly from historical sales.

After PacifiCorp develops monthly load forecasts, it projects hourly loads using historical load data, historical weather data, and type of day (e.g., weekday, weekend, holiday). It aggregates state forecasts to derive the system load forecast. The load forecast used in PacifiCorp's IRP development excludes forecasted incremental investments in energy efficiency (referred to as Class 2 DSM in the IRP) but does include naturally occurring efficiency or federal and state codes and standard improvements.

4.4.3 Resource potential assessments

PacifiCorp uses its energy efficiency resource potential assessment (referred as a *conservation potential assessment*) to develop the cost and availability (quantity, type, location) of demand-side resources in order to obtain the least cost, least risk, preferred portfolio in their IRP. [62] The conservation potential assessment informs the middle three steps of PacifiCorp's IRP process (see Figure 15)—developing a range of different resource portfolios to meet deficiencies in the load and resource balance; analyzing and comparing the cost, risk, reliability, and emission levels of the different portfolios; and choosing a preferred portfolio based on the least-cost, least-risk resource mix.

PacifiCorp quantifies the technical potential and achievable technical potential of efficiency in its conservation potential assessment (see the text box below for definitions). These values are used to create the efficiency supply curves, which are used in the capacity expansion model to compare demand-side resources with supply-side resources for planning to meet the system's resource needs. PacifiCorp uses a consultant to conduct the potential studies for all the states except Oregon, where the Energy Trust of Oregon conducts the study.

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[60] The capacity position presents the load and resource balance during both winter and summer peak periods.

[61] For Utah, the Industrial Production Index is used instead of manufacturing employment as the major economic driver.

[62] PacifiCorp splits DSM into Class 1 (firm, capacity focused, e.g., direct load control programs), Class 2 (energy efficiency), Class 3 (non-firm, capacity focused, e.g., behavioral programs, rate design), and Class 4 DSM (educational). PacifiCorp assumes Class 4 DSM shows up in Class 1 and Class 2 reductions, and over time in non-program load forecast reductions.

"Technical potential – the theoretical upper limit of energy efficiency potential. It assumes that customers adopt all feasible measures regardless of their cost or customer preferences. At the time of existing equipment failure, customers replace their equipment with the most efficient option available relative to applicable standards. In new construction, customers and developers also choose the most efficient equipment option relative to applicable codes and standards."

"Technical achievable potential – the technical potential is refined by applying customer participation rates that account for market barriers, customer awareness and attitudes, program maturity, and other factors that may affect market penetration of demand-side management measures. The Northwest Power and Conservation Council's Seventh Power Plan provides the customer adoption rates for the technical achievable potential (85 percent of the applicable market over twenty years), also known as the achievability factor. The achievability factor represents potential which can reasonably be acquired by all mechanisms, regardless of how conservation is achieved. Thus, the market applicability assumptions utilized in this study include savings outside of utility programs."

Source: AEG (2019)

The conservation potential study accounts for energy efficiency resources by state, measure, sector, and facility type. The granularity of the data collected produces a very large number of efficiency options, or permutations (i.e., mixes of 324 different measures in each state, sector, and facility type). To make the information more manageable, measures are grouped into bundles based on similar ranges of levelized costs. PacifiCorp develops a supply curve for each levelized cost bundle based on the energy efficiency measures that are in it (Figure 15). The supply curves are used to construct a range of resource mix portfolios where efficiency competes directly against supply-side resources in the IRP, discussed in the next section.[63]

PacifiCorp's conservation potential assessment is unique for several reasons. First, PacifiCorp does not calculate an economic potential in its conservation potential assessment. The economic analysis, or cost-effectiveness testing, occurs in the capacity expansion model, which allows for a direct comparison of the costs and risks of using demand-side and supply-side resources in meeting load.

Second, PacifiCorp creates energy efficiency supply curves from its technical achievable potential that are used in its capacity expansion model. As mentioned above, the first step in creating the supply curves is to determine the levelized cost of energy efficiency measures. The components of the levelized cost vary by jurisdiction. In California, Washington, and Wyoming, the initial capital cost of energy efficiency measures is 100 percent of the incremental costs, and the full cost for retrofit

[63] Cost attributes for DSM include: MW or MWh resource quantities available in each year, persistence of resource savings, hourly shape of the resource and levelized dollars per MWh (PacifiCorp 2019).

measures. In all states, an administrative cost is included that represents the cost to administer efficiency programs in that state.

Third, the technical achievable potential assumes that energy efficiency can be acquired through utility-sponsored programs and alternative acquisition methods (e.g., improved codes and standards or market transformation). In other words, the utility is not arbitrarily limiting the amount of energy efficiency by the amount the utility will pay for efficiency, or how efficiency is acquired.

Finally, PacifiCorp assumes that a percent of the lost-opportunity and retrofit measure technical potential is realized over a 20-year period (referred to as the *ramp* or *adoption factor*). This is a long-held assumption of the Northwest Power and Conservation Council and PacifiCorp.[64] PacifiCorp derives the technical achievable potential for each lost-opportunity measure by multiplying the number of units forecast to turn over in a given year by a ramp rate or adoption factor. For the 2019 IRP, the study determined that, in addition to the natural timing constraints associated with equipment turnover and new construction, there was an 85 percent achievable potential over the 20-year study horizon for lost-opportunity resources.[65] For retrofit measures, the Council and PacifiCorp typically assume that 85 percent of the technical potential can be achieved over the 20-year planning horizon. For both lost-opportunity and retrofit emerging technologies, the Council and PacifiCorp assume market penetration increases gradually over time, so approximately 65 percent of the technical potential is achievable during the 20-year planning period.

4.4.4 Capacity expansion modeling

PacifiCorp uses a System Optimizer model to produce a set of candidate resource portfolios. The model seeks to minimize operating costs for new and existing resources while considering system load balance, reliability, and other constraints. The model performs a dispatch of existing and planned generation. Energy efficiency is available as a resource for the model to select and use in a portfolio. Top performing portfolios (based on cost and risk) are identified, and additional analysis (e.g., assessing market prices risk of relying on new natural gas resources) is performed on these portfolios to identify the preferred portfolio.

Figure 16 lists the cumulative energy efficiency potential by cost bundle. Each cost bundle is $/MWh, and the associated savings are provided in megawatt-hours.

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[65] For non-equipment measures, the study creates annual incremental values to determine the achievable technical potential.

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
<= 10	38,912	98,747	549,917	1,418,505	210,292	394,131
10 - 20	5,902	35,788	109,045	566,451	76,449	111,399
20 - 30	4,600	67,228	344,713	693,917	69,502	68,278
30 – 40	33,081	47,387	611,481	583,173	166,070	251,490
40 – 50	13,351	24,007	527,253	347,710	52,089	233,920
50 - 60	6,383	38,617	260,480	243,779	46,787	167,890
60 – 70	3,769	18,357	200,163	126,915	47,964	74,670
70 – 80	7,788	8,773	168,229	187,482	29,400	30,877
80 – 90	2,953	12,369	70,325	137,044	24,985	14,797
90 – 100	4,346	14,246	11,637	143,151	23,308	41,359
100 – 110	4,338	7,669	56,015	183,773	18,899	85,951
110 – 120	2,303	15,195	39,623	136,567	14,302	20,700
120 – 130	2,189	13,926	15,688	86,346	25,419	13,837
130 – 140	10,391	7,160	115,146	93,739	35,915	6,266
140 – 150	7,600	4,996	62,573	174,762	18,017	19,605
150 - 160	1,930	5,055	137,281	43,708	13,759	9,608
160 – 170	1,947	9,360	33,284	46,478	10,014	6,732
170 – 180	2,458	2,396	72,957	44,581	7,050	17,150
180 – 190	1,723	1,843	15,798	37,927	11,791	10,135
190 – 200	795	1,362	2,294	34,678	20,928	4,693
200 – 250	14,147	32,139	2,924	115,841	56,428	44,598
250 – 300	10,007	8,305	4,795	100,695	17,555	19,324
300 – 400	11,658	13,731	4,220	170,174	31,286	23,599
400 – 500	1,848	4,078	17,134	55,579	11,608	9,894
500 – 750	6,087	10,509	46,965	131,028	24,455	12,672
750 – 1,000	5,567	4,268	42,758	26,471	22,776	16,008
> 1,000	5,423	9,639	21,631	110,459	23,582	29,420

Figure 16. PacifiCorp 20-year Cumulative Energy Efficiency Potential by Cost Bundle

4.4.5 Modeling uncertainty and risk

Once the System Optimizer model has developed candidate portfolios, PacifiCorp compares the portfolios using their Planning and Risk (PaR) model, a production cost simulation model, to select a preferred portfolio. The PaR model estimates the production costs and risk of each candidate resource mix portfolio by running 50 simulated scenarios over the 20-year forecast horizon for each portfolio.[66] PacifiCorp conducts stochastic analysis on inputs (e.g., loads, prices, outages) in their PaR model, and the impacts on the present value revenue requirement[67] and energy not served[68] (PacifiCorp's risk metrics) are measured to develop the ranking for different portfolios.

PacifiCorp accounts for the risk reduction benefits of energy efficiency in two ways. First, it includes energy efficiency resources' impact on load growth when it determines its reserve margin. To account

[66] These scenarios are created by using inputs derived by sampling from distributions of stochastic variables (e.g., wholesale prices, thermal unit outages, natural gas prices, load growth).

[67] The *revenue requirement* is the amount of money a utility needs to collect from ratepayers to cover its costs including a return for investors.

[68] *Energy not served* is a measure of load minus generation and, if positive, indicates that the system cannot meet demand with existing resources.

for uncertainty by ensuring resources are available to cover load demands, PacifiCorp maintains a planning reserve margin. It subtracts its obligations and needed reserves from its existing resources and available front office transactions (i.e., wholesale power sales and purchase contracts) to derive the capacity position needed to maintain its "load and resource balance." The capacity position determines the needed total amount of firm resources that must be available in the preferred portfolio, including reserves.

To calculate its planning reserve requirements, PacifiCorp multiplies its planning reserve margin by its load serving obligation, which is comprised of its total system load less interruptible contracts and new and existing energy efficiency resources. In the 2019 IRP, PacifiCorp's capacity expansion model targeted a 13 percent planning reserve margin that was added to the system's obligation. PacifiCorp considers energy efficiency as a resource that can be used to satisfy its load serving obligation. Therefore, when energy efficiency is subtracted from the utility's load obligation the absolute planning reserve margin that must be met is smaller, reducing both risk and system cost.

The second way PacifiCorp accounts for the risk reduction benefits of energy efficiency is by discounting the cost of acquiring energy efficiency through the application of a stochastic risk reduction credit. The primary reason PacifiCorp includes a risk reduction credit for energy efficiency is because it does not have variable fuel costs that would be affected by market volatility. To establish the stochastic risk reduction credit, PacifiCorp uses its PaR model to produce two production dispatch simulations for each resource portfolio—one on a deterministic basis and the other on a stochastic basis. The stochastic risk reduction credit level is the dollar per megawatt-hour difference between the production costs in the two simulations. The result is that this risk credit is used to reduce the levelized cost of each of the 27 energy efficiency bundles in PacifiCorp's conservation supply curves.[69]

[69] For the 2019 IRP, the risk credit was $4.84/MWh.

5. Observations and Opportunities

We have described how to consider energy efficiency as a potential resource for the future by allowing it to compete with all other electricity system resources. Fundamentally, this means that analysis of the quantity and timing of efficiency procurement occurs within analytical planning and market processes. Public utility commissions, electric utilities, ISOs/RTOs, and efficiency program administrators and implementers that are interested in advancing consideration of efficiency as a resource can:

- Use technical and economic information on energy efficiency that is comparable in scope and detail to what is used in analysis of generation resources.
    - Represent energy-efficient technologies and efficiency programs and requirements with an adequate level of detail and disaggregation.
    - Represent energy efficiency in an integrated way across all components of resource portfolio decision-making.
- Simulate direct competition between efficiency and generation to determine the quantity of efficiency to include in resource portfolios.
    - Determine the level of efficiency as a variable within planning and market processes, directly comparable to supply-side resources.

These approaches may require changes to the methods and tools used to develop resource portfolios, including load forecasting, efficiency resource potential assessments, capacity expansion modeling, and risk and uncertainty analysis. Following are specific actions to implement these approaches.

Load forecasting:

- Develop a range of future load states, not just a single future state.
- Apply sufficient detail for end-use technologies to explicitly capture and isolate the possible efficiency impacts of utility efficiency programs and technical, policy, and regulatory changes that influence energy use.
- Consider using end-use econometric or statistically adjusted end-use load forecasting models, rather than purely statistical/econometric models.
- Use the outputs of load forecasting models as explicit inputs to energy efficiency resource potential assessments and the capacity expansion modeling process.

Efficiency resource potential assessments:

- Use the unit energy consumption, load shapes, the number and type of new and existing buildings, appliances, and equipment from the load forecasting model as inputs to energy efficiency resource potential assessments and capacity expansion modeling.
- Apply historical experience with program design and implementation to estimate achievable energy efficiency potential.
- Assume that utilities are able to acquire energy efficiency resources up to a cost equal to their value to the utility system when calculating achievable potential.

- Use the resource potential assessment to create supply curves quantifying the levels of efficiency that can be obtained at a range of costs, in the form of measures or groups of measures with similar characteristics (e.g., load shapes, levelized cost, and deployment constraints).
- Use supply curves for economic comparison of potential new investments in energy efficiency, other demand-side resources, and generation.

Capacity expansion modeling:

- Use efficiency supply curves as resource options that can be selected for development in a capacity expansion model.
- Determine economic potential (the amount of energy efficiency determined to be cost-effective) of energy efficiency through resource optimization in capacity expansion modeling.
- Modify the capacity expansion modeling acquisition logic to account for energy efficiency's specific development characteristics (e.g., it can be developed in small increments that accumulate to significant capacity over multiple years).

Risk and uncertainty analysis:

- Use direct competition between efficiency and supply-side resources to analyze their relative risk and options for risk mitigation.
- Quantify efficiency's benefits that reduce risk by using a cost credit or by developing expanded stochastic risk assessment capabilities within capacity expansion models.
- Account for energy efficiency resources prior to the calculation of reserve requirements.

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Glossary

Achievable potential is the portion of technical potential that can be expected to be realized over the planning horizon considering the non-financial barriers, (e.g., lack of knowledge, renter versus owner, product availability) that may prevent consumers from adopting energy efficiency measures and practices. It is an estimate of the amount of savings that can be expected to occur within a specified time frame under the assumption that all available mechanisms (e.g., utility programs, codes, standards and market transformation) are deployed.

Avoided costs are the long-term marginal costs a utility would incur in order to supply another unit of energy (kilowatt hours); capacity (kilowatts), including associated distribution and transmission infrastructure; and ancillary services (e.g., spinning and non-spinning reserves). If the utility can reliably operate without producing that unit, it will not incur those costs.

Capacity expansion models simulate the economic dispatch of both the existing and potential future power systems. These computer simulation models are used by utilities and other parties to determine when new resources need to be added to the existing power system to maintain reliability.[70] Such models are generally referred to as *capacity expansion* or *resource planning* models. These models evaluate alternative resource development plans to identify the mix of resources that best meets specific objectives, such as minimizing cost, limiting risk, or reducing emissions. The objective of most of these models is to determine the optimum capacity expansion schedule that maintains system reliability and minimizes the present value of capacity and operating cost.

Econometric models are the most commonly used method of forecasting long-term demand for electricity, as well as for other energy sources such as natural gas. They are also used for forecasting daily or seasonal peak load. These models use statistical analysis (e.g., multiple regression) historical data to estimate the relationship between electricity demand and other independent factors such as population growth, electricity and fuel prices, and weather. Econometric methods are appealing for load forecasting because they are relatively accessible, flexible, require a modest amount of data, are relatively inexpensive, can be easily updated as new projections of driving variables become available, and offer a versatile means for sensitivity and scenario analysis.

Economic potential is most commonly defined as the portion of achievable potential that is determined to be cost-effective based on the economic test (or tests) used by a jurisdiction.[71] Less commonly,

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[70] National-scale examples include the National Energy Modeling System (NEMS), Regional Energy Deployment System (ReEDS), Integrated Planning Model (IPM), Haiku, and MARKAL (MARKet Allocation). Utility or regional scale examples include commercial models such as Aurora, MIDAS, System Optimizer, Strategist, PLEXOS, and public agency models such as the NWPPC Regional Portfolio Model (RPM).

[71] For a more extensive discussion of the cost-effectiveness tests used to screen energy efficiency see the National Standard Practice Manual, National Efficiency Screening Project (NESP) May 2017. Available at: https://nationalefficiencyscreening.org/wp-content/uploads/2017/05/NSPM_May-2017_final.pdf.

economic potential is considered to be that share of technical potential that is determined to be both achievable and cost-effective based on the economic test (or tests) used by a jurisdiction. Whether economic potential is a subset of achievable potential or a subset of technical potential is dependent on the analytical process used to derive its value. The most common analytical process simply applies a "cost-effectiveness limit" to all measures that comprise the achievable potential in a jurisdiction. Such limits can be as simple as a maximum cost per kilowatt-hour, or they can involve a more complex evaluation of a measure's energy savings, its peak demand reduction benefits, and other power system benefits, as well as other non-power system benefits. The second approach involves competing all achievable energy efficiency resource potential directly against supply-side resources to assess whether developing more energy efficiency at varying cost levels increases or decreases the total cost. In this analytical approach *economically achievable* potential is a subset of achievable potential.

Economic optimization logic is the selection criterion used in capacity expansion models, which typically search for resource expansion portfolios that meet system reliability criteria at the lowest cost, using the net present value of utility system revenue requirements as the cost metric. In more sophisticated capacity expansion models, alternative resource portfolios are tested across a wide range of future conditions (e.g., load growth, fuel prices, market prices) to assess their economic risk. The economic optimization logic in these models typically compares the forecast value of electricity (both energy and capacity) with the estimated cost of a new resource. Generation capacity expansion models typically do not include consideration of transmission and/or distribution system or non-wires alternatives in their economic optimization or reliability assessment process.

Energy efficiency supply curves represent the quantity of savings across a range of acquisition costs in each of the years, including the resource planning period. Supply curves can represent technical, economic, or achievable potential. In their simplest form energy efficiency supply curves represent the amount of savings that could be achieved at a specific cost during a specific period (technical potential does not include a cost assessment). However, when the economic potential of energy efficiency is determined through the use of capacity expansion models, multiple supply curves are generally required. To accurately represent the range of energy efficiency resources available, measures with similar characteristics, such as common load shapes and availability through time, are typically represented by different supply curves.

End-use econometric forecasting models explain electrical demand as a function of the number, characteristics, and usage of electrical equipment and prices. This forecasting approach requires information such as the number and type of electric appliances in the home, number and size of households, size and type of commercial and industrial users, et cetera. These models combine the ability to reflect relationships between economic factors (income, employment, energy prices) and energy demand, while also providing a detailed explanation of how changes in technology or structural changes in the economy, such as new loads from data centers and EVs and codes and standards, as well as consumer behavior, affect electricity use.

Energy-related time-varying value is the energy-related time-varying value that comprises the following values: avoided energy, risk reduction, carbon dioxide emissions, avoided renewable portfolio standard compliance, and wholesale market price suppression effects.

Levelized cost is the present value of a resource's cost (including capital, financing, and operating costs) converted into a stream of equal annual payments. This stream of payments can be converted to a unit cost of energy by dividing them by the number of kilowatt-hours produced or saved by the resource in associated years. By levelizing costs, resources with different lifetimes and generating capabilities can be compared.

Lost-opportunity energy efficiency resources are those measures that can only be captured during a specific window of opportunity, such as when a new home is being constructed or a new appliance is purchased. Failure to influence the efficiency of energy use at this time means the opportunity to improve efficiency is lost until this event occurs again, which for some measures like building construction may be decades.

Naturally occurring efficiency is the amount of savings that can be expected to result from the adoption of energy-efficient measures by consumers in response to normal market dynamics such as product features and electricity price.

Retrofit energy efficiency resources represent savings that could be achieved at any time through immediate action that reduces energy consumption.

Savings load shape is the difference between the hourly use of electricity in a baseline condition and the hourly use post-installation of the energy efficiency measure (e.g., the difference between the hourly consumption of an electric resistance water heater and a heat pump water heater, or the difference between the hourly lighting use in a commercial building pre- and post-installation of daylighting controls or occupancy sensors) over the course of one year.

Statistically adjusted engineering (SAE) forecasting methods, which are a subset of end-use econometric models, combine the strengths of end-use and general econometric methods to enhance a model's explanatory power. The basic concept of SAE models is to combine engineering and statistical methods by entering simulated engineering loads for each end use as explanatory variables in statistical models and estimating adjustment factors for the engineering loads.

Stochastic modeling or methods incorporate uncertainty of the inputs, which usually leads to uncertainty of outcomes. Stochastic methods frequently use inputs from probability distributions that mimic or simulate the real world. Stochastic models are most suited for use in a situation when multiple independent variables have uncertainty. For example, future wholesale electricity market prices (the dependent variable) is a function of multiple independent variables, including natural gas prices, the pace of load growth, the cost and availability of both supply-side and demand-side resources, and other factors, all of which are uncertain. Stochastic modeling or methods are frequently used in risk assessment to determine the probability of "bad outcomes," as well as the range.

Supply curve is a standard economic representation of the cost and availability of a product or, in this case, electricity system resources. It represents the amount of the resource available at a range of costs.

Technical potential is an estimate of energy savings based on the assumption that all existing equipment or measures will be replaced with the most efficient equipment or measure that is both available and technically feasible over a defined time horizon, without regard to cost or market acceptance. It assumes complete adoption of all technically applicable potential energy efficiency measures regardless of cost, funding, or consumer acceptability. It is only constrained by physical limits (e.g., the maximum amount of insulation that can be installed in an attic, the most efficient commercially available refrigerator).

Total resource net levelized cost is the difference between total levelized costs and total levelized benefits of a resource. Total levelized costs include all quantifiable and monetizable cost of a resource that are forecast to be incurred over its expected service life, such as its capital, operation, maintenance, fuel, and environmental compliance costs. For energy efficiency and demand response, this includes the cost of program administration and evaluation. Total levelized benefits are all quantifiable and monetizable electricity system benefits directly attributable to a resource, including deferred transmission and distribution expansion costs on the electric system if, and to the extent, measures reduce coincident peak load. In addition, those non-energy system benefits included in a jurisdiction's cost-effectiveness criteria—such as the reduction in the consumption of other-fuels, lower operations and maintenance expenses, water savings, and environmental benefits—may be included. Estimating total resource net levelized cost requires comparing all the costs of a measure with all of its benefits, regardless of who pays those costs or who receives the benefits. For some measures, total resource net levelized cost can be less than zero because electric plus non-electric benefits exceed the cost.

Unit energy consumption (UEC) describes the amount of energy consumed annually by a specific technology in buildings that have the technology. The UECs are expressed in kilowatt-hours per household for the residential sector and energy use intensity (EUI) is expressed in kilowatt-hours per square foot or employees for the commercial and industrial sectors (AEG 2019).

APPENDIX A. Resource Potential Assessments

Reasonably accurate and reliable information about the amount, savings load shape, availability, and cost of energy efficiency resources are important inputs for electricity resource planning. This information is typically obtained by conducting energy efficiency (or conservation) potential studies. Potential studies can serve two important objectives: (1) provide data on the amount, timing, and cost of available energy efficiency, and (2) provide critical input for the design of energy efficiency programs. Potential studies are often performed at the end-use and customer-sector levels, and the results can be aggregated to different geographic levels such as a utility, state, or region.

Energy efficiency potential analysis typically begins by identifying end uses of electricity (e.g., lighting, heating, and cooling) where energy efficiency measures exist, and the savings and potential number of installations associated with the measures. This produces the ***technical potential,*** an estimate of energy savings based on the assumption that all existing equipment or measures will be replaced with the most efficient equipment or measure that is both available and technically feasible over a defined time horizon, without regard to cost or market acceptance.

Economic potential is determined using one of two analytical processes. The most common applies a cost-effectiveness limit to all measures that comprise the technical potential in a jurisdiction. Such limits can be as simple as a maximum cost per kilowatt-hour or involve a more complex evaluation of a measure's energy savings, peak demand reduction benefits, or other power and non-power system benefits. The second approach that is consistent with the principles discussed in Chapter 3 competes energy efficiency resources directly against supply-side resources to assess whether developing more energy efficiency at varying cost levels increases or decreases the total electricity system cost.

Achievable potential is the portion of technical potential that can be realized after considering *non-financial barriers* (e.g., lack of knowledge, renter versus owner, product availability) that may prevent consumers from adopting energy efficiency measures and practices. Depending on the jurisdiction, it may be an estimate of the amount of savings that can be expected to occur within a specified time frame under the assumption that all available mechanisms (e.g., utility programs, codes, standards and market transformation) are deployed, or it may only consider the quantity of savings that can occur from utility customer-funded efficiency programs.

The relationship among the various types of energy efficiency potential (Figure A - 1) varies by jurisdiction and the objectives of the potential study. When energy efficiency is treated as a resource, the determination of economic potential occurs following the assessment of achievable potential. In contrast, in the more typical process, technical potential is first reduced by the subjecting efficiency measures to a predetermined cost-effectiveness screening criteria. The resulting economic potential is then reduced to a level deemed achievable.

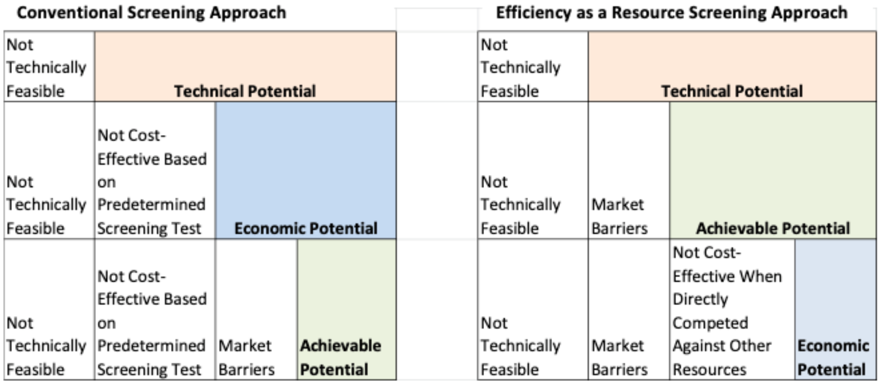

Figure A - 1. Pathways to Identifying Energy Efficiency Potential

Accounting for "Naturally Occurring" Efficiency in Potential Assessments

Naturally occurring efficiency is the amount of savings that can be expected to result from the adoption of energy efficient measures by consumers in response to normal market dynamics such as product features and electricity price. In theory, all naturally occurring efficiency potential should be included in an econometric load forecast because these forecast models are designed to reflect historic trends in consumer behavior and technology adoption. However, simply looking at past trends does not incorporate efficiency gains from more stringent building codes or higher equipment energy efficiency standards that have been finalized and will take effect during the planning horizon. These should be incorporated in the business-as-usual forecast and serve as the baseline from which additional efficiency potential is determined. As discussed in the body of this report, end-use econometric or SAE load forecasting models enable direct comparisons between forecasted consumption and energy potential at the end-use level.

Estimating Technical Potential

Energy efficiency measures can reduce energy and peak demand by reducing the wattage needed to accomplish a given task (e.g., use of light-emitting diode [LED] lamps that require 12 watts to produce the same lumen output as 75 watt incandescent lamps); reducing the hours of operation (e.g., use of occupancy sensors to switch off lights in unoccupied spaces); or a combination of both wattage reduction and reduced hours of operation (e.g., use of daylighting controls to reduce wattage and to switch off lighting when natural lighting is adequate).

Broadly speaking, assessing technical potential entails creating an estimate of savings that could be achieved by any of these three approaches, assuming that every physically feasible end-use efficiency measure will be installed over some period of time, usually 10 to 20 years. Total technical potential generally falls into two resource categories:

- *Retrofit* or instantaneous technical potential represents savings that could be achieved *at any time* through immediate energy efficiency actions that affect energy-use behavior. For example, the lighting system in an existing building can be retrofitted at any time.
- *Lost-opportunity* potential savings can only be captured during a specific window of opportunity, such as when a new home is being constructed or a new appliance is purchased. Failure to influence the efficiency of energy use during this time means that the opportunity to improve efficiency is generally lost for the life of the measure. The time period covered by the potential assessment is critical because it constrains the number of lost-opportunity energy efficiency measures to those that occur within that time frame.

Development of the technical potential savings can be derived from standard engineering calculations or energy efficiency program evaluations, or based on deemed savings from technical reference manuals. When treating energy efficiency as a resource, these assessments must be quite granular, identifying levelized cost and savings by measure, load profile, building type, sector, and vintage for each year of the planning period.

The most widely used method for estimating technical potential, commonly referred to as a *bottom-up approach,* starts with estimated savings for each individual efficiency measure, then multiplying those savings by the maximum market saturation of the measure.[72] The main advantage of this approach is that through thorough characterization of specific energy efficiency measures and practices, it provides detailed information that informs energy efficiency planning and program design. The bottom-up approach requires users to compile information on a large, comprehensive number of energy efficiency measures and practices, their costs, potential savings impacts, and how they interact with energy systems and each other. Computation of technical potential savings using this method is mathematically straightforward: technical potential = savings per unit × the number of technically feasible units.

When assessing technical potential, it is important to account for the impact of codes and standards, as well as interactions between efficiency measures. Improvements in energy codes and standards affect the baseline assumptions regarding end-use energy intensity and therefore affect energy efficiency measure savings. To avoid overstating or double counting the savings from codes and standards, the analysis of technical potential must factor in the anticipated impact of approved codes and standards that take effect in the future.

[72] In addition, there are federal and private models that simultaneously assess technical and economic potential, but they generally lack sufficient detail to inform subsequent program design. One example is the U.S. Department of Energy's National Energy Modeling System (NEMS). In this end-use econometric model, potential efficiency improvements are modeled through the use of "technology trade-off curves." These curves attempt to represent the efficiency level consumers would select at varying electricity or natural gas prices. That is, the potential to improve efficiency is treated in terms of a consumer's economic decisions. Energy-efficiency potential in these models is determined by first generating a baseline forecast and comparing its results to a second forecast that incorporates the impacts of a broad range of energy efficiency measures and energy use behaviors that can be driven by either prices or policies (e.g., changes in equipment standards). Similar forecasting models and methods (e.g., Energy 2020 and EPRI's REAP and COMMEND models) have been used to develop estimates of energy efficiency potential at the national, regional, state, and utility levels.

As discussed in this report, when considering efficiency as a resource, the savings from known codes and standards should be embedded in the load forecast. Naturally occurring savings such as efficiency improvements resulting from appliance and equipment stock turnover (i.e., replacements) should also be included in the load forecast. To avoid double counting these savings, the efficiency level used as the basis for determining remaining potential should use the levels required by codes and standards, unless current practice efficiency levels are higher. The "better of codes, standards, or practice" rule ensures that the forecast loads and energy efficiency potential assessment use internally consistent assumptions.

The calculation of technical potential may also account for three types of interactions that affect the level of electricity savings. First are the interactions between equipment and facility improvements. For example, savings from the installation measures such as improvements to the building shell or building heating, ventilation, and air conditioning (HVAC) equipment may be affected by the installation of high-efficiency electric lighting.

Second, two or more energy efficiency measures may be applicable for the same end use. For example, a SEER 15 or SEER 16 air conditioner could be installed in a home, thus they have overlapping potential. To avoid double counting the technical savings potential at the end-use level, these interactions can be accounted for by either assigning each competing measure a "share" of the applicable end use or by assessing their incremental impacts. Continuing with the air conditioning example, the incremental savings from a baseline efficiency air conditioner to a SEER 15 can be multiplied by the number of air conditioners available to upgrade. The additional savings (and cost) for the SEER 16 air conditioner might then be calculated using the SEER 15 system as the baseline. Alternatively, some fraction of air conditioners available to upgrade could be assigned to the SEER 15 and the rest assigned to the SEER 16.

Finally, certain energy efficiency measures affect an end use indirectly and can result in overstating or understating savings potential. For example, installing more efficient lighting may increase heating loads while lowering cooling loads, and installing high-efficiency clothes washers can reduce the time required for drying clothes.

All of these interactive effects are typically dealt with by systematically stacking their effects so that only incremental savings are used to estimate technical potential. The order in which certain energy efficiency measures are entered into the calculation of technical potential affects a measure's savings. Generally, there are two options for stacking an efficiency measure's effects. An analyst can make reasonable assumptions about the order in which the various measures might be installed; for example, according to their relative cost-effectiveness. The second option is to establish a rolling, declining baseline electricity use for each affected end use and apply it iteratively to measures, based on their order in the stack.

Estimating Economic Potential

The first step in estimating economic potential is to establish the cost-benefit analysis inputs. Cost-benefit analysis is intended to determine whether the benefits of an investment outweigh its costs.

Cost-benefit analysis (e.g., total resource cost test, resource value test) is used to understand energy efficiency cost-effectiveness, and is typically established through local regulatory or legislative mandates. Consistent with the principles discussed in Chapter 3, cost-benefit analysis for energy efficiency should be comparable to that used for other resources.

As described previously, there are two general approaches used to conduct cost-benefit analysis on technical potential. The difference between the two approaches is how the avoided costs are determined. In the first approach, analysts use predetermined avoided costs as an input in energy efficiency cost-benefit analysis. This is the most common method used today. In this approach, the avoided cost of additional electricity resources serves as the fundamental basis of comparison for determining the quantity of efficiency that is economic. In the second approach, energy efficiency competes directly with other resources in the capacity expansion modeling process. This approach allows the model to determine the impact of energy efficiency on system load growth and load shape. Thus, it impacts the type, amount, and timing of conventional resource development.

Estimating Achievable Potential

The objective of an achievable potential assessment is to determine the level of energy efficiency that can be reliably developed through programs, policies, and regulations that are specifically designed to overcome barriers that limit adoption of energy efficiency measures. Estimating achievable potential is subjective because it involves making assumptions about consumer behavior and decision-making processes.

APPENDIX B. Risk and Uncertainty Analysis

Risk is the potential for gaining or losing something of value. A paper by Binz et al. (2012), intended to help utility regulators incorporate risk into their decisions, summarized what risk is and why it matters:

> Risk arises when there is potential harm from an adverse event that can occur with some degree of probability. Put another way, risk is “the expected value of a potential loss.” Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both. Risks for electric system resources have both time-related and cost-related aspects. Cost risks reflect the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations. Time risks reflect the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which benefits consumers.

In some cases, scenario analysis and sensitivity studies use deterministic models, where the output of the model is fully determined by the parameter values and the assumed initial conditions. That is, in these models the solution to the problem of the type, amount, and timing of resource development can only have one right answer. However, by changing the input assumed for one parameter, the sensitivity of the selected portfolio to that parameter can be tested.

In their simplest form, these deterministic approaches to risk analysis test energy efficiency’s cost-effectiveness across a range of potential avoided resource costs that might occur under alternative input assumptions for supply-side resources. For example, capacity expansion models are used to test alternative scenarios to determine the optimum level of energy efficiency to acquire under across a range of forecast natural gas prices. The results of these scenarios are then compared to one another to determine how sensitive the amount of energy efficiency development is to different natural gas price assumptions and the economic risk posed by developing more or less energy efficiency. This information, along with professional judgement, is then used to adjust the cost-effectiveness limit for the energy (MWh) and capacity (MW) savings of energy efficiency resources, considering the uncertainty of future fuel prices.

In its simplest form this approach combines distributions of the intrinsic risk factor (e.g., cost, performance, lead time) of each resource in capacity expansion models to assess the cumulative or combined risk of bad outcomes.[73] In other words, the overall probability that cost will be higher, performance poorer, and lead time longer than expected, or on average. Values from the resultant distributions are then used to compute both the expected value (i.e., average) cost and benefits of

[73] These distributions recognize that risk is a measure of the expected severity of bad outcomes. That is, in risk assessments, the tails of the probability distributions, especially the “bad” tail, assume greater significance. Therefore, greater emphasis is focused on ensuring that the tails of the distributions for cost and performance of resources, including energy efficiency, are representative not just the means, medians and/or standard deviations of these distributions. While means, medians, and/or standard deviations are useful metrics, they do not measure risk. Rather, in this context they are measures of central tendency/predictability, but not risk.

energy efficiency (and supply-side resources). However, more important from a risk perspective, results are used to assess the probability or risk that a particular measure, program, and/or overall portfolio of energy efficiency measures (or supply-side resources) will have cost that make them uneconomic. While stochastic or probability analysis is an improvement on deterministic scenario analysis and sensitive studies, this practice does not address how the intrinsic risk of each resource interacts with the inherent uncertainty of future conditions.

To capture the full risk reduction value of energy efficiency resources, a more complex practice to stochastic analysis is used; one that considers not only the *intrinsic* risk of resources but their interaction with each other and with *uncertainty* about the future. In this approach, resources are subjected to a wide range of future conditions that do not have well-defined distributions. Rather than using fixed variables about the future, as in deterministic modeling, stochastic capacity expansion models incorporate random variations to simulate future conditions against which alternative resource portfolios can be tested. Since there are multiple factors that influence the type, amount, and timing of resource development, Monte Carlo simulation is used to test each resource portfolio across hundreds or even thousands of future conditions. This process allows users to identify which outcomes are most likely (e.g., the *expected* net present value of utility system cost and *expected* amount of energy efficiency development), as well as the range of outcomes (e.g., the 90th decile net present value utility system cost) that can be expected. This practice best quantifies and monetizes the risk mitigation benefits of energy efficiency resource (and supply-side resources) because it models the *intrinsic risk* factor of each resource and those factors that make a resource risky due to the *inherent uncertainty* regarding future conditions.

In the most sophisticated of these capacity expansion modeling processes, portfolio optimization does not assume or rely on "perfect foresight." The increased level of sophistication is valuable because perfect foresight capacity expansion models systematically understate energy efficiency's risk reduction value because these models never make "mistakes." Since energy efficiency's risk reduction value stems from short lead times, scalable (modular) annual development, lack of fuel price, and market price risk it has more limited exposure to uncertainty about these factors. Perfect foresight models "know the future" and therefore eliminate these risks.

These more sophisticated capacity expansion models attempt to mimic how decisions are actually made and, because it is impossible to predict the future, purposefully evaluate those decisions against future conditions that differ from those assumed when the decision was made. For example, in these models, "actual" load growth can differ from the load forecast used to determine resource expansion schedules. As a result, the timing of a resource addition which was forecast to be "just in time" could be too early or too late. Similarly, the model may select the level of energy efficiency development based on a forecast of high natural gas prices, but in the "actual" future simulated by the model, natural gas prices could be much lower. This practice more closely represents reality, which requires decision-making under uncertainty.[74]

Monte Carlo Simulation

Risk analysis modeling is frequently conducted using *Monte Carlo* simulation (also known as the *Monte Carlo Method*), which can be described in layman's terms as scenario analysis on steroids.

Monte Carlo simulation is a computerized mathematical technique that allows people to account for risk in quantitative analysis and decision-making. Monte Carlo simulation allows analysts to see the possible outcomes of decisions and assess the impact of risk, allowing for better decision-making under uncertainty. Monte Carlo simulation performs risk analysis by building models of possible results by substituting a range of values—a probability distribution—for any factor that has inherent uncertainty. It then calculates results over and over, each time using a different set of random values drawn from the probability functions. Depending upon the number of uncertainties and the ranges specified for them, a Monte Carlo simulation could involve thousands or tens of thousands of recalculations before it is complete. When completed, Monte Carlo simulation produces distributions of possible outcome values.

Less Risk: Energy efficiency's value under low market prices

Assume a combined-cycle combustion turbine (CCCT) has a capital cost of $15/MWh and a dispatch cost of $35/MWh. Therefore, it cannot provide a positive net benefit (i.e., recover its full cost) until its market prices exceed $50/MWh. Let us also assume that this CCCT is setting the market price, which would therefore be $50/MWh. If this market price serves as the cost-effectiveness limit of a supply curve for energy efficiency that is linear between zero and $50/MWh, the average cost of energy efficiency would be $25/MWh. If market prices drop to between $16/MWh and $25/MWh, both the CCCT and the energy efficiency resources would lose money, but the turbine would lose more money. Between $25/MWh and $50/MWh, the energy efficiency resources are recovering their full cost (i.e., paying for itself), but the combustion turbine is not. Therefore, at market prices above $16/MWh, energy efficiency provides greater value than the CCCT.

This example demonstrates why acquiring energy efficiency is less risky than dispatchable generating resources, such as simple or combined-cycle combustion turbines, when low market prices are likely in the future. In this example, energy efficiency is a lower risk solution unless market prices are extremely low, below $16/MWh. However, even under that circumstance, lower purchase power costs from the market for loads not met by energy efficiency provide the utility a hedge against the above-market cost of energy efficiency.

[74] For example, see the case studies in Chapter 4 for the Northwest Power and Conservation Council (NWPPC) and PacifiCorp. The NWPPC determined the level of energy efficiency that is cost-effective by modeling 800 alternative futures, each with a different fuel price, market price, load growth path, and carbon cost for its Seventh Northwest Power Plan. (Available at: https://www.nwcouncil.org/reports/seventh-power-plan). Using similarly techniques, PacifiCorp in its 2019 Integrated Resource Plan modeling process estimated a risk reduction benefit for energy efficiency (PacifiCorp 2019).