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A Review of Water and Climate Change Analysis in Electric Utility Integrated Resource Planning

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Executive Summary

The purpose of this paper is to examine the extent to which electric utility integrated resource plans (IRPs) evaluate the impact of water constraints on electric generation resource portfolios and the extent to which IRPs consider the impacts of climate change to generation and loads. This white paper reviewed 30 IRPs to determine best practices with respect to analyzing and reporting on potential water-based and climate change risks within the integrated resource planning process. Best practices from electric utility IRPs are identified and additional recommendations and considerations are put forth.

In recent years, thermal generating facilities have experienced challenges with water availability: a shortage of cooling water, conditions in which incoming cooling water is too warm for optimal operation, and/or water discharge temperatures exceeding permit limits. S&P Global Market Intelligence recently reported on a study that identified for the year 2030, 98.2 gigawatts (GW) of coal capacity at risk due to water stress (Kuykendall and Whieldon 2020). Climate change effects on hydrological cycles may adjust the timing, temperature, and volume of water availability for thermal electric cooling and for hydropower generation, which could further exacerbate the frequency and duration of operational constraints. Climate change can also impact the timing and intensity of electric loads that utilities must serve, most notably for heating and cooling.

The best practices identified in IRPs include the following:

- Development and presentation of a plan showing that the IRP examined water availability and includes plans to ensure sufficient water will be available for all thermal generating resources dependent upon water supplies for cooling.
- Use of water consumption for power plant cooling as a metric for selecting the preferred resource portfolio, and particularly using targets for the use of constrained water resources, such as groundwater, for selecting resource portfolios. The water metrics noted in the IRPs reviewed were included in general environmental or sustainability metrics. A more robust metric would evaluate water use as a constraining resource, identifying the likelihood of a water constraint limiting resource availability or otherwise imposing costs to mitigate the constraint.
- Use of the IRP planning process to identify the best path forward for resources facing water stresses, and to weigh alternative costs and benefits and the impact on the overall resource portfolio.
- Use of a generating capacity metric that explicitly accounts for the impact of forced outages and deratings and, in particular, to capture expectations for outages related to water availability issues.
- Planning for the impacts of climate change on generating capabilities (especially in the case of hydroelectric-dependent utilities) and loads and ensuring the future portfolio matches changing future loads.
- Developing weather and water projections that take into account changes to historical patterns based on climate change, through using downscaled climate models, weighting projections more heavily on the most recent past (~15 years) rather than equally across the historical record, and/or conducting a customized regression analysis that addresses changes to weather patterns. An example presented in this paper, of an analysis conducted by the Northwest Power and Conservation Council (NWPCC) as part of a regional capacity

expansion planning exercise, found that loss-of-load probabilities varied significantly based on whether future load and resource projections were based on weather data from the distant historic record (1949–1978), more recent historical weather data (1979–2008), or from climate models projecting weather patterns from 2020–2029 (NWPCC 2021). This example points to the need for electric utilities to consider climate change impacts to generation and loads in resource planning, rather than basing future plans solely on the weather of the past.

- Considering the impact of climate change on load projections by evaluating the impacts to number and magnitude of heating-degree days and cooling-degree days and the potential for population and economic changes due to climate changes in the utility service territory compared to other parts of the country.

A recent study conducted by Pacific Northwest National Laboratory (PNNL), National Renewable Energy Laboratory (NREL), and the University of Washington studied the impact of climate change on water availability and its propagation through the Western U.S. power grid. The study found that changes in water availability in one region trigger a response in other regions and that regional dependencies are critical to evaluating climate change impacts (Voisin et al. 2020). This study points to the importance of regional forces, beyond a single utilities' generation footprint or service area, in shaping grid and market conditions under drought and climate change. These forces and conditions can impact resource adequacy and risk as well as a utility's preferred resource portfolio in IRPs.

Decision-making under deep uncertainty (DMDU) is a framework for addressing climate uncertainties that has been used in the water industry. As the electric grid transitions to more weather-based renewable energy supply and as the impacts and uncertainty of climate change become more pronounced, the DMDU framework and principles may be increasingly relevant for electric utility IRPs to address the uncertainty associated with complex future regional climate projections.

The results of the assessments of climate change by utilities in IRPs illustrate the likelihood that if IRPs are not addressing climate change, they are introducing several potential sources of uncertainty and error. Namely, water availability can have impacts on the availability and the timing of generation. Changing temperatures can lead to changes in loads and in the demand-side resources predicated upon the timing and magnitude of loads. Changes in the overall generation resource mix, as well as loads, can impact wholesale power markets and wholesale prices as well as grid reliability. Interregional climate change impacts exist and can impact generating resource availability and market conditions. **Taken together, these represent cumulative areas of significant potential uncertainty and impact. New standard methods and tools may be needed in IRPs to properly plan and account for water and climate-based impacts to generation, loads, and markets.** Different approaches are needed for different areas and conditions. Regional and interregional modeling activities are needed that are accessible to electric utilities during integrated resource planning. Peer networks could help share challenges, approaches, solutions, and lessons learned and to speed implementation of new methods given the import of the issues and potential costs and consequences of delayed action.

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1.0 Introduction

Integrated resource planning (IRP) is the process by which a utility projects future customer needs and identifies the resource mix that is most likely to meet those needs while balancing cost and risk. Utilities generally perform IRPs every 2 to 3 years, and the analyses extend 10 to 20 years into the future. IRP brings together the consideration of customer demand for utility services, the supply and demand resources by which the demand can be met, and the environmental, legal, financial, and regulatory considerations that guide or constrain how the utility operates. It is a process for identifying risks and opportunities and for charting a course that takes into account the aforementioned considerations while addressing risks and taking advantage of opportunities.[1] As such, IRP is a key forward-looking process for addressing the environmental considerations that are the subject of this white paper.

One limitation of using IRPs for this review is the fact that IRPs are more common in vertically integrated states – those where a utility provides generation, transmission, and distribution services. In states that participate in regional markets operated by a Regional Transmission Operator (RTO) or Independent System Operator (ISO), on the other hand, transmission is performed by the market operator and distribution is performed by the utility, while responsibility for generation varies by region. Some states within regional markets have IRP requirement, such as California, Michigan, and Indiana. Other states, such as the states in New England, do not. However, while some gaps exist in coverage, IRPs offer a uniquely comprehensive, single window into utility planning so this review focuses on treatment of water resources and climate change in IRPs.

The environmental consideration that could become a constraint on future IRPs is the impact of climate change on surface and groundwater within the area in which the utility's generating resources are located, including both thermal resources and hydropower resources. Availability of water can impact the ability to cool thermal resources and generate power through hydroelectric generation. Insufficient incoming water can prevent thermal plants from being operated at full capacity, and if the situation becomes severe enough, it could prevent plants from operating at all. Likewise, changes to water availability, both timing of flows and quantity of water can impact hydropower generation. In thermal electric plants, if incoming water is too warm it can lead to additional costs to add additional cooling capacity, lead to a reduction in the net plant generating capability, and/or make it harder for plants to meet permit requirements related to water temperatures after cooling water is returned to the source of the water or otherwise discharged. Concurrently, the conditions leading to input water shortages or water temperature increases—conditions like higher average temperatures or prolonged drought—would likely lead to changes in consumer electric demand.

With hydroelectric generation, changes to water availability, both timing of flows and quantity of water can impact the total annual energy generation as well as when the energy is available which, in combination with potential load changes, poses challenges for utilities with significant hydroelectric resources. Highlighting these potential challenges is a significant non-IRP set of

[1] IRPs typically examine one to several primary cases, or resource portfolios, organized around specific themes, such as "100 percent carbon-neutral by 2035" or "technology agnostic" or other themes. To address risks or opportunities IRPs typically examine multiple alternative input cases in which key assumptions like future costs of renewable generation, future caps or taxes on emissions, fuel prices and other inputs are varied to determine how such would affect the results. Alternative cases can take the form of additional resource portfolios or sensitivity analyses performed using primary cases.

studies performed in accordance with Section 9505 of The SECURE Water Act of 2009 (U.S. Congress 2009) and referred to as "9505 assessments." The U.S. Department of Energy (DOE) working with the Oak Ridge National Laboratory, the U.S. Corps of Engineers, the U.S. Bureau of Reclamation, the International boundary Water Commission and the federal Power Marketing Administrations (PMAs) has performed two 9505 assessments of the potential future climate impacts on the federal hydropower resources, the output of which is marketed by the PMAs. (DOE is currently working to deliver the third assessment.) In a 2017 Report to Congress summarizing the second 9505 assessment, DOE stated "(t)he most important climate change effects impacting future hydropower generation are likely to be earlier snowmelt, change of runoff seasonality, and increasing frequency of extreme high- and low-runoff events." (U.S. DOE 2017)

The dependence on cooling water is changing, as discussed in sections 2.0 and 7.0, as utilities retire thermal generation and rely more heavily on non-carbon dioxide emitting resources. However, dependence on water will remain an important factor for hydroelectric generation, and for cooling nuclear plants, some large gas plants and any modern and efficient coal plants retained by utilities as they progress to lower-carbon dioxide emitting generating portfolios. This dependence is being increasingly complicated by the impacts of global climate change. As utilities experience and learn more about the potential impacts of climate change on the hydrological cycle and on customer loads, analyzing the impacts of water risks and climate change becomes increasingly important. The purpose of this white paper is to report on an investigation of the extent to which utility IRPs across the United States are addressing the impact of water availability, water temperature, and climate change impacts on the consideration and selection of resource portfolios.

2.0 Background

In 2015, water used for power plant cooling represented approximately 41% of total water withdrawals in the United States, including freshwater and saltwater withdrawals. Power plant cooling represented 48% of surface freshwater withdrawals. Electric utilities use cooling in thermal generating resources to condense the steam used to turn generators back into a liquid state. The major types of cooling are:

- Once-through cooling,[1] in which the utility withdraws water from a water source, discharges heat into the water, then discharges the now-warmer water back to the water source.
- Closed-loop or recirculating cooling, in which the water is in a loop in which it passes through the generator cooling system and is delivered to a cooling tower or a cooling pond to release the heat.
- Dry-cooling systems, which use air to cool the steam (UCS 2013).

The difference between the amount withdrawn and the amount returned is referred to as consumptive use. Consumptive use comes in the form of evaporation when heat is discharged in the cooling system (Dieter et al. 2018). Once-through cooling withdraws large amounts of water, but most cooling water is returned to the water source, though at a warmer temperature than it was withdrawn. Once-through cooling represents approximately 36% of thermal generating capacity in the United States (EIA 2018). Closed-loop systems withdraw significantly

[1] For each of the cooling types, a variety of different names are employed. For simplicity, the various names are not listed or used herein.

smaller quantities of water, but the proportional consumptive use is higher. In closed-loop systems, withdrawals are needed to make up for the consumptive water use, which comes in the form of evaporation in the cooling tower or from the surface of the cooling pond, blowdown,[1] drift,[2] and leakage (Dieter et al. 2018). Closed-loop cooling represents approximately 61% of U.S. thermal generating capacity (EIA 2018). On average, closed-loop cooling has a 1.2% energy penalty compared to once-through cooling (McCall et al. 2016).

Dry-cooling uses little or no water for the cooling. Dry-cooling is most commonly used with natural gas generation, with natural gas representing 83% of the capacity that is either dry-cooled or a hybrid of dry-cooled and water-cooled. Dry-cooling uses about 95% less water than water-cooling, but the tradeoff for dry-cooling is a higher cost and lower efficiency (EIA 2018). Dry-cooling costs 1.5 to 8 times as much as water-cooled systems and reduces the efficiency of the generator by 2% to 3% in moderate climates and up to 10% in hot climates (McCall et al. 2016).

In the United States, thermal power plant cooling is the largest single withdrawer of water (Dieter et al. 2018). A summary graphic from this report, created for the United States Geological Survey (USGS), is shown below in Figure 2-1.

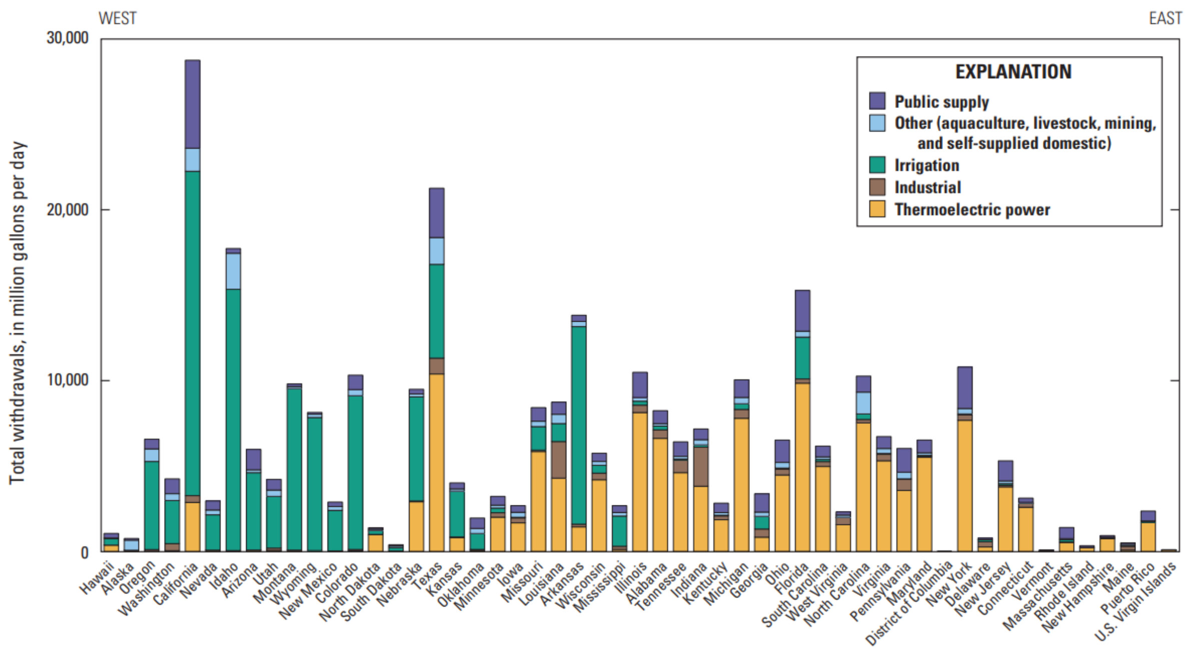

Figure 2-1. Major Water Uses, by State (Dieter et al. 2018)

According to the USGS data, the total withdrawals for thermoelectric power production have declined. A second figure from the USGS shows that withdrawals have declined from 201 billion gallons per day in 2005 to 133 billion gallons per day in 2015 (Dieter et al. 2018). The USGS attributes these changes to a number of factors, including increasing numbers of thermal plants switching from once-through cooling to closed-loop cooling (discussed immediately following Figure 2-2); an increasing reliance on natural gas-fired generation, which tends to use either

[1] With water recirculated through the process impurities are concentrated in the water, some of which is removed from the loop to protect the equipment.

[2] Drift is water lost from the cooling tower through droplets of water carried away in the air leaving the cooling tower (FEMP, 2011).

closed-loop or dry cooling (discussed immediately following Figure 2-2); and the retirement of coal plants, including plants using once-through cooling (Dieter et al. 2018). While there is a significant downward trend shown in Figure 2-2, water used in electric generation remains the largest single reason for water withdrawals and represented 41% of total diversions as noted above in the most recently available data. It is likely the trends shown in Figure 2-2 continue to the present as additional coal plants have been retired since 2015 and low-water using renewable resources have become more prevalent. This issue is discussed further in Other Issues, Section 7.0.

It should be noted that a significant amount of water is withdrawn for cooling, but the majority of the water is returned to the water source, albeit at a warmer temperature. Of the total water diversions, approximately 3% of the water is consumed and not returned. The difference between the amount withdrawn and the amount returned is referred to as consumptive use. Consumptive use comes in the form of evaporation when heat is discharged in the cooling system (Dieter et al. 2018). While the percentage of withdrawals that is consumed is small, the result is still a significant amount of water. In 2015, estimated total water diversions were 133 billion gallons per day while consumption was 4 billion gallons per day (Dieter et al. 2018).

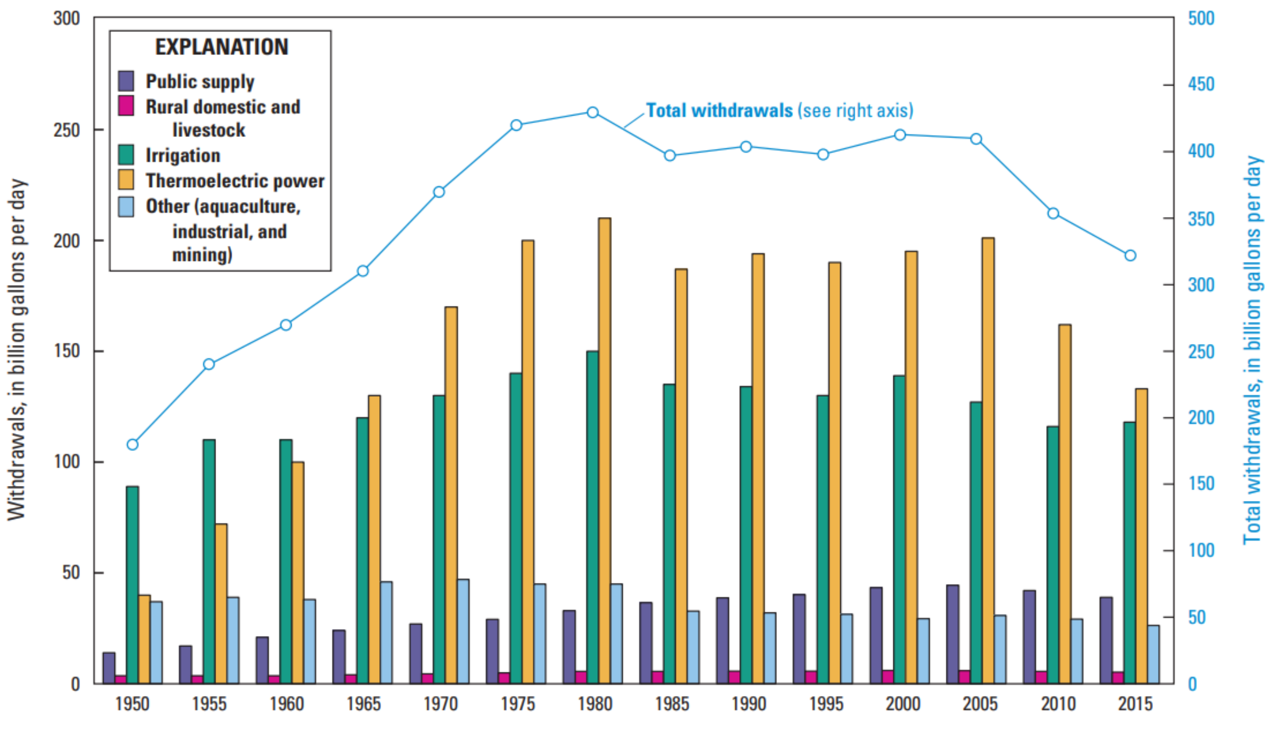

Figure 16. Trends in total water withdrawals by water-use category, 1950–2015.

Figure 2-2. Trends in Water Withdrawals, Total for United States (Dieter et al. 2018)

Drought and other climate-related issues can impact generators that rely on water for cooling. First, if drought reduces the available water to such an extent that a generating plant cannot obtain sufficient cooling water, generation at the plant might need to either curtail output or shut down entirely. Second, the efficacy of cooling is dependent in part on incoming water temperature. If incoming water is warmer than normal, efficiency can be reduced, leading to a potential reduction in maximum generating capacity, and possibly to a shutdown. Third, if the temperature of post-cooling discharge water exceeds limits specified in the plant's permits under the Clean Water Act, this can lead to permit violations and potentially cause the plant to curtail production or to shut down entirely (McCall et al. 2016).

In the McCall et al. (2016) report published by the National Renewable Energy Laboratory (NREL), researchers collected data from numerous sources on water-related issues at coal-fired and nuclear generating facilities. NREL utilized two data sets and identified power plants that experienced water shortfalls and/or had water temperature violations. NREL identified 43 incidents that took place between 2001 and 2015 that were documented in reports, the press, and press releases. These included 18 incidents that involved coal plants and 25 that involved nuclear plants. The incidents involved a lack of intake water, or either the intake or the discharge water were too warm. In some cases, both intake and discharge were too warm. Roughly half of the incidents involved discharge water that was too warm. Seven cases involved insufficient intake water (McCall et al. 2016). NREL also identified five cases in which plants were at risk, but no incidents had occurred (McCall et al. 2016). Figure 2-3 shows the location of plants identified by NREL in their study.

As can be seen in Figure 2-3, NREL identified one hydroelectric facility, the Hoover Dam, that experienced intake water insufficiency. In 2014, Hoover Dam operators reduced power production due to the results of an extended drought (McCall et al., 2016). In July 2014, Lake Mead water fell to a lake elevation of 1,075.08 feet, barely above the 1,075-foot elevation that would have triggered a lower Colorado River water shortage declaration—the first such declaration (Kennedy 2015). At that time, the Colorado River Basin was in the fourteenth year of a drought that started in 2000 and is ongoing as of this date. Between 1999 and 2015, the Lake Mead water elevation dropped from 1,196 to 1,075 feet. At a surface elevation of approximately 950 feet, the dam will no longer be able to generate electricity (Walton 2016).

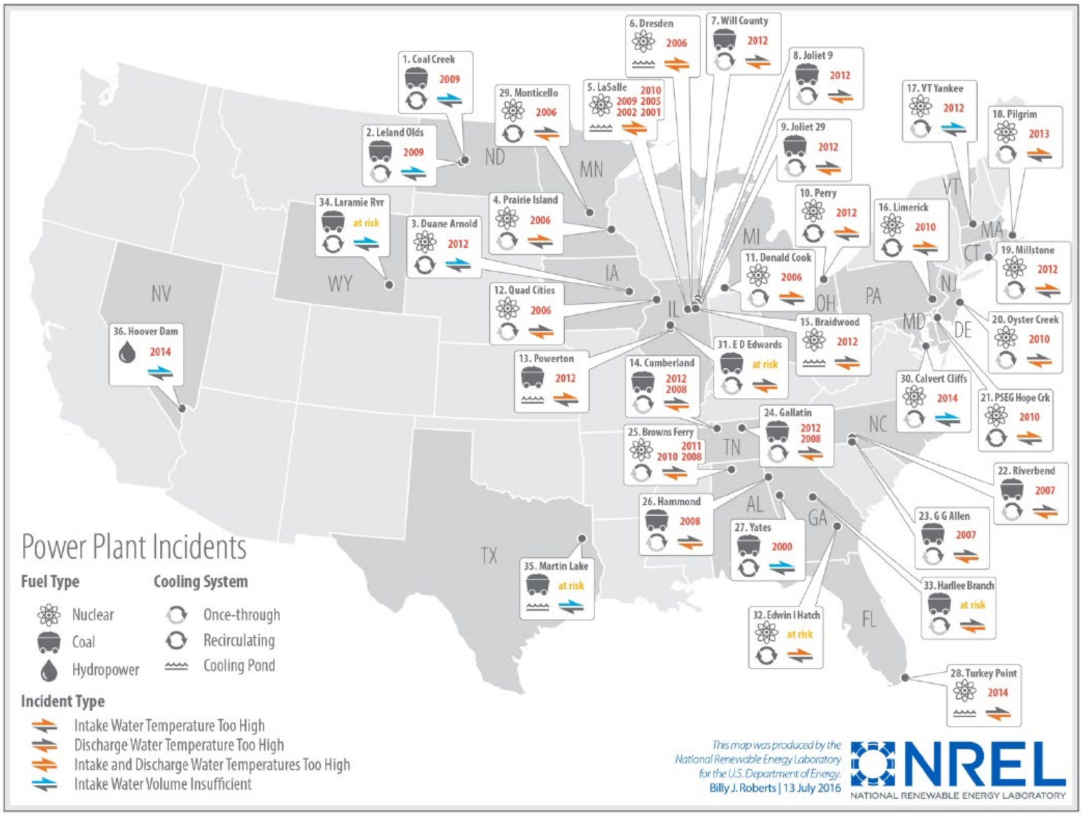

Figure 2-3. Power Plant Cooling Incidents between 2000 and 2015 (McCall et al. 2016)

The U.S. Bureau of Reclamation recently projected the Lake Mead water level might fall below 1,075 feet in 2021. If Lake Mead levels fall to levels that cause generation curtailments or cessation, the lost generation will lead to tighter power markets and will have a large impact on consumer-owned utilities in the region that heavily rely on power output from Lake Mead (Metz 2021). Note also that the Colorado River is not the only western river system facing water shortages in 2021. In California, the Bureau of Reclamation has indicated that operations on the Sacramento River at the Shasta Dam will be adjusted to benefit Chinook salmon. The adjustments include a reduction in generation at the dam to preserve cold water at the bottom of the reservoir to benefit salmon (U.S. Bureau of Reclamation 2021a). At the California – Oregon border, the U.S. Bureau of Reclamation's Klamath Project also announced significant changes to operations to maintain water in the river for endangered fish (U.S. Bureau of Reclamation 2021b). In the case of the Klamath Project, the changes affect the water delivered to irrigators but not electric customers, as the project does not include hydroelectric generators.

The aforementioned NREL study identified a second set of power plants with water-related concerns through an analysis of the U.S. Environmental Protection Agency (EPA) Enforcement and Compliance History Online (ECHO) database that tracks compliance and enforcement information for facilities that fall under EPA regulations (EPA 2020a). NREL identified 35 incidents in which discharge water temperature exceeded permit levels between 2012 and 2015. These incidents are in addition to the other 43 incidents identified, as there was no overlap between the datasets. The 35 incidents included other forms of thermal generation in addition to coal and nuclear plant (McCall et al. 2016). NREL's map providing the location of violations is shown in Figure 2-4.

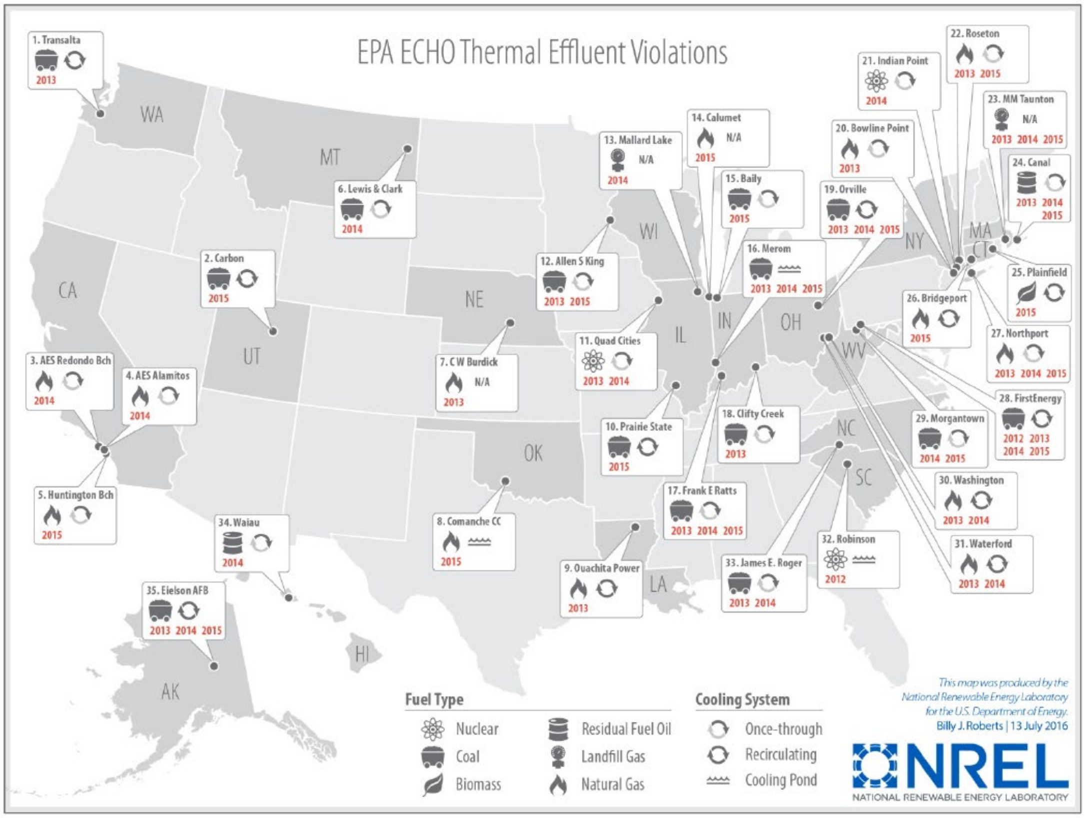

Figure 2-4. EPA ECHO Thermal Effluent Violations Between 2012 and 2015 (McCall et al. 2016)

S&P Global Market Intelligence recently reported on a study looking at the potential impact of climate change on U.S. coal plant operations. For the year 2030, the study identified 98.2 gigawatts (GW) of coal capacity at risk due to water stress, with just under 45% of this capacity located in five states—Texas, Indiana, Illinois, Wyoming, and Michigan (Kuykendall and Whieldon 2020). The report also noted that 62% of the 25.1 GW of coal generation that has regulatory approval to retire is in areas projected to face water stress in 2030 (Kuykendall and Whieldon 2020). Figure 2-5 shows the S&P map.

Figure 2-5 is extracted from a S&P Global Market Intelligence report entitled Rising Water Stress Risk Threatens U.S. Coal Plants, Largely Clustered in 5 States, written by Taylor Kuykendall and Esther Whieldon, copyright[1] date October 22, 2020. It is used with permission of S&P Global Market Intelligence.

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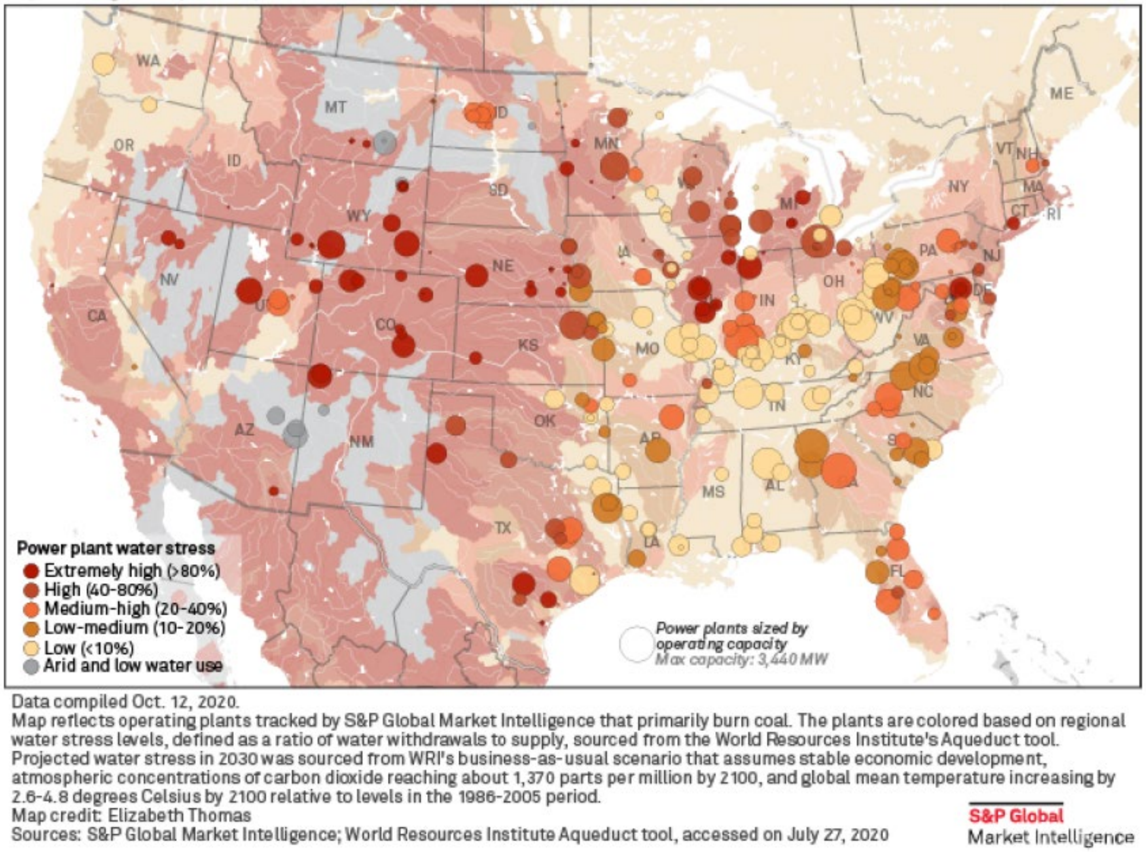

Figure 2-5. Coal Power Generation in Areas Expected to Experience Water Stress in 2030 (Kuykendall and Whieldon 2020)

3.0 Extent to which IRPs include water constraints

This white paper's main purpose is to examine the extent to which utility IRPs examine the impact of water constraints on resource portfolios (and document such in their IRPs). The white paper divides the discussion by looking at how water constraints affecting thermal generation and water constraints affecting hydroelectric generation are addressed. As noted in Section 2.0, some thermal generating stations have experienced constraints due to a lack of cooling water or because water temperatures were too high. This white paper documents a review to identify IRP best practices for addressing such constraints. Similarly, for hydroelectric generation, this white paper reviews how IRPs treat uncertainties surrounding water availability for generation. For both thermal generation and hydroelectric generation, the white paper examines if or how the IRPs are attempting to quantify potential impacts of future climate change.

It should be noted that in researching this white paper we did not attempt to compile statistics.[1] Rather, the intent was to identify what is contained in IRPs and identify best practices related to the following questions:

1. Are utilities identifying water constraints (availability or quantity, temperature, cost) as issues in their IRP? How is this manifesting itself in the IRP?

[1] The authors have, in other reviews of IRPs, developed statistics on IPRs falling within categories such as those shown on Table 3-1. This was not done herein.

2. Do IRPs include any water metrics in the metrics used to choose between resource portfolios? Is water usage quantified as an outcome in the IRP?
3. Are utilities treating water constraints as variable in their IRP, and how is this treatment being reflected?
4. Are utilities including climate change as a primary or alternative analysis case? Are IRPs addressing climate change in any way that could be identified?

The questions are not equally applicable to thermal and hydroelectric generation, but where a question might not be applicable, such is noted.

To start this examination, internet searches were performed to link the keyword IRP with keywords like water, water resiliency, and climate change. The internet searches identified three IRPs that appeared relevant—Arizona Public Service (APS), Tennessee Valley Authority (TVA), and Memphis Light, Gas, and Water (MLGW). The internet search results included too much noise to be particularly helpful beyond identifying the aforementioned three IRPs. The next step was to focus examination on regions of the country with known water issues, such as Arizona; areas identified in the S&P/Kuykendall paper where water stress is expected for coal plants; and other areas of the country where IRPs are required, including the Pacific Northwest, the Southwest and Rocky Mountain states, the Midwest, and the Southeast. A list of the IRPs discussed herein is included in Table 3-1.

In reviewing IRPs for this white paper, we searched for references to water, cooling, withdrawals, gal, curtail, derate, resilience, climate, heating, and other keywords. Some IRPs are as short as 150 pages (e.g., the publicly available version of the Georgia Power 2019 IRP, which is available online as a Word document of 147 pages; Georgia Power 2019). Duke Energy Carolinas' 2020 IRP is 406 pages, which might be typical (DEC 2020). Others can be much longer. The three volumes of the PacifiCorp 2019 IRP total 954 pages (PacifiCorp 2019).

Table 3-1. Utilities with IRPs That Address Water

Utility / Entity	Year of IRP	Includes Water Metric	Includes Water Reduction Goals	Includes Water Plan	Includes Plant Water Usage	Includes Only CWA Issues	Included Water in Scenario Analysis	Included Some Climate Change Impacts
Ameren	2020					Yes	*	
Arizona Public Service	2020	Yes	Yes	Yes	Yes±			
BC Hydro							Yes	Yes
Dominion Energy, dba VEPCO	2020	±±				Yes		
Duke Energy, Carolinas	2020			**		Yes		
Duke Energy, Indiana	2018				Yes±			
Georgia Power	2019					Yes		
Idaho Power	2019						Yes	Yes

Utility / Entity	Year of IRP	Includes Water Metric	Includes Water Reduction Goals	Includes Water Plan	Includes Plant Water Usage	Includes Only CWA Issues	Included Water in Scenario Analysis	Included Some Climate Change Impacts
Memphis Light, Gas, and Water	2020	Yes						
Northwest Power and Conservation Council	2016						Yes	Yes
Northwestern Energy	2019				Yes[±±±]		Yes	
PacifiCorp	2019				Yes[±±±]		Yes	
Portland General Electric	2019				Yes[±±±]		Yes	
Puget Sound Energy	2021							Yes
Seattle City Light	2016						Yes	Yes
Southwestern Public Service	2019				Yes[±±±]		Yes	
Tacoma Power	2020						Yes	Yes
Tennessee Valley Authority	2019	Yes		**			Yes	Yes
Vectren, Indiana	2019					Yes		Yes
Xcel Upper Midwest	2020					Yes		

* Ameren commissioned a consultant report to identify tools for studying future climate change impacts. The tools were not used in this IRP.
**A separate sustainability report provides insight into water management for purposes of maintaining or improving water quality, for purposes of reducing water consumption in buildings occupied by the utility and provides information about total utility water withdrawals and consumptive uses for a historical period.
[±] At a minimum, the IRP provides estimates of the total water usage for the primary resource portfolio, either by year, or for selected future years.
[±±]The Virginia Electric Power Company (VEPCO) IRP includes statements about using less water through use of air-cooled condensers and that changes in the generation mix have reduced the amount of water used. The publicly available IRP provides no further information on the quantification.
[±±±]The IRP provides estimates of the water usage per MWh for each generating facility. The Portland General Electric and Northwestern Energy Montana plans both include consultant reports assessing new supply-side resources and which include estimates of water usage per unit of production. Northwestern also owns approximately 500 MW of hydroelectric generation, and the IRP says they use hydrological data in the stochastic analysis, but details were not identifiable in the IRP.

Where initial searches turned up nothing that was applicable (and where a test indicated the IRP had not been saved in a non-searchable format), the IRP was not reviewed further. IRPs that were searched but not discussed further are listed in Table 3-3.

Some IRPs offered interesting ideas related to water, but that are not specifically on point (e.g., Duke Energy Carolinas (DEC) noted that when a coal plant is retired, the water infrastructure is in place, making a brown field replacement project perhaps more attractive than a green field project that needs to make such investments [DEC 2020]). The Lafayette 2020 IRP included significant details on the engineering of water uses within the generating facilities. While this is interesting from the perspective of understanding water usage, the IRP did not report on the types of metrics or analyses sought for this white paper. These were noted but are not within the scope of this paper.

Table 3-2. Other IRPs Scanned during White Paper Research

Utility	Year of IRP
Alabama Power	2019
Entergy Arkansas	2018
Illinois Power Agency	2018 Draft Electricity Procurement Plan[1]
Indiana Municipal Power Agency	2017
Great River Energy	2018 – 2032
Lafayette (LA) Utilities System	2020
Lansing (MI) Board of Water & Light	2020
Minnkota Power	2019
Nebraska Public Power District	2018
Springfield (Illinois) City Water, Light and Power	2019

4.0 Best Practices for Addressing Water for Power Plant Cooling in IRPs

Water is used widely to cool thermal power plants in the United States, and, as already noted, drought and other water constraints can disrupt the normal use of power plants. Because of these facts, a main focus of this white paper was to review how utilities treat water in their IRPs. This section discusses the IRP review focusing on the research questions identified in Section 3.0.

1. Does the IRP mention water as a constraint and how does the IRP deal with the constraint?

2. Is water used as a metric in decision-making?

3. If water is considered, how is it considered in decision-making?

4. Are utilities including climate change as a primary or alternative analysis case?

Utility IRPs are processes undertaken to identify future resource portfolios to meet customer capacity and energy needs while balancing the costs and risks of the future resource portfolios. IRPs involve projections of innumerable variables and constraints. Some variables and constraints involve sufficient levels of uncertainty and have sufficiently significant impacts on the outcome of the IRP that they are studied with alternative sensitivity analyses and/or assigned probability distributions and varied within the main analysis cases. IRPs treat other variables

[1] The procurement plan is not an IRP. It is a type of plan found in many deregulated states to address the question of whether sufficient resources will be available to meet retail customer needs.

more as known values or constants. Thus, a focus of this white paper was to identify whether water is considered to be a variable with a potentially significant impact on the IRP or treated as a known value.

4.1 Is Water Treated as a Constraint and Addressed by the IRP?

The first issue asked whether utilities are identifying water constraints (availability, quantity, temperature, cost) as issues in their IRP, and how this information manifests in the IRP.

4.1.1 Clean Water Act-Related Water Intake and Disposal Costs

Compliance with Clean Water Act (CWA) requirements comprises a part of the capital costs utilities identify and include in IRP model runs. The two key areas of Clean Water Act compliance have to do with water intake and waste product disposal. Each are addressed below.

- Water Intake: Although the Clean Water Act passed in 1972, the EPA did not finalize regulations related to the diversion of water until relatively recently (2014). As a result, many utility IRPs are still including future costs expected to be incurred by thermal plants to comply with the regulations. For example, Vectren's IRP deals with three existing coal plants. For one coal plant, Vectren has submitted information to state regulators; the state determined that the existing cooling structure meets the requirement to use Best Technology Available or BTA. For the second plant, Vectren estimated costs based on installing "standard fine mesh and fish friendly screens and fish return systems." For the third coal plant Vectren estimated costs based on their share of installing "modified travelling screens and a fish handling and return system" (Vectren 2020). Thus, in Vectren's case, costs for meeting the Clean Water Act at two coal plants are included in IRP analyses.

- Waste product disposal: The costs related to dealing with coal ash and other coal plant waste products are included in the IRPs of utilities operating coal plants. However, because the final rule in EPA's Steam Electric Reconsideration Rule (see EPA 2020b) had not been issued when many IRPs were developed, many outlined their expectations along with a caveat that the exact requirements were to be determined. Thus, utilities are driven by the need to address the EPA's 2015 Effluent Limitations Guidelines (ELGs) rule, even though the utilities did not know how the Reconsideration Rule would impact requirements as they were preparing the IRP. Using Vectren as an example, Volume 1 of Vectren's IRP includes discussions of meeting the ELGs related to ash handling, dealing with ash ponds and preventing said ponds from affecting groundwater and surface water quality, dealing with flue gas desulfurization products, and wastewater treatment to meet effluent limits for water flowing into waterways. (Vectren 2020) Vectren did not include a caveat about the Reconsideration Rule, but they did include a "low regulatory" scenario in their analyses (Vectren 2020).

For many IRPs reviewed for this white paper, costs related to the Clean Water Act are the only easily identifiable way that water is reflected in the IRP's treatment of thermal resources. As discussed in Section 7.5, most, if not all, IRPs reviewed herein include plans to eliminate all coal-fired generation from their resource portfolio. It is not clear the extent to which Clean Water Act compliance costs contribute to this process, but as a component of the cost structure for coal-fired generation, it would be a contributing factor whenever the decision is purely an economic decision. For example, Northwestern Energy, shown in Table 3-1 with an IRP for

Montana in 2019, also issued an IRP for South Dakota in 2020, and in that IRP they plan to retire older thermal resources that are seldom selected for dispatch in the Southwest Power Pool economic dispatch (Northwestern Energy 2020). In a review of the remaining 2020 IRPs, most IRPs are targeting either zero-greenhouse gas (GHG) emitting resources or GHG-neutral resources at least in part in response to state administrative rules or legislation. While Clean Water Act costs may contribute to the cost structure used to select the most economical date for retirement, it appears GHG-minimization is the main factor.

4.1.2 IRPs that Tackle Thermal Water Constraints Directly

The first research question asks whether IRPs mention water as a constraint and how the IRP deals with the constraint. Three IRPs tackle this directly. Best practice includes the inclusion of a water availability and conservation plan in the report, as well as performing scenario analyses to identify the sensitivities and impact intensity of water constraints on thermal generation and, in the case of one utility, to inform resource decision making. Additionally, two IRPs address water constraints by adjusting the rated capacity of generation, but do not appear to perform analyses of the impact of water availability beyond the adjustment to capacity.

4.1.2.1 Water Availability and Conservation Plan

APS included a plant by plant overview of the steps they are taking to assure reliability of water supplies. Of all the IRPs reviewed, the APS IRP contains the most complete documentation of how they intend to ensure sufficient water for their thermal plants as well as how they intend to ensure future sufficiency (APS 2020). APS identified strategies such as ending reliance on groundwater and using reclaimed water to secure a reliable future source. APS also stated goals for reducing water usage in their IRP.

4.1.2.2 Scenario Analysis of Water-Related Thermal Resource Constraints

Southwestern Public Service's (SPS's) 2018 IRP was the only IRP identified that included a scenario analysis to address water constraints on a thermal resource. SPS's Tolk Plant relies on groundwater for cooling. Depletion of the aquifer has been accelerated by drought and by agricultural irrigation, and SPS found that they must add new wells each year at a considerable expense and with diminishing returns (SPS 2018). SPS ran seven different cases to examine the best way to deal with the Tolk Plant water issues, selecting a case in which the plant continues using groundwater, but operates only in the summer as a peaking unit. Because water usage is a direct function of generation, limiting generation only to the summer peak season enables SPS to stretch the useful life out (relative to the useful life they might be able to achieve in business as usual operations, which would deplete the aquifer more rapidly). SPS will also retire the plant prematurely, closing it in 2032 (SPS 2018).

4.1.2.3 Adjusting Capacity Values for Water Constraints

Xcel Upper Midwest's (Xcel's) 2020 IRP and Vectren's 2020 IRP both address the question of the impact of water constraints on capacity by pointing to the difference between a plant's rated, installed capacity, and the measure of capacity used in their analyses that takes into account the plant's forced outage rate. Both IRPs use a measure of capacity that explicitly reduces the rated capacity by the amount of the time that the equipment is unavailable due to forced outages and maintenance. Using this measure of capacity is common. See, for example, PacifiCorp 2019 or NWPCC 2016. However, Xcel and Vectren were explicitly responding to requirements to account for either water constraints or water temperature on plant availability.

Xcel was addressing regulatory commission requirements (Xcel Upper Midwest 2020, Appendix F2), while Vectren was addressing a reliability organization requirement (Vectren 2020, Vol. 2 of 2).

Xcel and Vectren both adjusted the installed capacity to account for outages over some recent historical period. Thus, if water issues have already affected the availability of the plant they would be accounted for in the adjusted capacity values used in the IRPs. While such is a common practice and might be a best practice, it looks back insofar as it is an adjustment based on historical issues and tells nothing about the potential for issues in the future. It was noted in the cases of Vectren and Xcel Upper Midwest because they explicitly used the metric as a mechanism to address water constraint impacts.

4.2 Water Metrics Used

This white paper also looks at whether water usage was used as a metric in the decision-making process for selecting preferred resource portfolios, and if so, how this was included.

Three utilities included water metrics as part of their metrics for selecting preferred portfolios. APS 2020, TVA 2019, and MLGW 2020 all included water consumption as a metric in their decision-making. MLGW included it as one of three components of a sustainability metric (MLGW 2020). APS included water use in 2035 as a metric (APS 2020). TVA 2019 included water usage as one of a number of metrics used to evaluate portfolios (TVA 2019). None of the three IRPs provided information as to how the metrics were specifically weighted into the selection of portfolios.

4.3 Water as a Variable in IRPs

When the research for this white paper began, it was expected that IRPs would view water constraints as issues to be studied in the stochastic analysis. As discussed in Section 4.1.2.2, utilities with a heavy reliance on hydroelectric resources do perform such stochastic analyses in which resource availability under differing water conditions is studied. The TVA and SPS IRPs noted in Section 4.1.2.2 were the only IRPs that documented scenario analyses that specifically addressed non-hydropower water issues in scenario analyses.

4.4 Modeling Climate Change Impact on Thermal Resources

TVA was the only IRP identified that performed a climate sensitivity case (that was clearly documented and identified) to explicitly study the impact on cooling capacity at thermal plants in a climate change case (TVA 2019). TVA's IRP noted that they have derated individual plants in the past and invested in additional cooling at others because of water temperature issues (see TVA 2019, Vol. II, p. F-88). In their case, TVA identified possible summer capacity derating of coal and nuclear plants in response to hotter, dryer summers, with changes in the resource portfolio (more solar, earlier installation of combustion turbines) to compensate for the reduced capacity (TVA 2019).

5.0 Best Practices for Addressing Water Constraints on Hydroelectric Generation in IRPs

This section discusses three of the research questions spelled out in Section 3.0 and the introduction to Section 4.0 with respect to water used in hydroelectric generation. Because utilities with significant hydroelectric resources have performed significant analyses of the potential impacts of climate change, this is presented separately in Section 6.0.

In many IRPs reviewed, hydroelectric resources represent a small percentage of the total resource portfolio. Vectren and SPS did not show any hydroelectric resources in their existing supply portfolios (Vectren 2020; SPS 2018). For Duke Energy, Indiana, hydroelectric resources represented under 1% of their existing resource mix (DEI 2018). In addition, 1% of Dominion Energy's existing resource mix (Dominion Energy 2020), 2% of Georgia Power's existing resource mix (Georgia Power 2020) and 5% of Xcel Upper Midwest's existing resource mix (Xcel Upper Midwest 2020) were hydroelectric resources. For the IRPs with relatively small amounts of hydroelectric generation in the resource portfolio, the discussion of hydroelectric was minimal, with no indication that the IRP treated water as variable.

5.1 Is Water Treated as a Constraint and Addressed by the IRP?

With some similarities to those utilities who consider water constraints for thermal plant cooling, the best practices include (1) the inclusion of water availability through resource adequacy testing, and (2) performing scenario analyses to identify future water availability and sensitivities, and to use water constraints as a tool to inform resource decision-making.

5.1.1 Water Availability and Hydroelectric Resource Adequacy Testing

A resource adequacy standard tests whether a utility has enough generation resources to meet forecast load. While all utilities analyze resource adequacy, only the utilities with significant hydroelectric resources consider water availability as a variable in the analysis. Many utilities in the Pacific Northwest have historically used critical water planning to evaluate the resource adequacy of the utility's resource portfolio. Critical water is defined as the historical year in which runoff was the lowest leading to the lowest hydropower capability in the peak winter months (NWPCC 2016). Given that the Pacific Northwest utilities in some cases have 70 or more years of hydrological data, the critical water benchmark represents a level of hydroelectric generation that the hydroelectric facilities should meet or exceed with a high likelihood. However, while setting a benchmark the utility can plan on in essentially all cases it also causes the utilities to (potentially) acquire more resources that necessary at a greater system cost than necessary. Thus, in an attempt to balance the need to maximize the likelihood of the hydroelectric output being sufficient when combined with the utility's other resources while attempting to reduce the likelihood of incurring the costs of acquiring more resources than necessary, utilities employ probabilistic adequacy metrics to quantify water availability uncertainties.

Tacoma Power's IRP used a probabilistic approach to test their resource adequacy against three dimensions: magnitude standard, duration standard, and frequency standard. Tacoma Power's stochastic analysis used 58 weather years combining inflow conditions for the hydroelectric generation facilities and temperatures seen in historic years. The stochastic analysis also included variability in natural gas prices. In total, Tacoma Power ran 1,160 simulations for portfolio cost and risk, and 232 simulations to analyze resource adequacy. If a portfolio met the standards of (1) annual expected capacity shortage of no more than 0.001% of load per year, (2) no more than 2.4 hours of capacity shortage per year,[1] and (3) no more than two days with a capacity shortage of any magnitude or duration every ten years, it was considered adequate (Tacoma Power 2020). Tacoma Power 2020 also included climate change analyses, which are discussed in Section 6.0.

Idaho Power, another Pacific Northwest utility with significant hydroelectric resources, also used monthly hydroelectric production projections based on a probabilistic analysis of water availability data in their 2019 IRP. Idaho Power made explicit adjustments to water availability estimates to reflect potential changes to the flows into their Snake River system dams from water management practices in Idaho, including aquifer recharge and groundwater to surface water conversions. They also took into account statistically significant declines in water flows between 1988 and 2017 in specific portions of the Snake River system. Using historical data and the projected changes, Idaho Power modeled the system and developed projections for use in the IRP reflecting 50th percentile generating output (the mid-point in the generation curve), 70th percentile output (generation meets or exceeds this level 70% of the time), and 90th percentile output. With loads, hydroelectric generation, and other resources allowed to vary in the model used by Idaho Power (AURORA), the selected portfolio was analyzed for 100 iterations for the year 2025 to study the risk of loss-of-load events, with the result found to be within the one event per 10 years adequacy standard used widely in the U.S. power industry (Idaho Power 2020).

Portland General Electric (PGE), another Northwest utility, similarly included three forecasts of hydroelectric generation in their analyses. The analysis looks at 270 futures under 810 future conditions, with one of the sets of parameters that vary being hydroelectric generation. PGE used a reference case and ±10% (approximately one standard deviation) projections of hydroelectric output. PGE used a capacity adequacy metric of no more than 2.4 hours of lost load every year, or one day in 10 years (PGE 2019).

The Northwest Power and Conservation Council (NWPCC or Council) develops a regional power plan to balance the Northwest's environment and energy needs. For their 7th Power Plan, the NWPCC performed a 20-year analysis, making use of the 80-year historical record of inflows in the Pacific Northwest hydroelectric system. In the modeling, the NWPCC allowed hydroelectric generation, loads, and generation availability to vary and identified future years in which shortages were identified in one or more hours. The NWPCC ran 800 simulations of the model. For each simulation, to model water availability, the NWPCC's model randomly picked a historical water year to use as a starting point, then moved sequentially through the water years to complete the 20-year run. To identify resource shortages/needs, the NWPCC looked five years into the future. If in any hour of the five-year period the models identified a shortage in the available resources, the shortages were then screened against available standby generation. If the shortages exceeded the energy/capacity of standby units, the shortages were considered curtailment events. Note that the shortages could be either energy, capacity, or both. The NWPCC used a loss-of-load probability (LOLP) adequacy metric. To determine whether a portfolio was adequate, the NWPCC applied a 5% LOLP criteria, meaning a portfolio was considered to be adequate if there was no more than a 5% likelihood that an energy or capacity shortfall would occur at any time in any future year (NWPCC 2016).

The NWPCC's 2021 Power Plan (in preparation) is using forward-looking climate data based on downscaled data from global climate models. The downscaling is discussed in Section 6.1. The

[1] Equivalent to one day every 10 years.

NWPCC's ongoing work is utilizing climate change impacts developed on behalf of the Bonneville Power Administration, the U.S. Army Corps of Engineers, and the Bureau of Reclamation (collectively the River Management Joint Operating Committee, or RMJOC). The NWPCC uses the Generation Evaluation System (GENESYS) model, a Monte-Carlo computer program developed by the NWPCC to perform chronological hourly simulations of the Pacific Northwest power system for one operating year (October through September; 8760 hours) (NWPCC 2016). For the 2021 Power Plan, the GENESYS uses forward-looking weather and streamflow data based on a "business as usual" greenhouse gas future case (RCP8.5 – see Section 6.1) for three of the climate change cases developed by/for the RMJOC (Fazio 2021).

5.1.2 Scenario Analysis of Water-Related Hydroelectric Resource Constraints

Scenario analysis of water constraints can benefit forecasting of hydroelectric resource reliability and availability over the IRP planning period. Several utilities with significant hydroelectric resources studied water constraints as part of scenario analyses in their IRPs. For example, Tacoma Power's IRP uses an in-house system analysis model to model hourly generation depending on inflows, loads, future scenarios, and energy prices. The model's constraints include target water elevation levels, maximum discharge, and amount of operating reserves the utility needs to carry. Tacoma Power analyzed whether they might benefit from changing their purchases from the Bonneville Power Administration (BPA). Under the current BPA contract, Tacoma Power purchased the BPA Slice/Block product. In the "slice" part of the contract, Tacoma Power receives a fixed percentage of the actual output of the BPA power system, which, due to streamflow variations, will vary by year and season. The "block" portion is a constant amount of energy. The alternative studied was a Block with Shaping Capacity (a.k.a., Shapeable Block) product. A Block with Shaping Capacity product was modeled as a more flexible product than the block portion of the currently purchased BPA product. In the model, Tacoma Power shaped the BPA resource using historical weather-normalized retail loads. The IRP analyzed this choice and found that the least cost option would be to remain with the current product, with demand response capacity additions of 10 MW to temper adequacy risk of extreme low water conditions (Tacoma Power 2020).

Idaho Power uses the Snake River Planning Model to determine surface water flows, and the Enhanced Snake Plain Aquifer Model to determine the effect of various aquifer management practices on water availability. Using the combination of these two models, Idaho Power's IRP deployed an internal model to calculate a hydroelectric generation forecast. Idaho Power's IRP questioned whether water resource adequacy would result in a hydroelectric capacity adjustment during the planning period. The IRP did not find a compelling reason to alter their resource portfolio because of inadequate water availability. Idaho Power also modeled a climate change scenario and found there was still adequate supply for future demand scenarios (Idaho Power 2020).

6.0 Addressing Climate Change in IRPs

This section discusses how utility IRPs are addressing climate change. The white paper breaks this into three pieces: climate change impacts on thermal generation, on hydroelectric generation, and on load forecasting. Addressing climate change is a data-intensive process and one that introduces a great deal of uncertainty. Thus, before discussing how utilities have addressed climate change in IRPs, this section begins with a discussion of climate change data and of an emerging tool set used by water utilities to address future uncertainties. The remainder of this section discusses the extent to which electric utility IRPs and/or IRP processes (for IRPs still in draft stages) have included climate change analyses.

6.1 Climate Change Data Development

Addressing climate change can introduce a significant level of complexity to the IRP process. The climate change modeling tends to be performed at global scales using global climate models (GCMs) and include multiple scenarios of future concentrations of atmospheric greenhouse gasses with the modeling performed using several models that produce different results. To utilize the global modeling results, a utility with a service territory located in one (or more) state(s) must downscale the global models to their specific service territory and to the geographic areas that impact their service territory. For a utility with a hydroelectric facility, the analysis necessarily would include the geographic area comprising the watershed of the river on which the hydroelectric facility is located.

As an alternative to addressing the data reconciliation and uncertainties surrounding global modeling, electric utilities have investigated modifications to the way they utilize historical data to attempt to capture the changes included in the data. For example, the Puget Sound Energy (PSE) 2021 IRP base-case electric and natural gas load forecasts were based on "normal weather," which was defined as average monthly weather over a 30-year period (PSE 2021). Because PSE had committed to examining a future temperature sensitivity analysis, they investigated alternative analyses of the historical data and an analysis of global climate change models. In their stakeholder process, they presented three options. The first was a redefinition of the "normal weather" period to include only the most recent 15 years. The second was historical trended temperatures. The IRP includes a consultant report (Appendix L) that presents the results of regression analyses performed to identify trends in the historical data of temperature, resulting in projections of cooling degree days that increase and heating degree days that decrease over time. The third alternative was to use the NWPCC climate model (discussed below). In the stakeholder process, PSE asked stakeholders to select one option; the stakeholders selected the NWPCC model (PSE 2021).

In the Pacific Northwest (including British Columbia, Canada), electric utilities have been developing climate change data over a decade based on global climate change models. The RMJOC study mentioned in Section 5.1.1 was *c*ommissioned to develop a comprehensive dataset for variables such as projected temperature, precipitation, snowpack and streamflow changes for the Columbia River Basin and the tributary river basins feeding it (RMJOC 2018). The RMJOC study includes data downscaled from the Fifth Coupled Model Intercomparison Project (CMIP5) global climate models[1] to the Columbia Basin. The RMJOC study used global climate model results for two of the four Representative Climate Pathways (RCPs)—RCP4.5 and RCP8.5. The second of the two, RCP8.5, represents a business as usual case, while the first, RCP4.5, represents a more optimistic GHG emissions case.[2] The RMJOC study uses results from 10 of the 41 different global climate models that were available at the time. The study used three different methods for downscaling the global results to the Northwest region and four hydrologic models to develop the needed streamflow data. With the various combinations of methodological choices, the analysis produced 172 individual projections

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[1] CMIP5 was established to provide a framework for producing the models and datasets that were expected to underly the Intergovernmental Panel on Climate Change's (IPCC's) Fifth Assessment Report. See https://journals.ametsoc.org/view/journals/bams/93/4/bams-d-11-00094.1.xml.

[2] RCP 8.5 is often referred to as a "business as usual" case insofar as it represents a case in which society is unable to make the concerted efforts needed to meaningfully reduce GHG emissions from the path that the world is currently on. RCP 2.6 (not discussed herein) is a GHG case in which society makes the changes needed to cause emissions to start declining by 2020 and go to zero by 2100. RCH 4.5 is an intermediate pathway.

(RMJOC 2018). Of these projections, 19 were used to develop the datasets needed for hydro regulations studies (RMJOC 2020).

The RMJOC study is the second study commissioned by RMJOC. The first was performed in the 2009 – 2011 period (RMJOC 2018). Concurrently, the British Columbia (BC) Hydro analyzed the possible climate change impacts in British Columbia, an analysis included in their 2012 Draft IRP (BC Hydro 2012). Both the BC Hydro and the earlier RMJOC analyses used global model results from the Third Coupled Model Intercomparison Project, which provided the data underlying the Intergovernmental Panel on Climate Change Fourth Assessment Report (RMJOC 2018).

Seattle City Light (SCL) commissioned a study that included downscaling of global models in order to examine the impacts on their system as part of their 2016 IRP. SCL commissioned the University of Idaho to downscale 20 global climate models from CMIP5. SCL then had University of Washington researchers develop streamflow projections for eight of the 20 models for the watersheds in which the utility's hydroelectric facilities are located. SCL then selected three of the resulting models to select high, median, and low changes in temperature in the utility service area as well as the annual stream flows at the hydro projects (SCL 2016).

Figure 6-1 shows seasonal shifts in loss of load probability (LOLP) for the NW region based on three different data sets available to the NWPCC: 1949-1978 historic data; 1979-2008 historic data; and 2020-2029 projections from downscaled climate models (NWPCC 2021). The average temperature increases from 50.6 °F to 52.9 °F between the historic and projected cases, and the LOLP shifts from 20.4% LOLP in winter and 10% in summer to 0.1% in winter and 17.2% in summer. If the utility planned for and built to the historic case and if the climate change projection turned out to be correct, they would build resources that may not be needed to meet winter loads and may not build what is needed to meet summer loads.

The Pacific Northwest illustrates the power of peer cooperation and data exchanges. Because of the peer exchanges facilitated by the NPCC[1] and the work of the RMJOC, the northwest has developed a starting point for regional utilities to further investigate the impact of climate on loads and resources. Because of the cost and complexity of downscaling climate data, peer networks might be cost effective avenues for utilities around the country to pursue for tackling the data development aspect of modeling climate change in IRPs.

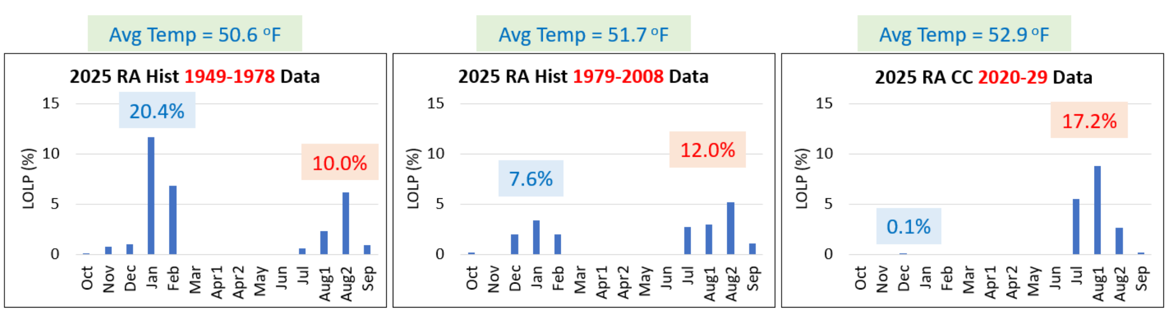

Figure 6-1 Loss-of-Load Probability (LOLP): Comparing Results Between Two Different Historical Data Sets and One Climate Change Projections Data Set (NWPCC 2021).

[1] The NPCC hosted a workshop May 1, 2019, bringing together utility planners to discuss issues related to climate change. See https://www.nwcouncil.org/meeting/sif-climate-change-and-2021-power-plan-workshop-may-1-2019.

6.2 Climate Change Impacts on Thermal Generation

Of the utilities that largely depend on thermal generation, two were noted analyzing potential effects from climate change in their IRPs. As noted in Section 4.4, TVA modeled climate change cases. The TVA IRP took the process of modeling climate change impacts on generation farther than the other IRPs not explicitly identified as hydroelectric dependent. As noted in Section 6.5, Vectren included an evolving set of heating degree days and cooling degree days to reflect climate change for use in the load forecast, but the review of the Vectren IRP did not identify statements indicating the changing temperature variables were reflected in the resource modeling.

One other utility—Ameren—commissioned a consultant, AECOM, to perform a Water Resilience Study to investigate the question of future weather uncertainty, as well as identifying the tools and data that are available to Ameren should it choose to use them in future IRPs. The consultant report looked at average temperatures, rainfall, frequency and severity of drought, and frequency of extreme weather events such as floods (AECOM 2018). The consultant report also evaluated four different publicly available climate change tools and datasets: the World Resources Institute's Aqueduct and Water Risk Atlas, the U.S. Army Corps of Engineers' Climate Hydrology Assessment Tool, the National Oceanic and Atmospheric Administration's Climate Explorer Tool, and the U.S. Drought Monitor (AECOM 2018). The report concludes that "the three regions in the study area are projected to have increased precipitation variability, future drought, and potential water stress for the study horizon through 2030, which are important when considering the need for consistent reliable water resources" (AECOM 2018). It is as yet unclear how this will factor into Ameren IRPs.

6.3 Climate Change Impacts on Hydroelectric Generation

IRPs of Pacific Northwest utilities with significant hydroelectric resources have tended to use models that incorporate many years (70 or more years in some cases) of historical streamflow data and the associated generation. The models randomly select water years from the historical data set for use in the planning models, and results are averaged or otherwise aggregated over large numbers of model runs. Utilities have begun investigating how climate change will impact the distribution of generation across the year, and how the same climate change will impact loads.

The investigation of climate change impacts to hydropower generation in IRPs, until recently, has been limited for utilities such as PSE because they have not been able to access data necessary to effectively model potential changes at the localized watershed level. In their 2017 IRP, PSE discussed how they need data on changes in snowpack and runoff due to climate change to assess how natural stream flows may be re-shaped in the future (PSE 2017). It is not surprising that snowpack and runoff data was harder for PSE to come by in that this data is harder to model in GCMs because snow processes typically need to be parameterized. Parameterization in climate models is used for processes that are too small-scale or complex to be physically represented in GCMs by a simplified process (Mechoso and Arakawa, 2015).

The NWPCC results show potentially significant shifts in the load-resource balance in the Pacific Northwest region. As a result of the climate change cases used, more precipitation is projected to fall as rain than at present. Thus, fall and winter streamflows are higher with an earlier spring runoff occurring and with longer summer periods of low streamflow. At the same time, with warmer temperatures throughout the year, winter heating loads decline while summer cooling loads increase. These impacts combine to reverse the season in which the Northwest faces energy/capacity shortfalls. Without climate change, shortage events occur three or four times as often in the summer as they do in the winter. With climate change, shortage events are almost eliminated in the winter. It is important to note that if the NWPCC did not model both load and resource changes, it might have been possible to miss this significant shift. By 2035, the LOLP is doubled, assuming the existing infrastructure. However, there are additional impacts that make this outcome slightly more manageable. The Pacific Northwest's winter shortfalls tend to be longer (caused by events such as polar vortex events that can last three to four days), while summer shortage events tend to be shorter. The results of the NWPCC modeling showed the average shortage event declines from about 13 hours to about 7 hours, and the event is less intense with the maximum shortfall event falling from 1,000 to 400 megawatts. Thus, the impact is to shift the shortage season to the summer, which means shortage events have shorter durations, although they may occur more often (Turner, et al, 2019).

In their 2020 IRP, Tacoma Power ran a climate change sensitivity case examining how three potential climate change cases could impact loads and resources. The climate change cases selected by Tacoma Power coincide with the cases being investigated by the NWPCC for examining the impact of climate change on loads and resources in their 2021 Power Plan. It should be noted that Tacoma Power does get power from BPA, so some of their resources are from the Columbia River system; however, the hydroelectric resources Tacoma Power owns on the west side of the Cascade Mountains and are not tributaries to the Columbia River system. Tacoma Power found that in two of the three climate cases they studied, their likelihood of outage event metrics improved—changes in the regional streamflow impacted the amount and timing of energy they receive from BPA and caused the model to change how their own resources were operated with the result being an improvement. In the third climate change case they found the LOLP increased beyond their desired threshold, but that the duration and depth of the shortfalls decreased. Tacoma Power noted this was similar to the NWPCC findings for the Northwest region as a whole, with the exception that for Tacoma Power, the shortfall issues occur exclusively in the winter (Tacoma Power 2020).

SCL investigated climate sensitivity in their 2016 IRP process; Appendix 12 documented an analysis of how climate change might affect their resources (SCL 2016). SCL determined that the changes were within the scope of uncertainty they presently manage in their hydro system (Strauch 2019). The SCL conclusion is similar to a conclusion reached by Idaho Power Company in their modeling, that at a high level, the impacts can be mitigated by regulation of streamflow by the existing dams (Charles 2019).

TVA ran a sensitivity analysis for a 3°F temperature increase across all its IRP scenarios and found that overall, this would lead to increases in hydroelectric generation (TVA 2019).

BC Hydro's 2012 draft IRP analysis of historical trends in stream flows in total and across the year did not indicate a need for adjusting the way resources were operated at that time. Looking at the climate change projections, however, BC Hydro noted future changes would very likely be more significant with increased stream flows in winter, spring, and early summer and late summer and early fall stream flows substantially lower (BC Hydro 2012).

6.4 Climate Change Impacts on Load Forecasts

Climate change may impact loads in several possible ways. Both the Tacoma Power and NWPCC analyses modeled the impact on heating and cooling loads in the analyses cited in Section 6.3. In addition, the NWPCC investigated numerous other potential impacts on future loads, such as in-migration from other regions where climate change might make temperatures too extreme as well as changes in the economy, which leads to changes in electrical loads and other secondary impacts (NWPCC 2019).

Vectren included the impacts of climate change in the form of slowly increasing cooling degree day and decreasing heating degree day variables used in their load forecasting process (Vectren 2020). PGE uses a similar trending analysis for heating and cooling degree days with the trend based on actual data from 1975 to the last (unspecified) year of historic data used in the IRP, with cooling degree days increasing gradually and heating degree days decreasing (PGE 2019).

As noted in Section 6.3, the Pacific Northwest utilities' results indicate a change in the amount of precipitation falling as snow, a change in the timing of the snowmelt and the spring runoff, and, as a result, a change in the amount of runoff in the late summer months. When combined with the impact of higher summer temperatures leading to higher cooling loads, this points to an increase in summer loads at a time when hydropower output is decreasing. These changes can impact multiple variables in the IRP, for example, changing the relative importance of energy efficiency options producing savings in summer months compared to those producing savings in winter months (Winkel 2020).

As some states undertake more intensive efforts to deal with climate change, such as retiring fossil fuel generation and electrification of transportation and commercial and residential end-uses, generation and loads in wholesale markets can be impacted, which impacts prices (Jourabchi 2020). The combination of changes in the timing of the water flows and the changes to hydropower generation (decreasing in summer), the increasing temperature leading to increasing air conditioning (also in the summer), and the potential for changes in the wholesale power market points to potential resource gaps and/or potential for cost exposure.

6.5 Decision Making Under Deep Uncertainty

The challenge of planning in this era of uncertainty has given rise to a new framework for assessing climate uncertainties— Decision Making Under Deep Uncertainty (DMDU) (Hallegatte et al. 2012).[1] DMDU methods incorporate forward-looking concepts, tools, and techniques—including Robust Decision Making (RDM),[2] Many-Objective RDM (MORDM), Dynamic Adaptive Policy Pathways (DAPP), Decision Scaling, and Info Gap—that can be used for utility resource planning in the face of such uncertain future conditions (Rand, undated [a]). The principles that underlie the core of DMDU methods are to (Lempert 2021):

- Consider multiple climate futures, not just one single future, during planning.
- Seek robust plans that perform well over many futures, not plans optimized for a single, best-estimate future.
- Keep plans flexible and adaptive.

Traditional planning methods have been upended by climate change, with rising temperatures, shifts in seasons, and changes in the hydrologic cycle forcing utilities to consider how they will

[1] Deep uncertainty occurs when the parties to a decision do not know or do not agree on the likelihood of alternative futures or how actions are related to consequences.
[2] The RDM approach, which can be tailored to incorporate aspects of different DMDU methods, is an iterative analytic process designed to support "deliberation with analysis" —i.e., stakeholder deliberation that informs the kinds of analysis needed to answer uncertain real-world policy problems.

forecast potential changes in supply and demand. Climate change has affected water utilities particularly hard because the commodity they produce and sell to customers—water—is highly vulnerable to changes brought on by climate change. As a result, utilities selling potable water and irrigation water have employed DMDU tools in their water management planning processes.

An example of a real-world application of DMDU was the use of the RDM process to evaluate the robustness of the Metropolitan Water District (Metropolitan) of Southern California's 2015 IRP. While Metropolitan's IRPs have always accounted for hydrologic variability, Metropolitan has placed more emphasis on accounting for how uncertainties beyond the historical variation could affect its investment needs in the coming years. The first step, decision framing, was performed by a small group of water planners and researchers who expanded Metropolitan's modeling framework to investigate the IRP's vulnerabilities to a broader range of uncertainties, including climate change, demographic changes, and changes to Bay-Delta operating conditions. GCM simulations of temperature and precipitation trends calculated and averaged over each of Metropolitan's source basins were run to examine how climatic conditions affect demand for water in the cooperative's service area. To stress-test Metropolitan's IRP, the RDM study team performed a vulnerability analysis to assess how well the IRP performed across a variety of climate futures based on different combinations of temperature and precipitation trends across Metropolitan's supply basins, which revealed the conditions under which the IRP would not meet Metropolitan's objective of ensuring water reliability. The study revealed that the IRP is in fact vulnerable to a potential future in which water shortages greater than 10 thousand acre-feet occur more frequently than 10% of the time for a given year, in which case Metropolitan would have to consider additional adaptation measures to such future difficulties. Although the final stage of the RDM process involves the development of new futures and strategies, this particular study did not specifically define an alternative strategy to the IRP, but instead used the results from the vulnerability analysis to develop a framework for monitoring climate conditions (as well as the other uncertainties presented) to anticipate the conditions that would require IRP augmentation (Rand, undated [b]).

The successful application of DMDU principles in the above case study underscores the potential for DMDU as a tool for augmenting IRPs, especially for electric utilities that increasingly rely on stochastic analysis for evaluating short- and long-term risks in resource planning. Assessing the sensitivities of portfolios to certain risks is a key component of stochastic analysis; DMDU can enhance this process with its emphasis on stress-testing portfolio robustness over multiple climate futures that consider uncertainties in future climatic conditions. In particular, stochastic models have historically focused on representing portfolio costs and economic risk based on input factors such as load demand, capital costs, fuel prices, and emissions costs; as utilities begin to examine portfolio sensitivities in the context of potential climate change impacts, the use of GCMs in conjunction with statistical and dynamic downscaling methods has increased, highlighting the applicability of the DMDU approach for electric providers faced with uncertain and complex future regional climate projections.

7.0 Other Issues Not Covered by Original Research Questions

Some issues arose during the development of this white paper that merit mention, including sustainability reports and cross-over IRPs that cover more than just electricity planning.

7.1 Sustainability Reports

One fact that became apparent is that a lot of utilities are performing sustainability reporting to various entities. Some are using templates developed by Edison Electric Institute (EEI). EEI developed an environmental, social, governance, and sustainability (ESG/sustainability) template used by Vectren (CenterPoint Energy, the owner of Vectren), Duke Energy, and Georgia Power's parent company, Southern Company (EEI n.d.).

Xcel Energy (parent company of Xcel Upper Midwest and SPS) and Southern Company use or have used Sustainability Accounting Standards Board (SASB) reporting formats (SASB 2018).

In some cases, more information was gleaned about the utility's water usage from the sustainability reporting than from the IRP. While in some instances the utility is simply reporting, in other instances the sustainability report commits the utility to reducing water usage.

7.2 Cross-Over IRPs

An area of research uncovered during examination for this white paper is cross-over IRPs—IRPs that cover electricity and water, or other utility services such as natural gas or wastewater. Although an example of a cross-over IRP was not found, an analysis of the potential for cross-over IRPs was discovered (Conrad et al. 2017). The study authors note several areas in which a joint IRP could be beneficial to both a water utility and an electric utility. An example might be in watershed planning to ensure the electric utility has the cooling water they need while the water utility has access to the quality and quantity of potable water they need. Other areas include collaboration on renewable resources, on energy efficiency projects, or on demand management (water pumping is frequently a load that electric utilities work with water utilities for purposes of controlling the load for peak shaving).

A study conducted by PNNL, NREL, and University of Washington in 2020 looked at the impact of climate change on water availability and its propagation through the Western U.S. power grid. The study found that changes in water availability in one region trigger a response in other regions and that regional dependencies are critical to evaluating climate change impacts. Climate change impacts on water availability in the Northwest result in future changes in power generation in other regions and overall regional power flows. Generation from the desert Southwest plays a critical role in compensating for variations in water availability and generation in other areas through the West (Voisin 2020). This study points to the importance of regional forces, beyond a single utilities' generation footprint or service area, in shaping grid and market conditions under drought and climate change. These forces and conditions can impact resource adequacy and risk as well as a utility's preferred resource portfolio in IRPs.

Another study that combines water and the electric grid was led by Sandia National Laboratories; the study looked at the implications for water availability on the long-term planning and operation of the transmission grid (Tidwell 2015). As part of this project, the team developed water availability data to inform generation expansion planning in the Western Electricity Coordinating Council (WECC) and in the Electric Reliability Council of Texas (ERCOT). The project developed a significant body of data concerning water usage for generation and other uses, water costs, environmental risks, and climate variability (Tidwell 2015).

7.3 State Regulations Related to Water Reporting in IRPs

Some states, notably Arizona, Colorado, and New Mexico, require utilities to report water usage of generating resources.

- The Arizona Corporation Commission requires reporting of water consumption in IRPs in Article 7 – Resource Planning and Procurement, Rule R14-2-703 (Arizona 2020).
- The Colorado Public Utilities Commission requires reporting of water in Rule 3604 – Contents of the Resource Plan, specifically 3604(h), in which water consumption for each generating unit is required as well as for the system as a whole (Colorado 2020).
- The New Mexico Public Regulation Commission requires reporting on the environmental impacts of existing supply-side resources, including water usage, in Rule 17.7.3.9(13)(c) (New Mexico 2017).

The Minnesota Public Utilities Commission issued an order, on May 10, 2013, in the docket addressing Minnesota Power's 2013 IRP, that required Minnesota Power (now Xcel Upper Midwest) to submit a description of how drought and high water temperature might affect generating plant availability and how this was taken into account in the IRP (Minnesota PUC 2013). It was this order that Xcel responded to with the use of the capacity metric discussed in Section 4.1.2.3.

The ReliabilityFirst Corporation (one of the Federal Energy Regulatory Commission's approved Regional Entities that ensure the reliability of the bulk power grid) established a reliability standard, BAL-502-RF-03, addressing planning resource adequacy analysis, assessment, and documentation (RF 2017). Requirement 1.4 addresses factors affecting resource availability, including 1.4.6, "impacts of extreme weather/drought conditions that affect unit availability" (RF 2017). It was this standard that Vectron was addressing with the capacity metric discussed in Section 4.1.2.3.

7.4 Water Rights

When reviewing the NREL graphics, Figure 2-3 and Figure 2-4, it is notable how few resources are in the area west of the Rocky Mountains. A part of that is likely due to the fact that water rights are tradeable/purchasable commodities in many western states. In these states, water rights are based on a prior appropriation system, in which water rights can be granted as long as they do not impact existing users with water rights, and once the water rights have been acquired, the rights remain with the holder as long as the water continues to be used.[1] In Utah, it is possible to review the application for water rights for PacifiCorp's Huntington Power Plant (Utah 2021). In many, if not all, of these states water rights can be sold, so if you close a power plant you can sell your water rights. Thus, water rights are valuable commodities to the holder of the water rights, as well as to the community surrounding the generating station. News stories about plant closures include discussion from the local community around their hopes that water rights remain in the community to support economic development when the generating plant closes. See, for example, Runyon 2020 for a story about a coal plant owned by Tri-State (Runyon 2020) and Imse 2020 for a story in which Xcel Colorado states they plan to hold onto their water rights at least for the time being for potential use in whatever resources are ultimately needed to replace coal plants (Imse 2020).

[1] Water rights are a complex subject upon which books are written and careers are built, so this white paper can only touch on water rights at a high level and briefly.

Availability of water rights is a limiting factor. For example, PacifiCorp's IRP includes dry cooling for all combined cycle combustion turbine options to allow them to be sited in areas where water is limited (PacifiCorp 2019).

7.5 Carbon-Free and Renewable Standards Lead to Lowered Water Usage

One clear lesson from the review performed for this white paper is that as utilities close down coal-fired power plants, in part because of the age of the plant and in part because of the need to do so to meet environmental standards and renewable portfolio standards, water usage is declining. When examining the IRPs, it is clear that the majority of utilities reviewed have set retirement dates for the majority of their coal-fired fleet. As this happens, the resilience question related to water used for generation will be less and less of a problem.[1] Wind uses no water. Solar uses far less water than thermal generation, and combustion turbines can be operated using dry cooling or hybrid dry-water cooling, which means the replacements for coal generation will be significantly more water efficient. The outlier in this, however, is nuclear power. Of the IRPs reviewed for this white paper, utilities with nuclear power intend to seek to extend their plant licenses when the licenses expire. Many utilities with nuclear power are targeting what they term "carbon-free" resource portfolios, meaning a combination of nuclear power and renewable generation (see for example, APS 2020). Thus, the question of cooling water will remain with nuclear power plants, but the decline of coal-fired generation will broadly reduce the magnitude of any potential problem related to water sufficiency for thermal power generation.

8.0 Conclusion

IRP is the process by which a utility projects future customer needs and identifies the resource mix that is most likely to meet those needs while balancing cost and risk. IRPs examine issues that can cause uncertainty for the resource portfolio. This white paper builds on the knowledge of how electric utilities are addressing uncertainty, in this case, by how IRPs treat uncertainty related to water supplies and the potential impact on generating capacity caused by water supply issues. It also explores how electric utilities are considering the impact of climate change in their IRPs. By identifying best practices for analyzing water availability and climate change this white paper provides information about tools for analyzing the weather-related issues utilities will face in the future.

The best practices identified in IRPs include the following:

- Development and presentation of a plan showing how water sufficiency is maximized for all thermal generating resources dependent upon water supplies for cooling
- Use of total water consumption for power plant cooling as a metric to be used in selecting the preferred resource portfolio
- Use of the IRP planning process to identify the best course for dealing with resources facing water stresses to weigh alternative costs and benefits and the impact on the overall resource portfolio

[1] U.S. Energy Information Administration Frequently Asked Questions state that in 2020 coal generation was 19.3 percent of total generation, natural gas was 40.3 percent, petroleum was 0.4 percent, and nuclear represented 19.7 percent. See https://www.eia.gov/tools/faqs/faq.php?id=427&t=3

- Use of a generating capacity metric that explicitly accounts for the impact of forced outages and deratings, as well as, in particular, to capture expectations for outages related to future water availability issues
- Planning for the impacts of climate change on generating capabilities (especially in the case of hydroelectric-dependent utilities) and loads
- Developing weather and water projections that take into account changes to historical patterns based on climate change, through using and downscaling climate models, basing projections on only the most recent past (~15 years) rather than the full historical record, or conducting customized regression analysis that addresses changes to weather patterns
- Considering the impact of climate change on load projections by evaluating the impacts to number and magnitude of heating degree days and cooling degree days and the potential for population changes due to weather trends.

IRPs of utilities/entities with significant hydroelectric generating resources have started to identify the impacts of global climate change on their systems. Generally, these IRPs have not identified reduced hydroelectric generation as a result of climate change, and one IRP, TVA 2019, indicated climate change could lead to increased hydroelectric output. However, the IRPs have reported the following potential impacts of concern:

- Timing of resource availability – In the Pacific Northwest, climate change appears, given the current estimates, to cause more precipitation to fall in the form of rain and less as snow, to cause more runoff in winter months, and to reduce the runoff in spring and late summer, meaning more generation in the winter and less in the summer.
- Load changes – Also in the Pacific Northwest, climate change appears to point toward increased cooling loads and decreased heating loads; in a region that is historically winter peaking this is a shift impacting not only the question of supply resources for summer and winter but also demand side resources.
- Secondary impacts – As states respond in various ways to climate change, either proactively by undertaking efforts such as electrification, or reactively by addressing issues as they arise, the changes will likely have impacts on the retail loads and on wholesale markets.

Taking the areas of concern as a group, if you combine lower summer generation output with higher summer loads and combine this with the possibility of reduced availability of wholesale power in the market and/or higher prices in the wholesale market, global climate change represents an issue that should be addressed more widely in IRPs. Utilities need to look beyond their service territory as impacts of climate change have interregional effects.

DMDU is a framework for addressing climate uncertainties that has been used in the water industry. As the electric grid transitions to more weather-based renewables and as impacts of climate change become more pronounced, the DMDU framework and principles may be increasingly relevant for electric utility IRPs to address the uncertainty associated with complex future regional climate projections.

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