2020 BIENNIAL ENERGY REPORT

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Executive Summary

In 2017, the Oregon Department of Energy, recognizing that the energy world has changed dramatically since the 1970s, introduced House Bill 2343 to the Legislature. The bill charged the department with developing a new Biennial Energy Report to inform local, state, regional, and federal energy policy development and energy planning and investments. The report – based on analysis of data and information collected and compiled by the Oregon Department of Energy – provides a comprehensive review of energy resources, policies, trends, and forecasts, and what they mean for Oregon.

What You Can Expect to See in the 2020 Biennial Energy Report

The 2020 report takes a different approach than the inaugural 2018 Biennial Energy Report, which provided deep policy dives on a handful of important energy topics — including climate change, renewable energy, transportation, energy resilience, energy efficiency, and consumer protection. This 2020 report follows recommendations by energy stakeholders to provide shorter briefs on a wider array of energy topics — from energy in the agriculture sector to what's next for alternative fuels to the effects of the COVID-19 pandemic on energy, and more.

Many sections show that Oregon is on a path toward transitioning to a cleaner, low carbon future. Data and examples included in the report illustrate sustained investments in energy efficiency, affordability, renewable energy, and resource conservation. These efforts have positioned Oregon to successfully tackle today's energy challenges, which are driven by growing adoption from consumers for cleaner energy, economic innovation, and emerging technologies.

The report begins by looking at **Energy by the Numbers**—detailed information on Oregon's overall and sector-based energy use, energy production and generation, energy expenditures, and the strategies Oregon has employed to meet growing energy needs. New in 2020 is an energy flow diagram, illustrating energy production and imports to eventual end-use.

Next up is a **Timeline of Energy History in Oregon,** starting with the Missoula Floods that formed our state and ending with 2020's latest events — including the closure of Oregon's only coal power plant and new actions to tackle climate change.

The **Energy 101** section aims to help readers understand the first part of the energy story: how energy is produced, used, and transformed. Information is meant to provide a foundation for those new to energy and those who are already steeped in the sector.

The **Resource and Technology Reviews** section highlights 23 energy resources and technologies — they cover the spectrum of tradition to innovative, from renewable resources to emerging technologies like microgrids and power-to-gas. The topics covered are prevalent in Oregon or of interest to ODOE's various stakeholders. Many of the technologies offer opportunities to invest in Oregon's economy by creating energy-related jobs, including those focused on restoring our energy systems when disruptions occur.

The final section includes more detailed **Policy Briefs** that cover decarbonization, the transition of the electric grid, innovation in the natural gas system, cleaner transportation options, and the built environment and Oregon's communities. The primary purpose of the report — and these policy briefs — is to inform energy policy development, energy planning and energy investments, and to identify opportunities to further Oregon's energy policies.

The Biennial Energy Report wraps up with a new summary of the process used to develop the report and **closing thoughts** on what's next. ODOE will kick off discussions in 2021 and reach out to hear new voices on recommendations for energy policy in Oregon over the next two years — and beyond.

The Biennial Energy Report may be found in its entirety at

https://energyinfo.oregon.gov/ber

or

www.oregon.gov/energy/Data-and-Reports/Pages/Reports-to-the-Legislature.aspx

The Department of Energy welcomes your comments and questions. Please contact our agency at askenergy@oregon.gov.

The primary purpose of the Biennial Energy Report is to inform local, state, regional, and federal energy policy development, energy planning, and energy investments, and to identify opportunities to further the state's energy policies.

In service of ODOE's role as the central repository within state government for the collection of data on energy resources, the report collects and analyzes critical data and information to provide a comprehensive and state-wide view of the energy sector. The term "energy" includes many intersecting systems that generate and distribute electricity to end-users, and that store and distribute fuels for home-heating, industrial processes, and transportation. It also includes the critical infrastructure, facilities, planning, and energy management that support these systems. A key consideration in analyzing the energy system is effects that it has on public health, the environment, and communities across the state. It is long past time to examine and address where our energy choices do not provide equitable distribution of benefits and burdens to Oregonians.

This section of the report provides insights on emerging energy trends, opportunities, and barriers in the energy sector. ODOE began the development of this portion of the report by listening – and then identifying the critical energy questions and issues that we heard from stakeholders, policy makers, and the public. ODOE applied a data and equity lens in determining topics for this policy briefs section of the report – are these questions being asked by people or entities that have historically not been at the table? Do we have the data and information to help answer these questions? The topics covered in the following pages also seek to answer some of the questions frequently heard by multiple people or entities; many energy stakeholders confirmed to ODOE that they were hearing similar questions and about similar information gaps: *How is the state addressing climate change and what can be done to improve the resilience of the energy sector? How are Oregon's farmers and ranchers reducing energy use and greenhouse gas emissions? What types of opportunities exist to reduce fuel use and fuel costs for the freight sector? What are the trends and potential for offshore wind and power-to-gas in Oregon? How can the state address equitable access to renewable energy for all Oregonians? How has COVID-19 affected the energy sector?*

These policy briefs can be read as standalone documents, and there are cues in each discussion to point the reader to information and data found in other parts of the report that can provide additional background and insight. This collection of policy briefs is not comprehensive – it is a snapshot of analysis for key questions in the lead up to the publication of this report. Staff at ODOE are engaged in research and analysis on other topics that are not covered in this section, and energy expertise exists in other agencies and outside state government as well. As ODOE wraps up production on the 2020 Biennial Energy Report we continue to listen, and new topics are already beginning to emerge as potential questions to address for the 2022 Biennial Energy Report.

Policy Brief: Evaluating the Resource Adequacy of the Power System

Background

The electric power system is unique, relative to other industry sectors, in that it has little to no capability to store electricity as an end-use fuel. As a result, the electric generation and transmission system must be built to satisfy the largest hourly requirements for electricity—called peak demands—even though consumers use less (oftentimes significantly less) during most hours of the year. This results in an electric generation and delivery system that is, by design, underutilized much of the time, especially when compared to the liquid fuels and natural gas sectors.[1] To evaluate the adequacy of the power system, utilities and grid planners must forecast customer demand for electricity and compare that to the ability of existing resources to meet that demand in real-time. If the capabilities of existing resources might fall short, then new capacity resources will need to be developed – a process that can require several years (or more) depending on the types of resources.

> **Suggested reading:**
>
> For more background on Resource Adequacy and why it's important for maintaining the long-term reliability of the power system, see the Energy 101 on Resource Adequacy.

> **Resource Adequacy** (or RA) is the term that grid planners and utilities use to refer to the evaluation of whether adequate generating capacity will be available to meet forecasted demand over the next several years (typically from one to five years).[i]

Resource Adequacy can be evaluated for individual load-serving entities, like a utility, or for local areas within their system. It can also be evaluated for balancing authority areas, for states, or for entire regions. In any case, the following are several key technical questions that must be considered as part of an adequacy evaluation:

Table 1: Resource Adequacy Evaluation: Key Technical Questions

Demand: How much power will customers require in the future?	○ **Energy efficiency**: How much incremental energy efficiency savings will accrue? ○ **Population**: Is the population expected to increase or decline? And by how much? ○ **Economic growth**: Will the economy grow at its current rate? Will it accelerate? Will it slow down? ○ **Electrification**: To what extent are customers expected to adopt electric vehicles or switch from gas to electric furnaces?

[i] Note that **Resource Adequacy** in this context focuses on long-term resource acquisition strategies to ensure adequate future power supplies, whereas the similarly-named **Resource Sufficiency Tests** (applied by the Western EIM) focus on the short-term management of existing resources and must be met hourly in order to fully participate in the EIM's real-time markets. (see Wholesale Electricity Markets Policy Brief for more information).

	○ **Large loads**: What is the potential for large industrial customers to enter or leave the utility's service area? ○ **Extreme weather**: What is the likelihood of severe cold or hot weather that could set a new annual peak demand? ○ **Climate change**: How much is climate change expected to affect historic weather patterns, changing the likelihood of severe weather? ○ **Demand response**: To what extent can customers be incentivized to reduce demand during peak hours?
Supply: How much power can generation resources deliver in the future?	○ **Energy constraints**: Do any of the utility's supply-side resources have constraints on energy availability? (e.g., variability in renewable energy availability or potential limitations on natural gas delivery to power plants) ○ **Ramp rates:** What are the ramping capabilities of the utility's capacity resources to quickly increase or decrease output to respond to changes in net load? ○ **Retirements**: Are there any existing resources scheduled for retirement? ○ **Resources under development**: Do any utilities in the region have generation resources currently under development? Should expected future output from those resources be incorporated into the analysis? ○ **Proposed resources**: Are any utilities in the region currently proposing or planning to develop new generation resources? Should potential future output from those resources be incorporated into the analysis? ○ **In-region market resources**: Historically, how many in-region resources have been available on the market during the utility's peak demand hours? Is that market availability expected to change materially? Will those market resources become exceedingly expensive under certain conditions (e.g., heatwave across the entire western U.S.)? ○ **Out-of-region imports**: How much power from out-of-region can be expected to be available for import to meet demand? ○ **Transmission constraints**: Do in-region or out-of-region constraints on the transmission system impede the delivery of power to load centers?

- **Climate change**: To what extent is climate change expected to affect these supply-side considerations, such as the availability of hydropower due to changing precipitation patterns or market resources due to changing loads across the west (e.g., higher demand for AC during hotter summers)?

In many cases, these technical questions cannot be answered with certainty, and instead a probability must be attributed to any one of a range of possible outcomes. The answer to any one of these questions has the potential to significantly impact the overall evaluation of RA, either in terms of how much demand is expected or how much supply is available. Ultimately, these are *technical questions* that must be evaluated by utilities and grid planners. Before an evaluation of RA can address these technical questions, three key *policy questions* must first be answered to define the parameters within which that technical evaluation will occur:

Policy Question #1 – Perspective: From what perspective should we evaluate these technical questions? From the perspective of an individual utility or load-serving entity (e.g., Portland General Electric)? At the statewide level (e.g., Oregon)? The entire region (e.g., Pacific Northwest)? Or even a larger area (e.g., the entire western United States)?

Policy Question #2 – Risk: Given the uncertainty surrounding future conditions, it is cost prohibitive to build adequate power resources that can meet customer demand 100 percent of the time no matter the circumstances. Thus, this policy decision comes down to answering a basic question: how much risk is acceptable when it comes to a utility, state, or region having inadequate capacity available to meet forecasted future demand for electricity?

Policy Question #3 – Time Period: Many jurisdictions evaluate the adequacy of capacity to meet forecasted future peak demands for electricity on an annual basis, irrespective of when those peaks occur within the year. Could alternative methods evaluate capacity adequacy on a monthly or seasonal basis, with potentially significant impacts on which capacity solutions are identified?

There is no right or wrong answer to these policy questions and multiple entities—individual utilities, a collection of utilities voluntarily pooling together, a state regulator like the PUC, a regional independent system operator, or even a state legislature—might have different perspectives on what the answers should be. Thus, depending on each entity's perspective, future "reliable" power systems could be made up of different resource portfolios with vastly varied costs. These policy questions are examined in more detail below.

This section is intended to serve as a guide for a reader trying to better understand the key policy questions that underlie existing technical evaluations of RA and that must be addressed before engaging in any new evaluation of the long-term reliability of the power system.

What it Means for Oregon

Oregonians have long enjoyed a very reliable, relatively low-cost (and low carbon emitting) power system compared to many other parts of the country. As described in RA 101, the Northwest Power and Conservation Council (NWPCC) annually develops a long-term regional assessment of RA that evaluates the adequacy of the region's power supply five years in the future.[2] The goal of the NWPCC's RA assessment is to "establish a resource adequacy framework for the Pacific Northwest to provide a clear, consistent, and unambiguous means of answering the question of whether the region has adequate deliverable resources to meet its load reliably and to develop an effective implementation framework."[3] Individual utilities in Oregon often use the NWPCC analysis as an input into their own evaluation of RA for their systems, because they (and their regulators) are responsible for ensuring that they have adequate capacity to meet the demand of their customers.

Utility Resource Planning in Oregon

All electric utilities engage in some version of electricity supply planning to ensure the continued delivery of safe, reliable, and affordable power to customers across Oregon. Every several years the state's IOUs, for example, file Integrated Resource Plans (IRPs) with the PUC. These plans are developed with significant stakeholder input and focus on resource actions over an approximately 4-to-5-year time horizon. According to the PUC, the IRP is intended to present the utility's current plan to meet the future energy and capacity needs of its customers through a "least cost, least risk" combination of resources, inclusive of supply- and demand-side measures.[4] The PUC does not pre-approve proposed actions in an IRP but instead will "acknowledge" a proposed action, which serves as a factor in the PUC's later review of the prudency of individual investments.[5]

Many of the state's COUs also engage in a similar type of electricity supply planning process, subject to the review of their governing boards. A significant number of Oregon's COUs ("full requirements" customers) rely entirely on BPA for all of their power needs.[6]

It is through these types of integrated evaluations of future resources and demand that utilities in Oregon identify a need for additional capacity resources to maintain an adequate power supply. For more on the latest regarding recently filed and under development IRPs from the state's largest electric utilities, see the following:

Portland General Electric: Integrated Resource Planning

PacifiCorp: Integrated Resource Plan

EWEB: Electricity Supply Planning

Meanwhile, the Northwest Power Pool is currently developing a program that is expected to formalize a short-term regional assessment of RA for the northwest that would be contractually binding on individual participating utilities and load-serving entities.[7] Those entities would voluntarily join the program, but then would have a contractual legal obligation to procure their apportioned share of capacity resources necessary, as assessed by the NWPP, to maintain overall regional RA in the short-term (from a period of days and weeks to months).[8] The NWPCC's regional assessment would still provide complementary, valuable insight into the long-term adequacy of the power supply in the northwest.

The existing NWPCC RA assessment answers the three policy questions described above by applying its evaluation to the entire northwest, adopting a 5 percent loss of load probability risk metric (more details below), and evaluating RA on an annual basis. Any program developed by the NWPP or another jurisdiction would similarly need to address those three key policy questions before undertaking a technical analysis of the adequacy of the power system.

Regional Evaluation of Resource Adequacy

> "While utility portfolios are typically designed to meet specified resource adequacy targets, there is no single mandatory or voluntary national standard for resource adequacy. Across North America, resource adequacy standards are established by utilities, regulatory commissions, and regional transmission operators, and each uses its own conventions to do so. The North American Electric Reliability Corporation (NERC) and the Western Electric Coordinating Council (WECC) publish information about resource adequacy, but have no formal governing role."
>
> E3, *Resource Adequacy in the Northwest* (2019) [9]

There is no one size fits all approach to how regions evaluate the adequacy of the power system. The following provides an overview of some of these approaches, which will serve as a foundation for the analysis of the key policy questions that follow:

Pacific Northwest

- Regional Assessment: The Northwest Power and Conservation Council (NWPCC) conducts an annual regional assessment of RA to evaluate the adequacy of capacity resources in the region to meet forecasted future demand for electricity for the next 5 years. The goal of this assessment is to "establish a resource adequacy framework for the Pacific Northwest to provide a clear, consistent, and unambiguous means of answering the question of whether the region has adequate deliverable resources to meet its load reliably and to develop an effective implementation framework."[10]
- Utility Specific Assessment: Consumer-owned utilities, investor-owned utilities, and their regulators in the northwest look to the annual assessment from the NWPCC to inform their own capacity planning analyses. The regional analysis from the NWPCC is influential, but does not impose any legal or contractual obligations upon specific utilities to procure new capacity resources should a regional deficit be identified. Each utility, with its regulators, determines whether it needs to procure additional capacity.

California

- Statewide: The California Public Utilities Commission imposes binding RA obligations on all jurisdictional Load Serving Entities, including IOUs, Energy Service Providers (independent power producers serving direct access customers), and Community Choice Aggregators (CCAs enable local governments to procure electricity for retail customers living within their jurisdiction). The CPUC program is designed to ensure that new resources are added to the grid in the specific areas needed by the California Independent System Operator (CAISO). Each LSE is required to make annual and monthly filings to demonstrate compliance with its RA obligations.[11]

Southwest Power Pool

- Southwest Power Pool (SPP): SPP covers portions of 14 states, stretching from northern Texas to North Dakota's border with Canada.[12] SPP evaluates RA across this wide geographic region, mostly served by vertically-integrated utilities, and identifies a need for capacity across individual regions and sub-regions for the summer peak season. It then allocates a portion of the responsibility for delivering this identified capacity need to individual utilities. The utilities either supply that capacity with utility-owned resources or secure capacity via bilateral contracts, a process which is overseen by and enforced by local regulators (either Public Utility Commissions or local public power governing boards).[13]

PJM Independent System Operator

- Reliability Pricing Model: PJM covers all of New Jersey, Delaware, Pennsylvania, Maryland, Washington D.C., Virginia, West Virginia, Ohio, and portions of six other states. The PJM Independent System Operator manages a capacity market known as the Reliability Pricing Model. The RPM is designed to send forward price signals that incentivize the retention of existing capacity resources, and the development of any new capacity resources necessary to "support the reliability and stability of the electric grid" to meet consumer demand.[14]
- RPM Auctions: While PJM is considered by many to operate a capacity market, it still relies on an administrative determination of need for new capacity resources. PJM develops a capacity market demand curve in a way that is designed to procure a certain amount of capacity at each price point on the curve. Where that administratively-determined curve intersects with the supply of capacity available in the RPM auction will determine the price and the quantity of the capacity that is cleared through the market. PJM designs its capacity market demand curve such that it is intended to procure enough capacity to meet, but not substantially exceed, the region's target planning reserve margin.[15]

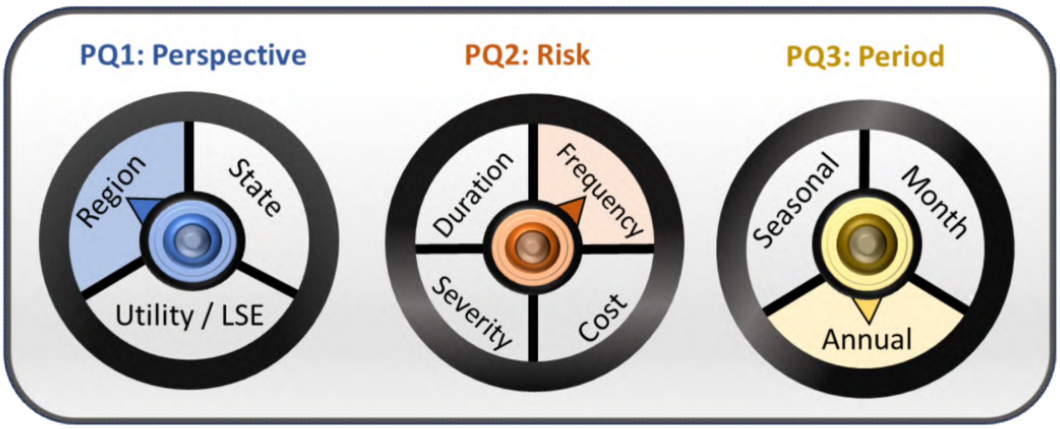
Texas

- Energy-Only Market: The Electric Reliability Council of Texas (ERCOT) manages the state's electric transmission system and operates electricity markets for 90 percent of the state.[16] Rather than having either utility-specific administrative capacity targets or a capacity market to drive the procurement of new capacity resources, ERCOT has adopted a very high cap on prices in its energy market ($9,000/MWh) instead. Developers should theoretically be willing to enter the market with new capacity resources if prices in the energy market are high enough for a sufficient number of hours.[17] ERCOT's energy-only market design, however, has failed to achieve its targeted level of reliability in five of the last ten years.[18]

Key Policy Questions

As described above, a utility or a region must evaluate several key factors (e.g., load forecast, weather conditions, supply constraints, climate impacts, etc.) to ascertain whether there is likely to exist a shortfall of capacity needed to meet forecasted future electric demand. In many respects, these are primarily *technical* considerations.

Based on a review of different approaches to RA across the country, three key policy questions (PQ) stand out as foundational to establishing a framework within which a technical evaluation of RA can occur. The graphic below represents these three policy dimensions as dials, each of which can be adjusted separately. An entity can ultimately maintain a reliable power system regardless of how these questions are answered, but how they are answered can have a substantial impact on the portfolio of resources needed to maintain an adequate system and the costs of that system. This graphic appears throughout this section to help explain the key policy questions involved in evaluating the adequacy of the power system to meet future electric demand.



Each of these three policy questions is explored in more depth below, including an identification of how different regions of the country have set these dials in establishing their respective RA programs. While some of the pros and cons of different approaches are identified, this section does not make any recommendations on specific settings for any of these policies.

Policy Question 1 – Perspective

The first key policy question involves defining the boundaries around the geographic area to be assessed for RA. Evaluating RA across multiple utilities over a larger geographic footprint can be more efficient as it allows those utilities to essentially pool their risk to benefit from a diversity of customer demand and availability of supply. On the flipside, this expanded geographic approach creates a potential hazard of overestimating the resources that utilities in other regions will actually have available to share and could result in failing to develop enough capacity resources locally. Developing mechanisms or processes to share more accurate information (e.g., around potential transmission constraints or time delineated resource and load information) across regions can help to mitigate against these types of hazards.

Historically, vertically-integrated electric utilities would develop, own, and operate adequate generating capacity to meet the future electric demand of their customers. If utility-owned resources were inadequate to meet all needs, utilities would sign contracts for additional output from other resources. This essentially remains how investor-owned utilities maintain resource adequacy in the northwest today. For example, Oregon's investor-owned utilities, with oversight from the PUC, evaluate the adequacy of their available capacity resources (including market purchases and imports) to meet forecasted future need, then secure additional resources as necessary. For the state's consumer-owned utilities, the situation is somewhat different, primarily because nearly all of them rely heavily (exclusively in many cases) on the delivery of power from BPA to meet their customer's needs.

Some states (e.g., California and New York) have developed statewide RA programs that encompass multiple utility service areas. As described above in the California example, state regulators evaluate RA statewide and identify capacity targets that each utility is responsible for meeting through capacity procurements to contribute their share to the overall RA of the state's electric system.

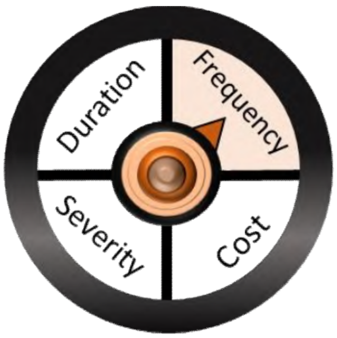
Many other regional electric systems operate within Regional Transmission Organizations (RTO) or Independent System Operators (ISO) that encompass multiple states. PJM and SPP, mentioned above, are examples of this type of an arrangement. In these cases, RA is evaluated across the multi-state regional footprint of the RTO or ISO, but also considers more local evaluations of adequacy.

There are several key considerations for policymakers when choosing the altitude or perspective at which to evaluate RA. Ultimately, a prescribed level of long-term power system reliability can be achieved under a variety of circumstances for a cost. Historically, Oregon utilities have evaluated RA across their own service territories for their cost of service retail customers (see the Resource Adequacy 101 for a discussion of the impact of customer choice programs on maintaining RA). Utilities in other areas of the United States, however, have often found engagement in a more structured RA program across a broader geographic area to be more cost-effective. Policymakers need to consider how the perspective for assessing RA can impact the cost to electric ratepayers of having a reliable power system.

- **Resource Diversity:** Some resources (such as hydropower or solar) might be more abundant in certain geographic locations than others. How much benefit can be gained by giving individual utilities access to capacity resources across a broader geographic region to benefit from the diversity of the output of different resources?
- **Load Diversity:** Similarly, some areas within a state or region might have significantly different weather from one another that results in substantive differences in the demand for electricity between those areas. Coastal areas of Oregon, for example, have milder weather and flatter demand for electricity than in areas of Eastern Oregon. How much benefit can be gained by allowing utilities to benefit from this diversity of load when evaluating resource adequacy?
- **Resilience:** Much of the electric generating capacity in Oregon today exists along the Columbia River, from the Bonneville Dam east to Hermiston. Those resources deliver power over long distance transmission lines to serve electric demand in the Willamette Valley, coastal areas, Southern Oregon, and beyond. Are there advantages to having more capacity resources

dispersed across a broader area to improve the resilience of the power supply within specific load pockets?

Policy Question 2 – Risk



How different regions of the country evaluate RA at the utility, state, or regional level was reviewed above. In each case, a specific RA standard must be applied against which the adequacy of capacity to meet future electric demand is measured. Due to the challenges associated with predicting future conditions, any RA standard will necessarily incorporate elements of uncertainty or risk.

The first development of a long-term power reliability target that's based on a probabilistic expectation of the inability to serve load a certain number of hours per year is often credited to Giuseppe Calabrese's *Generating Reserve Capacity Determined by the Probability Method*, published in 1947.[19] [20] In the decade that followed, several other technical papers were published in the industry that seemed to settle on a long-term reliability standard of "1-day-in-10-years" (or 2.4 hours per year) as being reasonable.[ii] According to a recent paper on the topic by the National Association of Regulatory Utility Commissioners,[21] those papers from the middle of the last century, while converging upon this standard, did not provide a basis of analysis for *why* this standard was appropriate. Following its formation in 1968, the North American Electric Reliability Corporation (NERC) identified this long-term reliability standard for the industry and it was subsequently adopted by most regions of the country.[22] Some variation of this standard remains a popular risk metric for evaluating RA today, although different utilities and regions apply alternative metrics which will be reviewed in more detail below.

Some variation of a "1-day-in-10-years" standard has long been established as the default long-term reliability metric for the electric industry. Several studies over the last decade, however, have called into question whether this standard is still appropriate, particularly given changes to the electric system from variable output renewables and the emergence of battery storage technologies.[23] [24] [25] [26] This standard has also been questioned due to the overall cost of maintaining the level of capacity necessary to meeting the standard. For example, the Brattle Group found that less than 1 percent of customer outages nationally are caused by inadequate generating capacity, while the remainder are primarily caused by outages on the transmission or distribution system.[27] This paper does not take a perspective on whether one risk metric or another is more appropriate for evaluating RA. The intention is to put this type of a risk metric into context, along with the other policy considerations involved in developing a comprehensive assessment of RA.

Ultimately, this policy question requires deciding: what tolerance for risk do we have when it comes to having inadequate capacity available to meet electric demand under certain future conditions? What are the key factors influencing this tolerance for risk?

[ii] This means planning the power system such that a combination of factors combine to result in inadequate generating capacity being available to meet electric demand no more than 1 day in every 10 years. Another way to state this standard would be no more than 24 hours in 10 years, or more simply, no more than 2.4 hours in 1 year.

Existing Approach in the Pacific Northwest

As described above, the NWPCC develops a regional assessment of RA in the northwest that many individual utilities use to inform their capacity procurement decisions. To develop that assessment, the NWPCC has adopted an RA standard based on a Loss of Load Probability (LOLP) metric of 5 percent. LOLP is a metric designed to approximate the acceptable probability, or the risk, of having inadequate generating capacity available to meet future electric demand.

The NWPCC's adequacy model performs a chronological hourly simulation of the northwest power system's operation thousands of times for a single future operating year, under a wide range of possible future conditions (e.g., temperature-sensitive demand, economic growth, wind and solar output, forced resource outages, and river flow conditions), and records each simulation in which at least one event occurs in which inadequate generating capacity is available to meet electric demand. To achieve the 5 percent LOLP standard requires the region to have enough modeled capacity available such that this inadequacy only occurs in 5 percent or fewer of the annual simulations. If that inadequacy occurs in more than 5 percent of simulations, the NWPCC can estimate the magnitude of the inadequacy by assessing how much additional incremental modeled capacity is necessary to return the region to 5 percent LOLP.

These model simulations are dependent on several highly uncertain inputs, such as forecasting economic growth and electric demand over a four-state region, or precipitation patterns and the impact on hydropower output. The uncertainty of these variables creates risk, which is why the NWPCC runs thousands of permutations to evaluate how the power system performs under even the worst-case combinations. The uncertainties of these key inputs, however, are not the types of risks that we consider here. Instead, we focus on the level of risk inherent in the application of the 5 percent LOLP standard itself compared to alternative metrics for evaluating RA.

Key Characteristics of Risk Metrics for Evaluating Resource Adequacy

The 5 percent annual LOLP metric used in the northwest is one among several different standards used to evaluate RA. In this instance, the metric measures the probability (or likelihood) that the region will experience at least one resource inadequacy event during the year being analyzed. The 5 percent LOLP, therefore, translates into the likelihood of at least one resource inadequacy event occurring in 1 year out of every 20.

The most commonly used risk metrics in the electric sector to evaluate RA focus on one of four key characteristics: frequency, severity, duration, or cost.

- **Frequency:** The loss of load event (LOLEV) metric measures the number of expected inadequacy events per year, where an inadequacy event is defined as a contiguous set of hours in which resources cannot meet demand. Although the NWPCC's adequacy standard is based on the annual LOLP metric, the NWPCC also calculates LOLEV along with metrics that measure the magnitude and duration of potential inadequacy events (see below). **Does our risk tolerance change based only on the potential frequency of inadequacy events across a year?**
- **Severity:** Another consideration concerns the severity of events when the region lacks adequate generating capacity to meet demand. The Expected Unserved Energy (EUE) metric measures the expected amount of unserved energy per year, in units of megawatt-hours. This

metric along with the LOLH (described below) are the adequacy metrics that NERC reports in its biannual probabilistic adequacy assessment publication.[28] NERC also reports normalized EUE, which is simply the expected unserved energy divided by the expected (weather-normalized) annual load, in megawatt-hours. The NEUE allows for the comparison of the severity of adequacy events across regions with vastly different sized loads. **Does our risk tolerance change whether a capacity inadequacy impacts delivery of energy to 1,000 residential customers for 24 hours, or 100,000 residential customers for 1 hour, or a single large customer for 4 hours?**

- **Duration:** The Loss of Load Hours (LOLH) metric measures the expected duration, in hours, of inadequacy events. NERC has standardized the definition of the adequacy metrics highlighted in this document (along with other less commonly used metrics) in a technical reference published in 2018.[29] **Does our risk tolerance change whether a capacity inadequacy lasts for 10 minutes, 10 hours, or 2 days?**
- **Cost:** Another consideration across any of these metrics involves cost. The more stringent a utility or a region makes its resource adequacy standard, the more it will need to invest in capacity resources to ensure that it minimizes the risk of inadequacy. The costs for these investments will ultimately end up recovered by utilities through customer rates. An uncommonly used metric in the United States is the Value of Lost Load (VOLL) that attempts to quantify how much customers are willing to pay to avoid having their demand for additional energy go unserved. The VOLL can be used as a measure of whether new investment in capacity resources is necessary.[iii] In other words, new capacity resources should be acquired only if their cost is *less than* the VOLL that would result from an inadequacy event. It should be noted, however, that VOLL by itself is not an adequacy metric and decision makers do not choose what the VOLL is – it is defined by customers. However, VOLL can be used to aid in adopting thresholds for other adequacy metrics. **Does our risk tolerance change depending on how much customers are willing to pay for higher levels of resource adequacy?**

Determining which of these characteristics is most important to electricity consumers is an important consideration when developing an RA program. Depending on which metric is selected, it can ultimately result in a more-or-less reliable power system, but it can also result in a more-or-less expensive power system. However, defining an adequacy standard need not be limited to using a single adequacy metric. For example, a much more robust standard would use all three metrics described above to set limits on the size, duration, and frequency of potential inadequacy events.[30]

Planning Reserve Margin

After using a probabilistic analysis—one that incorporates a distribution of possible outcomes for key variables—to identify a capacity target needed to maintain a selected RA standard, that amount of capacity can be compared to the system's historic peak demand. The *Planning Reserve Margin (PRM)* is a simple shortcut that has historically been used for this purpose in the electric sector to approximate how much capacity in excess of expected peak demand (often based on an historic evaluation of median peak demand) is needed to maintain an adequate power system:

[iii] An implied VOLL can also be derived post facto from the application of another RA standard. Irrespective of that existing standard, current levels of investment and actual occurrences of resource inadequacy can be used to calculate an implied VOLL associated with maintaining current RA levels.

$$\text{Planning Reserve Margin} = \frac{\text{Capacity (MW) Needed to Maintain RA} - \text{Expected Peak Demand (MW)}}{\text{Expected Peak Demand (MW)}}$$

An application of the various probabilistic risk metrics described above to achieve a prescribed level of RA tends to result in a PRM in the range of 12 to 20 percent, although there can be wide variations in exactly how the PRM is calculated.[31] As a rule of thumb, this margin should allow approximately enough headroom in the system to account for unplanned outages of generators and historically unprecedented load excursions. The PRM is often reported as an easy-to-understand metric of how much "excess" capacity the system requires to maintain an adequate system.

Why not just use a Planning Reserve Margin?

Given the simplicity in calculating a PRM, one might wonder why not exclusively apply a PRM metric (e.g., evaluate historic peak demand, then simply add 12 to 20 percent) to ensure the adequacy of the power system? The main argument against this practice concerns the real-world complexity of the power system and the deployment of new technologies, such as high penetrations of variable output renewables, the adoption of EVs, and more dynamic demand-side resources.

The key technical questions introduced in Table 1 above highlight this complexity, including consideration of variability in both the availability of power supply and customer demand throughout the year. Given the wide range of potential outcomes to these questions and the distribution of the likelihood of any particular outcome occurring in a given year, the use of the PRM as a deterministic planning guide has significant limitations.

The use of a more sophisticated probabilistic evaluation, on the other hand, allows policymakers to have a much more robust understanding of how the power system is likely to perform under a wide range of future conditions. This understanding gives them better insight into the risk of a future combination of events (e.g., perhaps a combination of low water flow in the rivers that reduces hydropower output, combined with unusually divergent temperatures driven by climate change and an unplanned outage of a large thermal generator) leading to an inadequate amount of generating capacity being available to meet electric demand.

Policy Question 3 – Time Period

The third key policy question to consider when determining how to assess RA across a utility or a region involves the time period evaluated. In an ideal power system, one might imagine that all capacity resources could be available to operate at full output during every hour of the year (or 8,760 consecutive hours). The reality, of course, is significantly more complicated.

> "Because it maintains an annual design, PJM effectively imposes the same reliability requirement in both the summer and winter seasons even though winter peak load is substantially lower . . . Ignoring that reality means that summer-only capacity cannot participate without being matched with an equivalent amount of winter-only capacity. This results in inefficiently little reliance on summer-only resources, and inefficiently high procurement of annual capacity."
>
> NRDC, *Opportunities to More Efficiently Meet Seasonal Capacity Needs in PJM* (2018) [32]

Many, but certainly not all, thermal plants (e.g., coal, gas, and nuclear) are capable of operating near full output for most hours of the day and months of the year. But even thermal plants require downtime for routine maintenance and are subject to unplanned outages that can take them offline for days, weeks, or longer.

Hydropower projects, which dominate the power system in the northwest, can meet a significant amount of the region's capacity need on any given day. That said, these projects are energy-constrained because of their dependence on natural water flows that fluctuate (sometimes by a large degree) based on temperature, precipitation patterns, and season. Other types of renewable energy, like wind and solar, also have variable output, but can still contribute to the region's capacity need. A common method for assessing the capacity contribution of renewables is the evaluation of the effective load carrying capability (or ELCC) of the resource, which allows for a comparison of the coincidence of the variable output of the renewable resource with the power system's net capacity need.[33] The ELCC of a particular type of resource is not static and can change over time due to changes in the net capacity need, driven either by changes in load or the capacity contributions of other existing resources on the system.

On the flipside, peak demand for electricity can also look quite different from season-to-season, and even from hour-to-hour, depending on the time of year. Increasingly, net demand can also present a significant challenge given the need for fast-ramping supply resources that can accommodate significant changes in the output of solar power on the system over the course of several hours.[iv] Power planners need to assess RA in a way that ensures adequate capacity is available despite these variations in supply and in demand across different time periods. As a result, the time period

[iv] Net demand or net load refers to the total electric demand on the system net of what can be met by output from variable renewables like solar. As solar penetration grows, these changes in net load can become dramatic in the early morning (as solar output rises) and early evening (as solar output declines) and may require grid planners to acquire fast-ramping, flexible resources to maintain adequacy.

evaluated for purposes of maintaining adequacy could have a significant impact on the suite of capacity solutions identified.

Three different time periods for evaluating RA are:

- **Annual:** Many regions of the country evaluate resource adequacy on an annual basis. Planners will apply an RA standard (described in more detail above) to evaluate how often during a given year there is expected to be inadequate capacity available to meet demand.
- **Seasonal:** An alternative approach would be to evaluate RA on a seasonal basis. Such an assessment might find that one season is more likely than another to have the conditions present to create an RA issue. Given the ability of some resources (e.g., solar) to contribute more to capacity during some seasons than others, this has the potential to have a significant impact on the identification of capacity solutions.
- **Monthly:** A third, more granular approach would be to evaluate resource adequacy on a monthly basis. Similar to the seasonal evaluation, this could potentially narrow the time period further during which potential resource adequacy issues are most likely to occur. For example, if climate change results in reduced river flows as the summer months progress, perhaps RA issues will become more prevalent in August than in June.

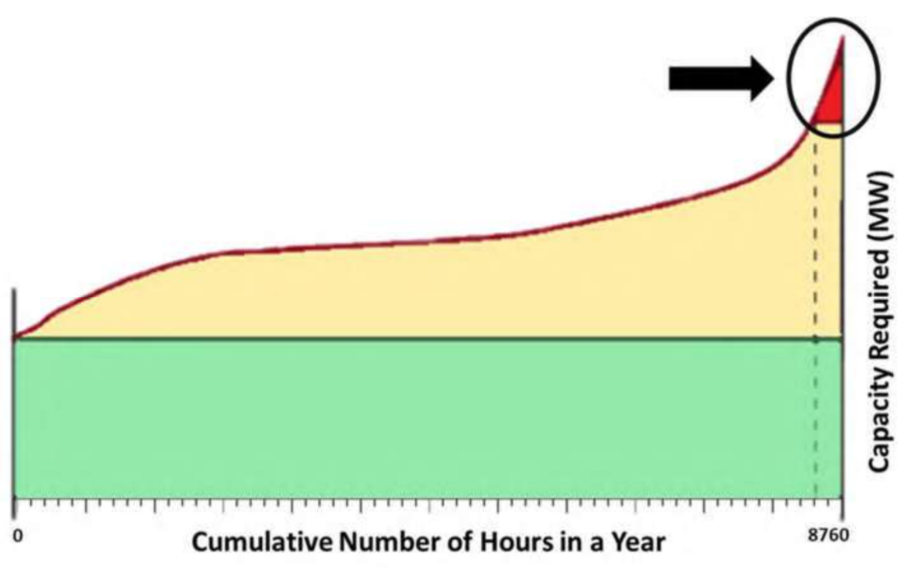
Note, however, that these time periods for evaluation can be, but need not be, mutually exclusive. The annual peak demand for a particular region may still occur in the summer months, for example, but the region may find its greatest capacity need exists in another season due to the particular characteristics of their system.

Conclusion

When Oregonians flip a light switch or plug-in an electric car, they have come to expect that the electricity they need will be there. For the vast majority of the hours in a given year, the power system can meet this need without much difficulty because the system is necessarily built to meet customer demand during those few hours (or days) of the year when peak demand occurs. What does this look like? Figure 1 depicts a graph of a hypothetical annual load duration curve that illustrates the point.

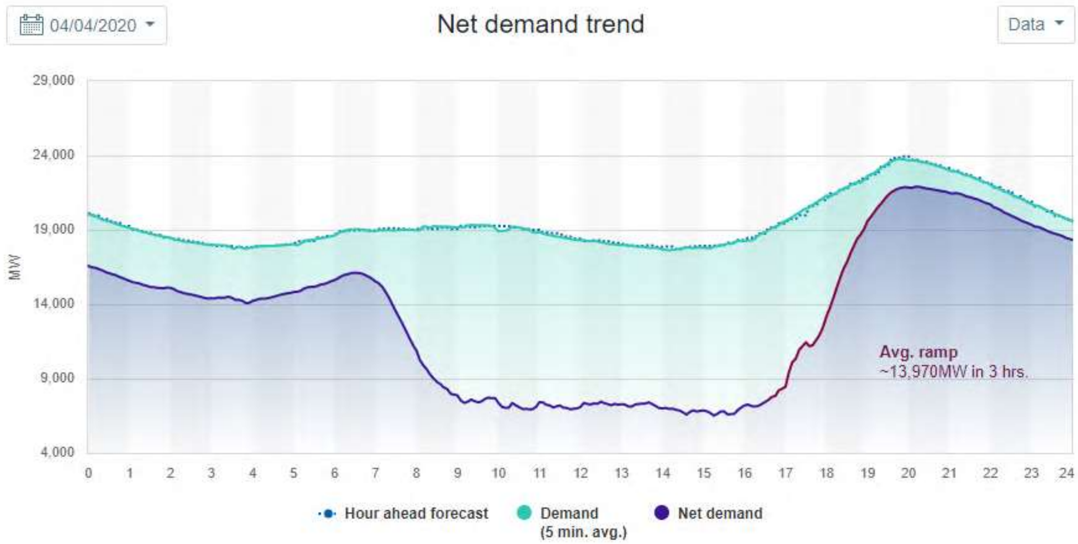
The evaluation of RA is often focused on the area circled in black here—those relatively few hours (or days) of the year when the capacity required to meet demand is the greatest. Utilities and grid planners must plan for capacity resources to be available to deliver electricity to customers when those times arrive.

Figure 1: Hypothetical Annual Load Duration Curve



Meanwhile, net demands on the system can present a related but different challenge for maintaining the adequacy of the power system. Consider the net demand load curve in Figure 2 from CAISO on April 4, 2020 which illustrates the impact of large penetrations of solar power on maintaining adequacy:[34]

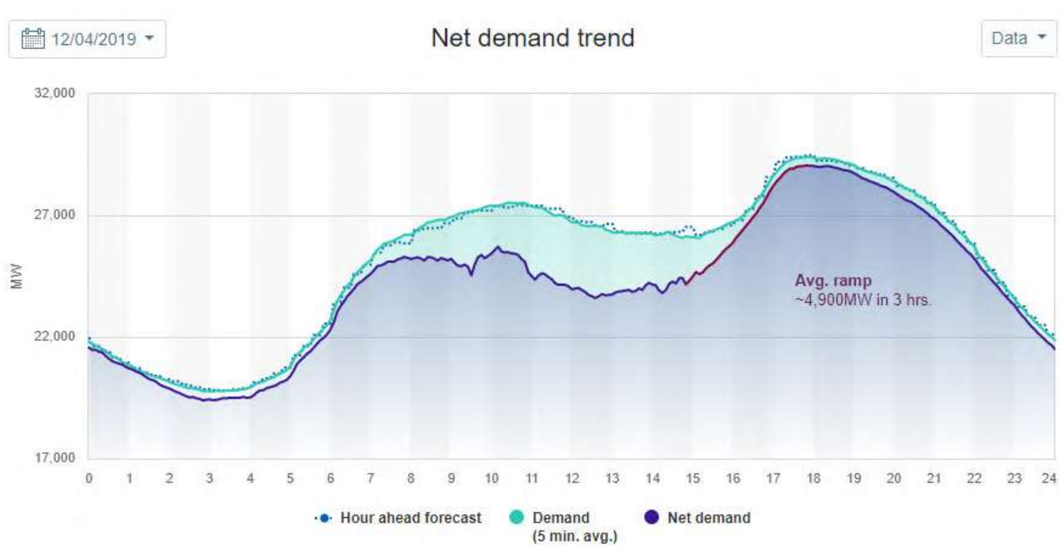
Figure 2: Net Demand Load Curve from CAISO in April 2020



On this day, the peak demand of 24,000 MW occurred around 8:00 p.m. So while grid planners needed to ensure that the system had adequate capacity to meet that 24,000 MW of peak demand (plus reserves), they also had to ensure that the system had adequate flexibility to quickly ramp up output from its non-renewable capacity resources by nearly 14,000 MW in the span of just three hours.

Now consider the same net demand curve from CAISO exactly four months earlier on December 4, 2019. Peak demand on that day was approximately 30,000 MW (or 25% higher than the day shown above) and occurred around 6:00 p.m., yet the ramp need of the system was significantly less at just under 5,000 MW in three hours (or only about 35% of the ramp needed on the day shown above):[35]

Figure 3: Net Demand Load Curve from CAISO December 2019



This section has identified several of the key technical considerations involved in evaluating the adequacy of the power system to meet these peak demands (and increasingly net demands) and explored in detail three key policy questions underlying this technical analysis. There are no right or wrong answers to these questions when evaluating RA, but as noted previously, different answers can result in different solution sets, or potentially different costs for maintaining the same level of adequacy of the power system.

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