2022 Integrated Resource Plan Preliminary Findings

1 Summary

The Integrated Resource Plan (IRP) is a tool to help us plan for an uncertain future so that we can continue to meet our customers' needs for decades to come. Per Washington state law, we complete a full refresh of the IRP every four years and make small updates in the interim every two years. We completed our last full refresh of the IRP in 2020. Our 2022 IRP will be an update to our 2020 IRP. This document presents preliminary findings on our resource position. These findings are:

1. In order to maintain reliability, we need to renew our Bonneville Power Administration (BPA) contract in 2028 or replace it with another set of resources equivalent to approximately 550MW of pure "always-available" capacity.
2. Our current BPA product (Slice/Block) still looks like it will provide enough resources to meet customer needs into the future assuming the terms of the next BPA contract are similar to today.
3. The conditions under which we are most at risk of experiencing shortfalls are (a) in the winter, (b) when we experience a combination of poor water conditions and high winter loads and (c) when the rest of the grid does is tight on capacity.

2 Background

2.1 About this document

This document is a more technical version of the Tacoma Public Utility Board (PUB) study session presentation we will give on April 13, 2022. The goals of the presentation and this accompanying document are to (1) provide an update on our plans for the 2022 and (2) provide an early look at what our preliminary analyses are showing.

2.2 About our Integrated Resource Plan

The Integrated Resource Plan (IRP) is a tool to help us plan for an uncertain future so that we can continue to meet our customers' needs for decades to come. Findings in the IRP represent our resource plan based on the best information available at the time of its creation. However, the plan may change as new information becomes available. Per Washington state law, we complete a full refresh of the IRP every four years and make small updates in the interim every two years. We completed our last full refresh of the IRP in 2020. Our 2022 IRP will be an update to our 2020 IRP. Our 2022 IRP will maintain the same basic modeling framework and scenarios as the 2020 IRP but will rely on updated inputs for prices and loads. We will also adjust how we model certain resources in our system model. Past IRPs, including the 2020 IRP, are available on our IRP webpage.

2.2.1 2022 IRP focus areas

We will ask some of the same questions in 2022 as we did in 2020 but will also consider some new questions that were less pressing in 2020.

1. **Updated BPA contract renewal analysis:** Our largest power purchase contract is with Bonneville Power Administration (BPA). Our current contract with BPA ends on September 30, 2028. Our 2020 IRP took a first

look at the questions of whether to renew our contract with BPA in 2028, which BPA product might best meets our needs in the future and whether there might be value in diversifying our portfolio to be slightly less reliant on BPA in the future. We will continue to evaluate these questions over the next few IRPs as the 2028 date approaches.

2. **Updated analysis on the impacts of climate change:** Our 2020 IRP took a first attempt at including climate change projections directly into our system model. In our 2022 IRP, we plan to repeat this analysis and aim to refine how we incorporate available climate projections into our modeling.
3. **New preliminary analysis on the impacts of accelerated vehicle & building electrification:** As the market for electric vehicles continues to expand and local and state legislation encouraging vehicle and building electrification expand, the possibility of large load increases due to electrification is becoming increasingly likely. The 2022 IRP will take a first look at the potential resource adequacy impacts of accelerated of vehicle and building electrification. In the 2022 IRP, we will treat the analysis as a separate stress test and will assume high rates of electrification. We anticipate including vehicle and building electrification projections directly into our core scenarios in the 2024 IRP[1].

2.2.2 Community Input Process

As part of every IRP, we hold a community input process. The objectives of the this process are to (1) educate stakeholders about Tacoma Power's long-term planning process and key industry developments that affect that process, (2) seek feedback on key IRP assumptions, approaches and products, (3) seek input from stakeholders about what their priorities are so that we can consider them in our planning process and (4) inform stakeholders about key milestones in the IRP process (release of draft documents, upcoming workshops, etc.)

IRP workshops have traditionally been the primary focus of the IRP public process and remain our primary outreach tool for the 2022 IRP. Our IRP workshops are open to the public, and anyone is welcome to participate. We advertise the workshops to all of our customers (e.g. on our website) but make a concerted effort to secure participation from individuals representing key interests in the community in order to ensure a diversity of perspectives (different customer classes, environmental and economic justice interests, external expertise, etc.). All workshops for the 2022 IRP process are being held virtually. As of April 2022, we have held two workshops for the IRP and plan to hold two more (one on June 30 and one on July 19). All workshop materials (slides, notes and meeting recording) are posted to the IRP webpage after completion of each workshop.

2.2.3 Overview of IRP modeling framework

Our IRP modeling process has four key steps:

1. Model resource build in the Western Electric Coordinating Council (WECC) region for each of the future scenarios considered in the IRP using the capacity expansion functionality in the commercially available AURORA modeling software tool;
2. Model WECC-wide prices and other outcomes given a particular capacity expansion using AURORA;
3. Simulate dispatch of the Tacoma Power system given a particular set of prices, loads and water conditions using a home-built model called SAM;
4. Post-process outputs from SAM to calculate resource adequacy metrics, portfolio costs, financial risk and emissions using a variety of tools (Excel, R, Stata, Python, etc.).

[1] Section 2.2.5 explains our 2020 and 2022 IRP scenarios in more detail.

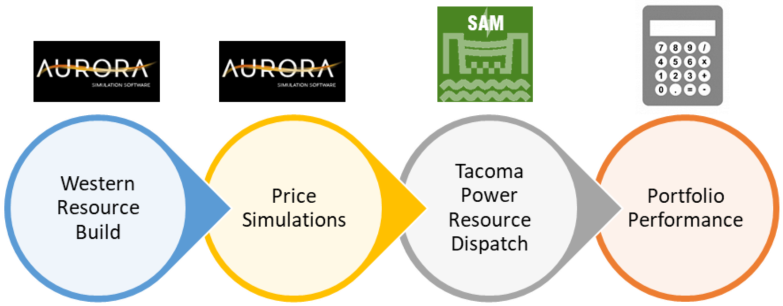

FIGURE 1: OVERVIEW OF TACOMA POWER IRP MODELING PROCESS

2.2.4 About our System Model (SAM)

SAM is an in-house software tool built to model our hourly generation similar to how we operate our system. The inputs into SAM are inflows, loads, future scenarios, and energy prices. SAM is a deterministic model, meaning it provides outputs based on a single set of loads, prices and water conditions. However, we run many different simulations of loads, prices and water conditions within SAM to create a set of probabilistic outputs.

Within SAM, resources dispatch independently of one other. Currently, we model existing Tacoma Power-owned resources such that each resource has its own set of constraints that must be met in every hour. Examples of constraints include target water elevations levels, maximum discharge, and amount of operating reserves to carry. Other resources, such as wind and solar, are represented by hourly energy profiles.

2.2.5 Accounting for Uncertainty

Like many IRPs, our IRP looks 20 years into the future. It is difficult to predict what conditions we might face even five years from now, let alone in twenty years. The IRP addresses the uncertainties we face in the future in two key ways. The first approach deals with the normal year-to-year variability we might expect to see expect to see through **stochastic analysis**. It takes into account variability in streamflow conditions, temperatures (which affect load), and natural gas prices (which are a major determinant of power prices). The second approach, **scenario analysis**, envisions alternative futures where we change our key assumptions about the future trajectory over time of inputs like load growth, renewables costs or natural gas prices. Our 2020 IRP considered four scenarios, and our 2022 IRP will consider the same four scenarios:

1. **Cruise Control**, in which environmental policies continue as they exist today with no additional changes.
2. **Carbon Policy Accelerates**, in which renewable energy policies are extremely strong and spread to almost every state in the WECC.
3. **Technology Solves Everything**, in which renewable energy policies are also strong, but costs of clean energy technologies are very low and the WECC is able to cost effectively integrate large amounts of renewable resources.
4. **Reliability Reigns**, in which poor planning and challenges with integrating renewables lead to a roll back of clean energy policies in 2030 in an effort to restore grid reliability.

For each scenario considered in the IRP, we run 58 weather years (which includes both inflow conditions and temperatures seen in a historical calendar year) in combination with 5 different gas risk runs (which yield different wholesale market prices). All together, we run 1,160 simulations across our four core scenarios. In addition to these four scenarios, we run additional simulations for separate sensitivity analyses (e.g. impacts of climate change, load increases due to vehicle and building electrification, etc.).

2.3 Updates since 2020

2.3.1 Price simulations

AURORA regularly releases updates to its database and modeling tool to reflect changes to technology costs, technology availability, natural gas price forecast, load forecasts and carbon policy, among other things. The 2022 IRP uses an updated version of AURORA. In addition to the standard AURORA updates, we adjust loads across the WECC to account for weather in each of the 58 historic weather years 1950-2007. Because of limited information available for Canada, the Canadian zones, Alberta and British Columbia were not weather-adjusted.

2.3.2 System model

In addition to updating our power price assumptions, we have made several improvements to our system model, including updating our assumptions on how loads will change over time, modeling updates to better reflect how we operate our hydropower projects, and refinements to how we model wind, solar and demand response resources.

3 How we assess portfolio performance

We assess portfolios using several metrics. While the metrics we use evolve over time, they always include two fundamental criteria: (1) that portfolios leave us with enough resources to meet customer needs (resource adequacy) and (2) that costs are as low as possible given other constraints and priorities. For the 2020 and 2022 IRPs, we assess portfolios based on five metrics:

1. Resource adequacy
2. Compliance with Washington's Clean Energy Transformation Act (CETA)
3. Expected portfolio cost
4. Financial risk
5. Carbon emissions

The first two criteria (resource adequacy and CETA compliance) are treated as hard constraints, meaning that portfolios must meet these criteria to be a viable portfolio. Other criteria are considerations that help us select the best option.

3.1 Resource adequacy

A resource adequacy (RA) standard tests whether a utility has enough resources to meet loads based on some objective criterion. In our 2020 IRP, we updated our standard to reflect evolving best practices in resource planning and settled on a standard that addresses three dimensions of potential adequacy risk: magnitude, duration and frequency of potential shortfalls:

1) **Magnitude standard:** Annual expected capacity shortage of no more than 0.001% of load per year (NEUE of 0.001% per year).
2) **Duration standard:** No more than 2.4 hour of capacity shortage per year (LOLH of 2.4 hours per year).
3) **Frequency standard:** No more than 2 days with a capacity shortage of any magnitude or duration every ten years, or 0.2 days per year (LOLD of 0.2 per year).

If a portfolio meets all three standards, we consider it adequate. If it fails to meet one of the standards, we consider it inadequate. Because our 2022 IRP is an update, we will use the same resource adequacy standard as our 2020 IRP. Our 2024 IRP will take a fresh look at our standard once again.

3.1.1 Update to market reliance assumption

A critical assumption built into resource adequacy calculations is the extent to which a utility can rely on the wholesale market to buffer potential inadequacy events. For the 2020 IRP, we assumed that up to 50MW of power could be purchased from the wholesale market at any time (the same assumption that it used in the 2015 IRP and 2017 IRP update). For the 2022 IRP, we developed a more nuanced assumption that ties our market reliance assumption to the market implied heat rate[2]. When calculating whether we are able to supply sufficient power in a given hour, we consider the heat rate in that hour for a particular run and determine the extent to which we would be able to rely on the market. When heat rates are low, we do not place any limit on our ability to rely on the market for capacity. This will mean that we never find ourselves at risk of shortfalls in hours with low heat rates. When heat rates are very high, we do not allow any reliance on the market. When heat rates are somewhat high, we allow some limited reliance on the market (either 50MW or 25MW, depending on what the heat rate is).

3.2 CETA compliance

Any portfolio we acquire must meet the requirement that at least 80% of our load is served by renewable and nonemitting power. CETA will eventually require that 100% of load be served by carbon-free power by 2045, but that is outside of the 2022 IRP study period. In the absence of rules on how exactly the 80% requirement would be calculated, we did our best to estimate CETA compliance in the 2020 IRP. Since then, the Department of Commerce has released draft rules with more detail on how this 80% requirement should be calculated. We plan to update our calculations as needed to reflect these draft rules but do not expect it to change the general finding that our current portfolio is already in compliance. In future IRPs, once the rules for how CETA will treat market purchases are settled, we will begin to address CETA compliance post-2045.

3.3 Other metrics

The final three metrics we consider are portfolio cost, financial risk and carbon emissions. The expected cost of each portfolio is calculated as the net present value (NPV) of portfolio costs, averaged across all simulations, and financial risk is measured as the average cost across the 10% highest-cost outcomes in each year.

For most of the portfolios we consider, the only mechanism through our portfolio would have any carbon emissions associated with it is through purchases we make on the wholesale market or through similar purchases made by BPA that are passed through to Tacoma Power. Because short-term markets do not tag which generator was used to produce the power one is buying, it is not straightforward to estimate how carbon-intensive those purchases are. For simplicity, we assume that the carbon intensity of market purchases is equal to the average of the marginal emissions rate at the Mid-Columbia trading hub modeled in each year for each scenario in our AURORA model. For emissions associated with the BPA contract, a fixed mix of resources is assumed based on BPA’s most recent official fuel mix report. While this assumption is unlikely to be accurate, modeling the potential changes in the share of BPA’s portfolio that will come from market purchases under different future scenarios and water conditions was unnecessarily complex given the small amount of emissions associated with the BPA contract.

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[2] The heat rate is equal to the power price divided by the natural gas price. It provides a useful indicator of what is happening with power supply and demand in the market. When heat rates are high, there is generally less capacity available on the grid and vice versa.

4 PRELIMINARY FINDINGS

4.1 RESOURCE NEED

Because 2028 was many years away, our recent IRPs prior to 2020 assumed that we would renew our BPA contract. While all of the analyses we have completed to date suggest that renewing our BPA contract in 2028 is likely to be the lowest-cost, least-risk approach to continue meeting customer demand into the future, the 2022 IRP assesses our resource need without assuming that we renew BPA in 2028. We then consider all of our options for meeting that need, including renewal of our BPA contract.

Figure 2 through Figure 4 present resource adequacy results for our portfolio without contract renewals for each of our three resource adequacy metrics. The results indicate that simply letting the BPA contract expire without replacing it with anything would leave us severely inadequate in all future states of the world under all of our resource adequacy metrics. Without BPA (or something to replace BPA), we should expect to see large shortfalls in every year under all weather conditions and in all future states of the world. In our base case scenario, we are short by approximately 2% to 4% of load and see shortfalls in 10% to 20% of all hours in the year and in nearly one third of all days in the year. In our highest load growth scenario (Carbon Policy Accelerates), roughly 6.5% of load would go unserved and we would not have enough resources in nearly 30% of hours in the year and in over 40% of all days in the year. Even under our load decline scenario (Technology Solves Everything), we would still fail our adequacy standard in all study years.

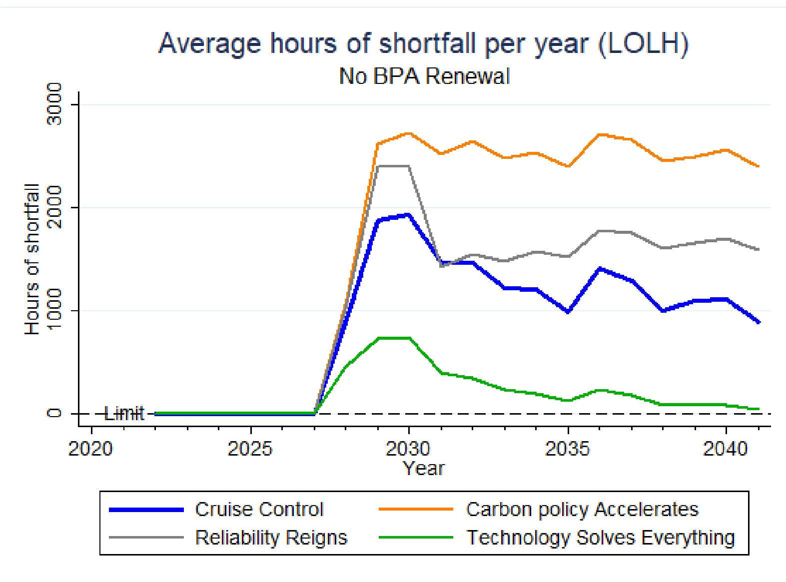

FIGURE 2: DURATION METRIC - AVERAGE HOURS OF SHORTFALL PER YEAR (LOLH)

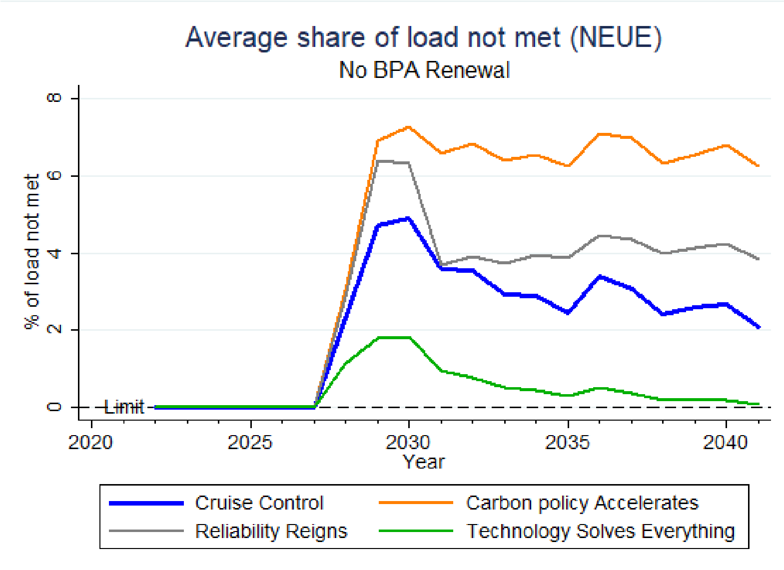

FIGURE 3: MAGNITUDE METRIC - AVERAGE SHARE OF LOAD NOT MET (NEUE)

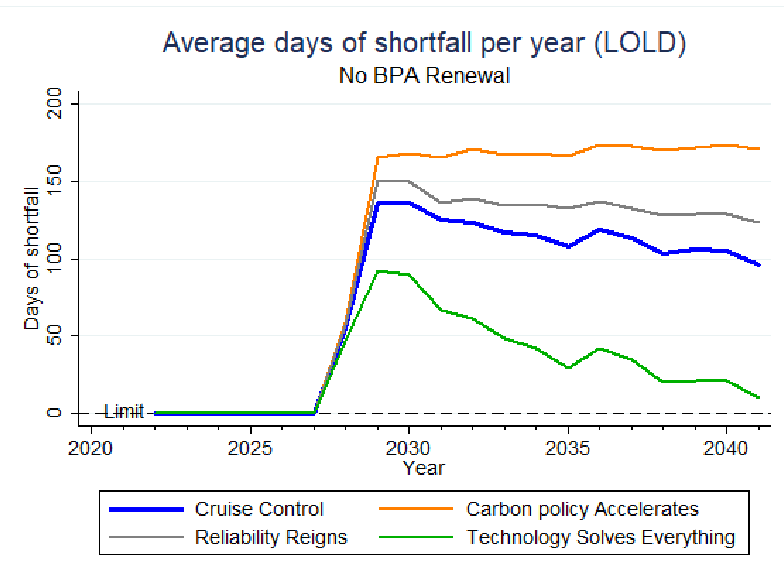

FIGURE 4: FREQUENCY METRIC - AVERAGE DAYS OF SHORTFALL PER YEAR (LOLD)

4.1.1 How big is the need?

We conducted an analysis to get a general sense of how large our resource need is without renewal of the BPA contract. We progressively added pure capacity to the system until we reached a point where we passed our adequacy standard. Table 1 summarizes the amount of pure capacity needed in each scenario to meet our adequacy standard in all calendar years. To ensure that we are adequate across all possible futures, we would need approximately 550MW of pure capacity if we were to decide not to renew our BPA contract in 2028[3]. The scenario

[3] This is the capacity required to meet the most stringent of our three metrics—our frequency standard. We would need slightly less to meet both our duration (LOLH) and magnitude (NEUE) standards in all scenarios.

that requires the largest capacity addition is our "Carbon Policy Accelerates" scenario, in which we project the highest growth in load.

We use the term "pure capacity" to mean capacity that is available 100% of the time without interruption. Most of the resources considered in the IRP do not provide pure capacity. For example, wind typically provides capacity equivalent to about 25% to 30% of its maximum generation (i.e. a 100MW wind plant may provide the equivalent of 25MW to 30MW of capacity). This assessment of need is useful primarily as a point of reference to begin estimating what it would take to replace BPA with other resources.

TABLE 1: RESOURCE NEED UNDER FOUR SCENARIOS OF THE FUTURE

Scenario	Pure capacity needed to meet adequacy standard in all calendar years
Cruise Control	Approximately 500 MW
Carbon Policy Accelerates	Approximately 550 MW
Reliability Reigns	Approximately 550 MW
Technology Solves Everything	Approximately 500 MW

5 PORTFOLIOS WE WILL CONSIDER

We plan to consider three major types of portfolios:

1) **Portfolios in which we renew our BPA contract at current levels:** This set of portfolios includes options where we renew our BPA contract in 2028 with the same product as we currently purchase from them (the Slice/Block product) as well as two to three other product options.
2) **Portfolios in which we renew our BPA contract at a lower level in an effort to diversify our future resource supply:** This set of portfolios includes options where we renew our BPA contract with one of the above BPA product options but also acquire another resource that would offset slightly the amount of Block we would receive from BPA.
3) **Portfolios in which we renew our BPA contract at current levels and add resources to address resource adequacy shortfalls:** We will likely need to consider these portfolios in cases where we model substantial additions to load (for example, in our electrification sensitivity analyses).
4) **Portfolios in which the BPA contract is not renewed:** We plan to run several portfolios to consider this option. However, we may find that it is not technically feasible for us to completely replace BPA with other sources of carbon-free resources given factors like transmission availability.

5.1 PRELIMINARY RESULTS FOR OUR CURRENT PORTFOLIO (SLICE/BLOCK)

We start by looking in-depth at performance of the Slice/Block Only portfolio (i.e. continuing with our current portfolio), as previous IRPs and other analyses have consistently found it to be the portfolio most likely to meet our needs and keep customer costs low into the future. We find that our current portfolio passes all three of our resource adequacy standards under all scenarios of the future except for at the very end of the study period (2040) in one scenario (Carbon Policy Accelerates) (Figure 5 through Figure 7). Because this one instance of failing our standard takes place at the very end of the study period and in only one scenario, it is of minimal concern. We conduct a new IRP analysis every two years and have plenty of time to adjust to conditions leading to this single instance of failing our standard 19 years in the future.

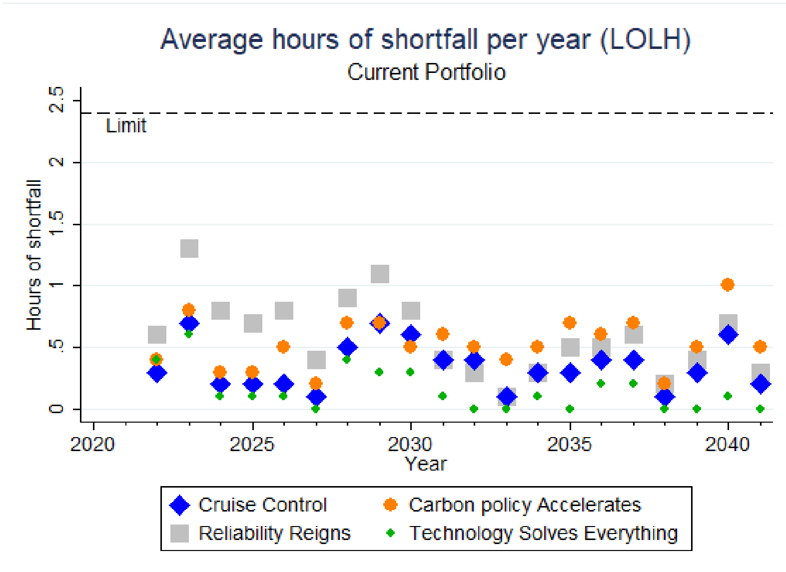

FIGURE 5: RESOURCE ADEQUACY POSITION WITH CURRENT PORTFOLIO - DURATION METRIC

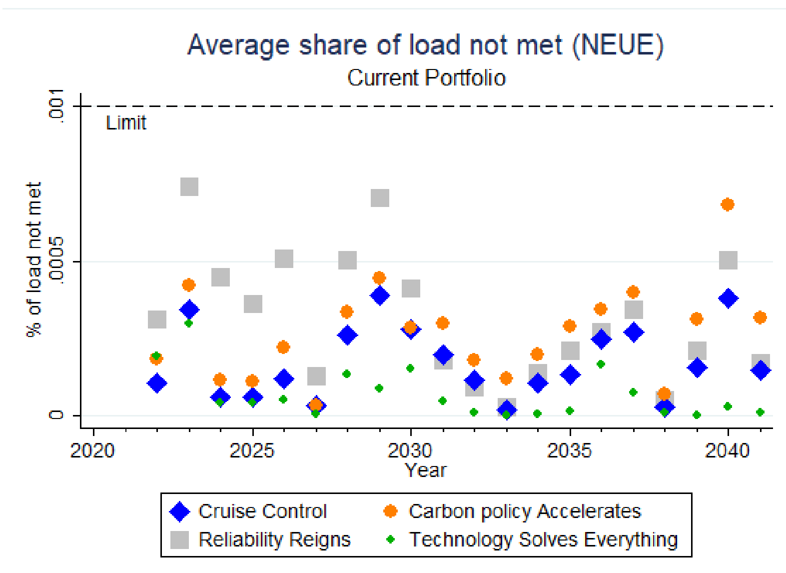

FIGURE 6: RESOURCE ADEQUACY POSITION WITH CURRENT PORTFOLIO - MAGNITUDE METRIC

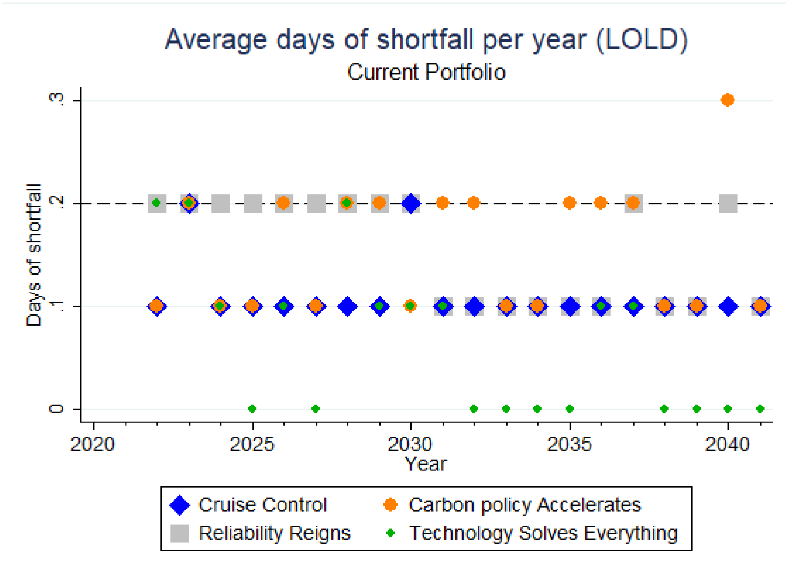

FIGURE 7: RESOURCE ADEQUACY POSITION WITH CURRENT PORTFOLIO - FREQUENCY METRIC

5.1.1 Drivers of Resource Adequacy Risk

Even though our current portfolio passes our adequacy standard across all scenarios for all but the very end of the study period, it is helpful to understand the conditions under which we are most at risk of shortfalls. This section of our analysis does not imply that we expect not to have enough resources to serve customer needs but rather is an effort to dive deeper to identify periods and conditions of highest risk to our system.

Time of year: As in previous IRPs, we find that we are primarily at risk of shortfalls in the wintertime. Figure 8 presents the average number of days of shortfall our models find across weather years and Figure 9 presents the distribution of our load-resource balance (equal to the amount we generate minus our load) for our current portfolio under the Cruise Control scenario. Results are similar for other scenarios. Together these graphs tell us that we should expect to have less surplus energy available in the summertime but that there is less risk of not having enough power to meet customer needs. In the wintertime, although we typically expect large surpluses, there is greater variability in our position and we sometimes are at risk of being short on capacity and energy. It is important to note that these preliminary results reflect historical weather only and do not take into account changes in weather and inflow patterns due to climate change. We will include an analysis of how our results might differ as the climate continues to change once we incorporate data on the projected temperature and water inflow impacts of climate change into our model.

Water & Load Conditions: We generally find that shortfall risk is not due exclusively to low water conditions or high load but rather the combination of the two. For the most part, our system is able to handle our normal loads even under low water conditions and is able to handle relatively high loads under normal water conditions. It is when we experience especially low water conditions combined with a drop in temperature (and the resulting spike in load) that we are at risk. We go through two examples in Section **Error! Reference source not found.** below.

Market conditions: A key assumption built into our analysis is that we are able to purchase power from the wholesale market sometimes. As described in Section 3.1.1, we assume that we can purchase from the market to varying degrees depending on the market heat rate. While we pass our adequacy standard in all four of our scenarios of the future, we find that shortfalls are more likely in our Reliability Reigns scenario. This scenario represents conditions in which the WECC fails to build enough capacity to meet West-wide adequacy needs and, as a result, we are less able to rely on the wholesale market as a backup to our own power supply. In recent years, we have seen several indications that capacity may not always be plentiful in the market. We actively participate in efforts like the Western Resource Adequacy Program (WRAP) to ensure that the region builds sufficient capacity and avoids market conditions represented in the Reliability Reigns scenario. Should these efforts fail, we are likely to find market conditions that increasingly resemble this higher-risk scenario.

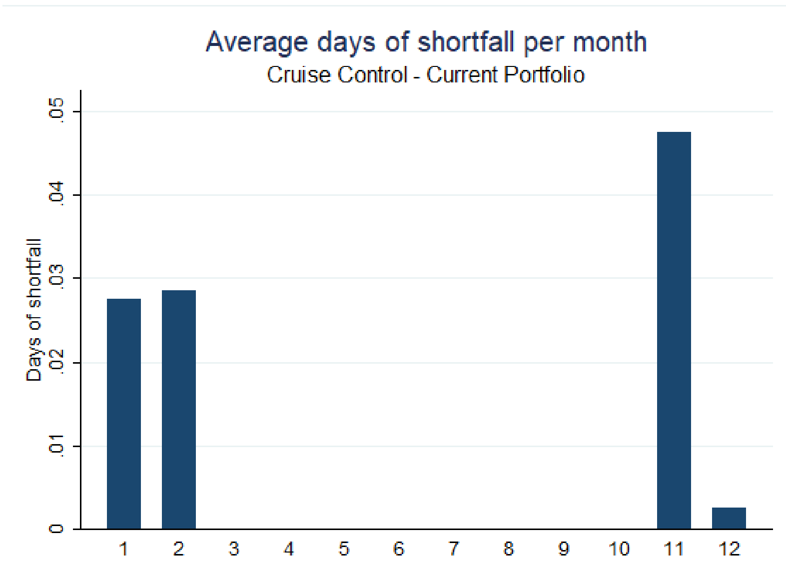

FIGURE 8: PERIODS OF SHORTFALL RISK UNDER CURRENT PORTFOLIO

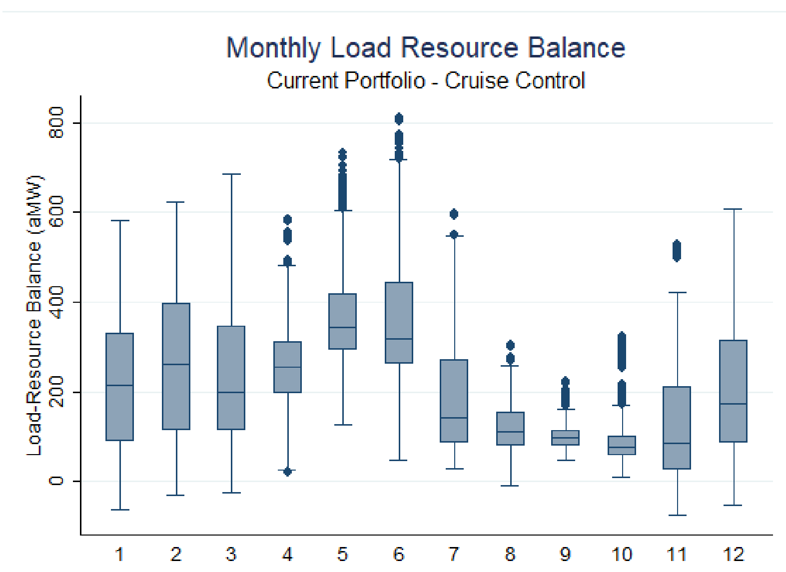

FIGURE 9: MONTHLY LOAD-RESOURCE BALANCE WITH CURRENT PORTFOLIO

6 IMPACTS OF CLIMATE CHANGE

Our 2020 IRP made a first attempt at including climate change projections directly into our system model. Because we have more work to do to determine how best to incorporate climate change projections into our modeling, our

2022 IRP will continue to address the impacts of climate change in a sensitivity analysis. This is not due to doubt over whether climate change will impact our resource needs but rather the need to evolve our approach to reflect those impacts.

In our models we rely on the best and most complete projections on the impacts of climate change on Northwest streamflows, produced by a team of climate and hydrology researchers from Oregon State University and the University of Washington for a 2018 Columbia River Climate Change (CRCC) study funded primarily by BPA with additional funding from the United States Bureau of Reclamation and the United States Army Corps of Engineers.[4] This study produced a wealth of climate change projections. Altogether, the CRCC study produced 43 separate projections of outdoor air temperature and 172 separate projections of streamflows through the year 2099 for 172 sites in the Northwest, including Tacoma Power's project sites. Unfortunately, we cannot reasonably incorporate 172 separate sets of streamflow projections due to computational time. In 2020, we opted to build off work done by the NW Power and Conservation Council to determine which of the 172 models to incorporate into its modeling for the 2021 Power Plan. They opted to use three different sets of projections. We opted to do the same for our first attempt at incorporating climate change into our IRP modeling in 2020 and plan to, at a minimum, use the same three climate models in our 2022 IRP. However, we plan to augment the number of climate models we consider. If time permits, we will do so in this IRP. Regardless, we will reassess our choice of climate models and our general approach to incorporating climate change into our modeling for the 2024 IRP.

6.1 Preliminary findings

Our preliminary model outputs suggest trends that are to what we saw in our 2020 IRP. Warmer temperatures generally lead to lower winter loads and higher summer loads, but certain years in certain climate models see extreme low temperatures below what we have seen historically. These more extreme winter lows sometimes translate into strain on our system. We also observe significant changes in the shape of inflows into our projects and into BPA's reservoirs. Generally, we see higher inflows in the wintertime and spring and lower inflows in the spring and fall, as more precipitation comes down as rain and less is stored as snowpack relative to historical weather conditions. We continue to see a great deal of variability in winter inflows.

So far we are finding that the changes are large enough to improve our winter resource position (due to the combination of more water and lower loads) in most cases but not large enough to create new resource deficiencies in the summertime. However, we may find a new summer risk emerge as more and more homes purchase air conditioning.

7 Next Steps

This document presents preliminary results from our 2022 IRP modeling work. Over the next several months, we will continue to refine and expand upon this work by completing the analyses described in Figure 10 below. We will return to the Public Utility Board on July 13 to present near-final findings and recommendations in study session and seek formal approval of the IRP at the August 10 Public Utility Board meeting. Assuming the IRP is approved in August, we will then submit it to the Department of Commerce by September 1, 2022.

[4] https://www.hydro.washington.edu/CRCC/

BPA Renewal

- Portfolios capable of replacing BPA
- Costs vs. benefit of different BPA products
- Is there value in diversifying away from BPA a little more?
- Risks of BPA contract (Snake River dam removal, climate change, etc.)

Cost analysis

- Which portfolios are most cost-effective for our customers?

Impacts of climate change

- Modeling under way but still vetting results

Impacts of electrification & large electrofuel load

- Preliminary look at potential impacts on load complete
- Next will incorporate into system modeling

FIGURE 10: UPCOMING ANALYSIS WORK