INTEGRATED RESOURCE PLAN (IRP) 2019 UPDATE

Public Utility District No. 1 of Douglas County
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East Wenatchee, WA 98802
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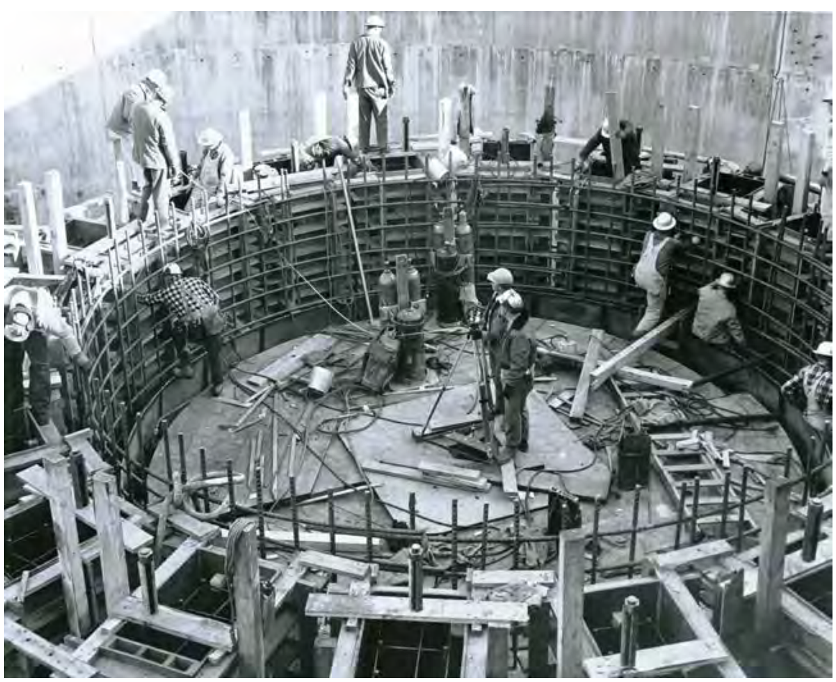
1.0 OVERVIEW OF DOUGLAS PUD

Douglas County Public Utility District ("Douglas PUD" or "The District") was organized in 1936. Formed by the people of Douglas County, Douglas PUD became one of the first non-profit, locally-owned electric distribution systems in the state. In its effort to provide the modern conveniences of electricity to rural customers at the lowest possible costs, Douglas PUD began to acquire over 400 miles of existing power lines from investor-owned utilities throughout the 1940s. Utilizing this system and the power supply of the Bonneville Power Administration, Douglas PUD began operations in 1945.

Building upon its success of serving rural customers, Douglas PUD worked to license and construct the Wells Hydroelectric Project in the late 1950s and early 1960s. This unique project, located on the Columbia River near the town of Pateros, was completed in 1967. After completion, the 840 megawatt Wells Project gradually became Douglas PUD's primary power supply resource. It still is today.

Douglas PUD's share of the Wells Project, together with its portion of the output from the Rocky Reach Hydroelectric Project, has historically been sufficient to meet the needs of approximately 15,200 electric customers in Douglas County. The Wells Project has become a model for providing clean, efficient and reliable hydroelectric power. The project supports the most successful juvenile fish bypass system on the Columbia River and funds several salmon and steelhead hatcheries. True to the vision of its first organizers, the prudent direction of its locally-elected commissioners and the hard work of its staff, Douglas PUD has developed one of the most environmentally-friendly, cost-effective and reliable power systems in the nation.



Douglas PUD received its initial license for Wells Dam on July 12, 1962. Construction of the project took place throughout the early 1960s with commercial operation beginning in 1967.

2.0 THE IRP PROCESS

The Energy Policy Act of 1992 (P.L. 102-486) encourages utilities to develop and implement an Integrated Resource Plan (IRP), which is a document and underlying process of evaluating loads and resources through some planning horizon. An evaluation of the full range of both supply-side and demand-side options should take place when selecting new resources.

This 2019 Update to the IRP is a voluntary, locally-developed process designed to assist commissioners and staff in meeting the current and projected utility needs for Douglas PUD, in consideration of any and all requirements for renewable generation.

The District updated its IRP most recently in 2007 and 2012. This 2019 Update captures planning activities associated with increased load growth within the District's service territory, and an evaluation of changes within the industry, to include new state requirements for renewable generation.

3.0 PUBLIC PARTICIPATION

Since its formation in 1936 by Douglas County residents, Douglas PUD has had a long-standing tradition of public involvement. For that reason, local values will always be reflected in Douglas PUD's planning and operations. From the beginning of the Integrated Resource Planning process in 1992, Douglas PUD's approach to developing its resource plan has involved ample opportunities for public discourse.

Prior to adopting this 2019 Update, information will first be presented to the board, a public meeting will be held for the purpose of accepting public comment, and finally the board will take action on the plan with respect to its approval.

4.0 CHANGES SINCE THE 2012 UPDATE

Significant changes have taken place since the adoption and implementation of 2012 Update. These changes have occurred both within the District's service territory and in the power industry as a whole. This section addresses the changes the District is facing from both a load and resource perspective. An industry outlook is also included.

4.1 Resources

Wells Project

Douglas PUD received a FERC Notice of Authorization for Continued Project Operation on May 31, 2012, and an Order Issuing New License on November 9, 2012. The new license includes a 40-year term. The Wells Project continues to meet the bulk of the District's load obligations.

Following the expiration of the District's legacy power sales contracts with its original power purchasers, the District gained access to a greater share of Wells output on September 1, 2018.

Three of the four original power purchasers entered into contracts with the District for output through September 30, 2028. The amounts conveyed to each of these power purchasers is determined by a schedule the District completes annually, with the amounts decreasing as the District's load increases. The objective was to ensure the District could withdraw a sufficient amount of Wells output to meet its native load. The District has no obligations to these power purchasers at the expiration of this new agreement.

The District also has longer-term commitment to the Colville Tribe and to Okanogan PUD for output at Wells. The Colville Tribe has access to 5.5 percent of Wells Output. Okanogan has the ability to grow into a 30 percent share of Wells output (28.65% net of the Colville obligations), though its take is limited by need, as calculated on schedules completed by both Okanogan and the District annually.

Rocky Reach Project

The District and Public Utility District No. 1 of Chelan County entered into a power sales contract dated April 6, 1976. This agreement granted Douglas PUD the right and option to extend the initial term of its power sales contract for Rocky Reach output for five successive periods of ten years. The District is currently within its first ten year option, which expires October 31, 2021. The District served notice in July of 2015 to extend the term by another ten years, commencing November 1, 2021.

Nine Canyon Wind Project

Douglas purchased, and has rights to, a 10.23 percent share of the combined output of phase one, two and three of the overall Nine Canyon Wind project, managed and operated by Energy Northwest. It has a total installed capacity of 99 MW. The land leases with private owners expire on June 30, 2030. There is uncertainty related to continued operations beyond that date. Since the project does not produce firm resources to meet load, its output is not factored into this IRP process.

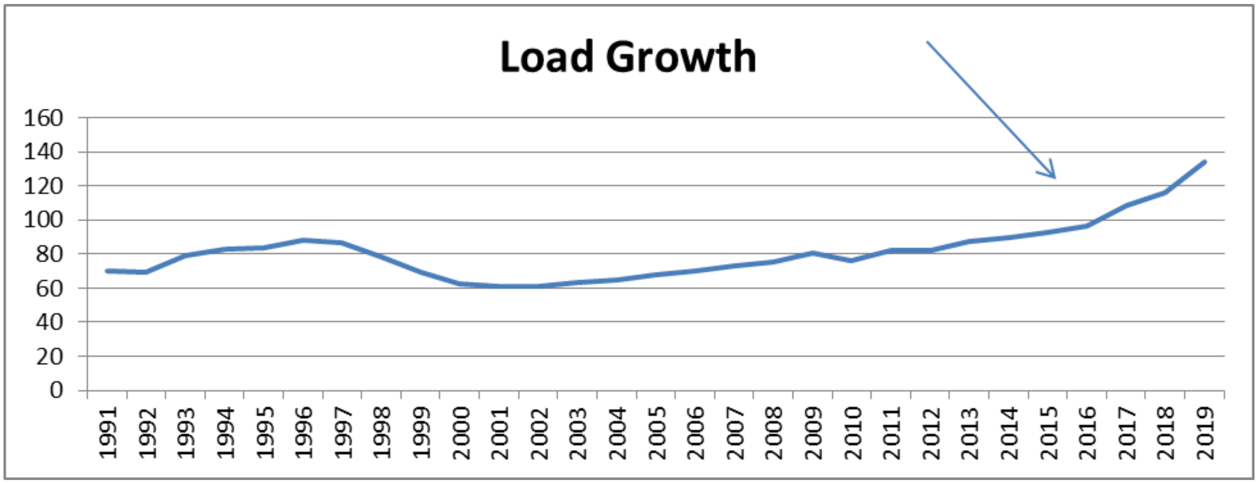
Bulk Power Purchases/Exchanges

The District entered into an exchange agreement with Avista Corporation in which the District conveys a ten percent share of Wells Project output in exchange for a firm block of power, to be delivered to Douglas Switchyard. The term of this arrangement is from October 1, 2018 through December 31, 2023, and between 47 and 48 aMW will be delivered for the balance of the agreement. One of the goals of this exchange is to mitigate the District's hydro risk.

4.2 Load Growth

The District has experienced significant load growth within its service territory. In addition to load currently under contract, much of which has not been fully ramped-in, the District continues to receive interest from new large load users. Load growth in the county averaged 1.45 percent annually between 1991 and 2016. In 2017 and 2018, however, native load increased 9.6 percent annually, or 20.5 percent in the aggregate. Moreover, as compared to the first seven months of

2018, 2019 loads are on average 19.8 percent higher from just one year ago. The graph below shows the inflection point where the rate of increase adjusted upward steeply (*Graphically, the balance of 2019 is forecasted).



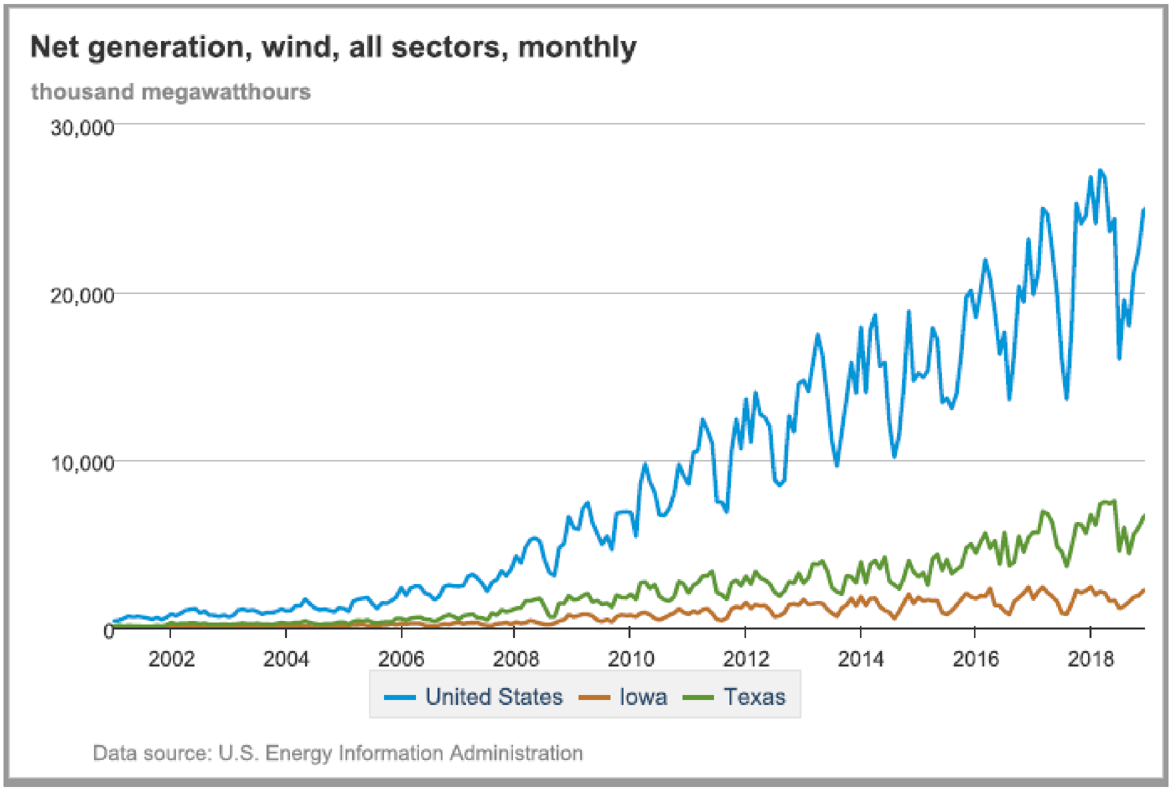
Much of the increase can be attributed to non-diverse loads. Such loads consume the majority of the capacity made available, and are relatively flat in nature. The District gained its first large non-diverse load when it executed a contract with Sabey Corporation in 2006. Today, the District estimates that it has 51 megawatts of capacity currently serving non-diverse loads. Additionally, the District has contracts in place that could well over double the amount of capacity used to serve non-diverse loads. The impetus and popularity of these non-diverse loads is due to data-driven computer processing activities. Crypto-currency mining is an industry that is new to Douglas PUD and is dominating current load growth.

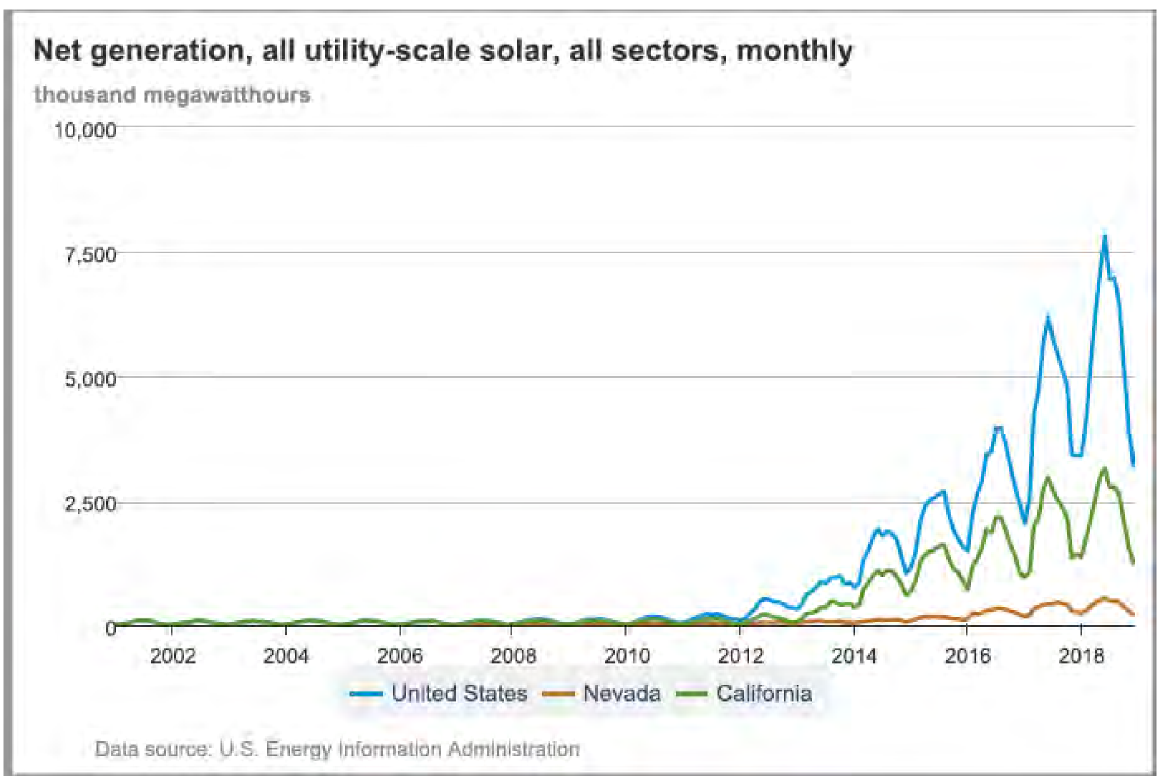
Since the initial influx of demand, the District has instituted a number of different policies. One of these policies is the requirement that large contract customers must enter into a special contract for loads in excess of 1.5 MW. Although the District continues to receive large non-diverse load requests, the District currently (as of September 2019) has a moratorium in place, and is not actively connecting non-diverse loads.

4.3 Renewable Resource Development – Industry Evaluation

Wind and Solar developments have increased dramatically over the last decade, and solar in particular has seen significant growth since the 2012 Update. In 2008, utility scale wind generation equaled 55,363 GWh. By the end of 2018, wind generation totaled 274,952 GWh. Utility scale solar, on the other hand, has increased from 864 GWh in 2008 to 66,604 GWh in 2018. Solar has been the popular choice for most developers over the last couple of years due to economic and other considerations.

Below are graphs showing the effects of solar and wind installations on sector production, per information provided by the Energy Information Administration (EIA):





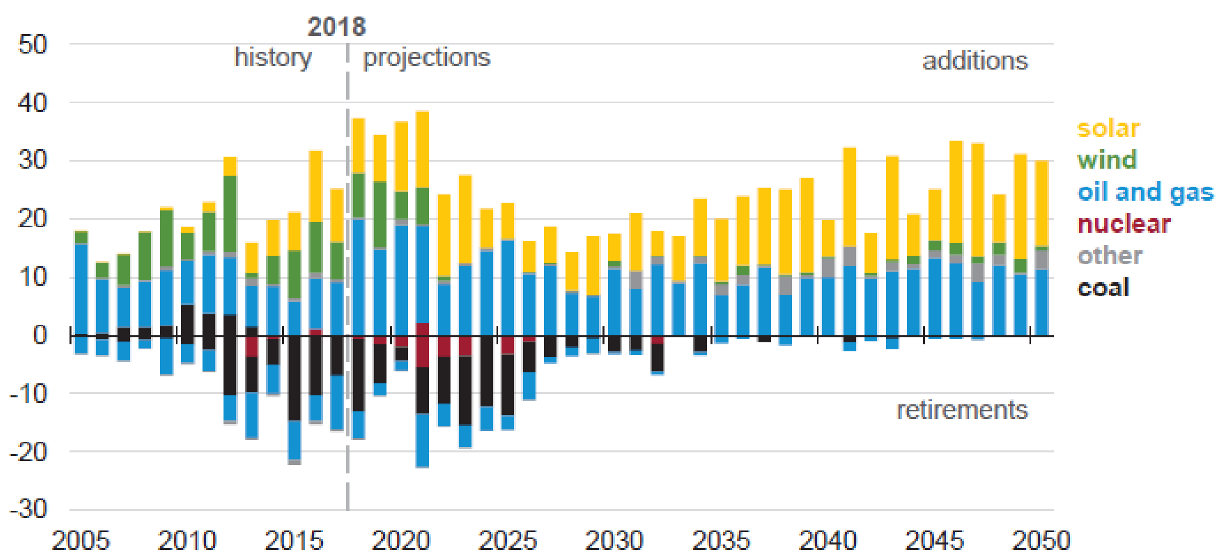
Federal production incentives for wind development as well as state laws, such as the Initiative 937 law, have contributed to the rapid pace of renewable development in Washington State.

Additionally, California and Oregon have strict Renewable Portfolio Standards (RPS) requiring predominantly renewable generation to serve load. California's current policy requires 100% renewable generation by 2045.

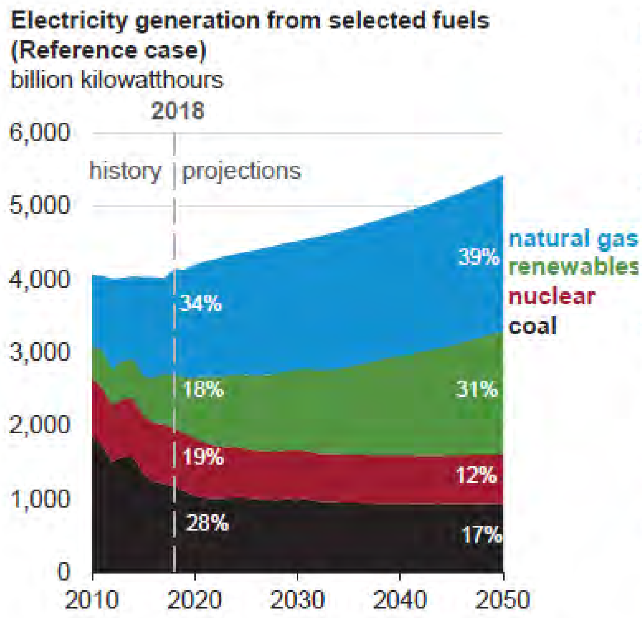
New laws in Washington State will further incentivize renewable investment. Governor Jay Inslee signed Senate Bill 5116 in April of 2019, requiring utilities to be 100% carbon neutral by 2030, 20% of which can be satisfied by renewable energy credits. By 2045, utilities must be self-generating 100% of its resources from clean energy sources.

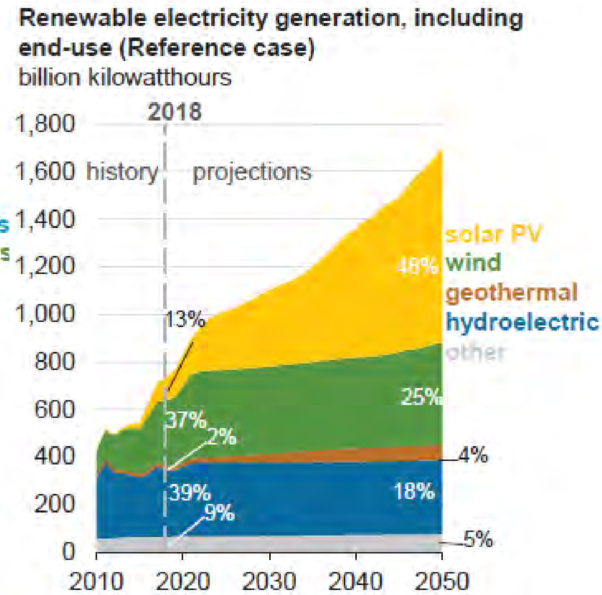
Legislature and policy, coupled with the Solar Investment Tax Credit, due to expire in 2024, have spurred additional investment in renewable resources, regardless of demand. This has fundamentally changed the industry. Below is a graph, published by the EIA, showing their projections of additions and retirements on the grid through 2050.

Annual electricity generating capacity additions and retirements (Reference case)
gigawatts



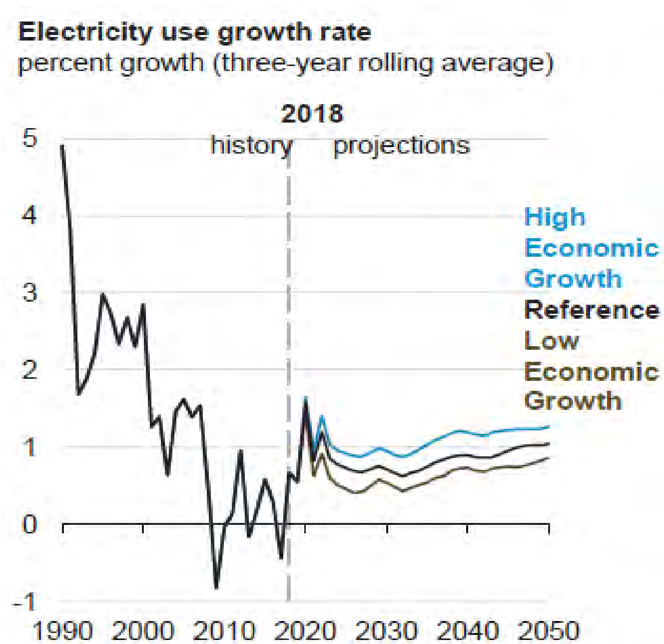
Given the premises above regarding additions and retirements, the graph below reflects the anticipated fuel mix within the industry for the 30-year planning horizon.





Solar is anticipated to eclipse wind and hydro as the dominant renewable resource, while geothermal will have carved out a small slice of the pie. Coal is expected to decrease, while natural gas realizes a slight uptick because of its need to firm-up renewable resource additions.

On the load side, growth has been flat nationally, sometimes negative, as conservation increases to aid in meeting the Renewable Portfolio Standards. Going forward, however, demand is expected to continue at a nominal growth rate, and the EIA anticipates about 1 percent year-over-year growth for the foreseeable future. The graph below demonstrates projected growth under different economic conditions.



As the District considers its expected net position, the above outlook will impact the District's ability to market its surplus resources. In summary, nominal growth should continue, which is a reversal from the trend in the early part of the decade, where load was decidedly in a downward swing. The ability of the larger system to meet load, in consideration of the reductions in coal, will need to be met by renewables, which often lack storage and firm capacity. The Northwest Power Pool is currently conducting a resource adequacy assessment for the northwest, as concerns have arisen about the sufficiency of capacity and storage in the region, even as surplus conditions persist seasonally.

5.0 EXPECTED NET POSITION OF THE DISTRCT

Any assessment of the District's net position will rely upon any number of different assumptions with respect to both loads and resources. The information provided below relies upon the District current projections of loads and resources, and areas with inherently high degrees of uncertainty will be noted.

5.1 Resources - Wells

The District's Wells resource is an 840 MW project with ten units in-service and a license which is active through 2052. Due to long-term maintenance activities associated with the turbine and generator rebuild project, 9-units are projected through the ten year planning horizon. Additionally, the District conducts biennial maintenance on its units in both the early spring and fall, along with other work as needs arise. Unplanned maintenance activities are generally not long-term in nature, and therefore not modeled.

From an energy evaluation, the Wells Project has produced annual net generation (less station service and project line loss) of 4,277,901 MWh since 1991. Project obligations in the form of encroachment to BPA and Canadian entitlement to the U.S. entity, through BPA, are first carved out from generation at Wells. Canadian entitlement averages 205,200 MWh annually with a capacity impact of 41 MW. CHJ Encroachment averages 251,000 MWh annually with a variable hourly capacity impact typically ranging between 20 MW and 40 MW.

Long-standing commitments to Colville for 5.5 percent and to Okanogan for up to 30 percent (net of the Colville allocation) exist through the planning horizon of this IRP. The Colville share persists for as long as the District holds a FERC license to operate the project, and the Okanogan share will increase commensurate with Okanogan PUD's load, up to a maximum of 30 percent through 2068. For the purposes of this IRP, and in a posture of forecasting conservatively, the District will assume that the Okanogan share increases to 30 percent in January, 2029. This assumes that Okanogan does not continue to receive BPA power.

5.2 Resources – Rocky Reach

The District has options to extend its 5.54 percent share of Rocky Reach out through 2051. The Rocky Reach Project has a stated capacity of 1299 MW. There is no encroachment obligation to Wells, though its Canadian Entitlement is about 43 aMW, with a capacity impact of about 64.5

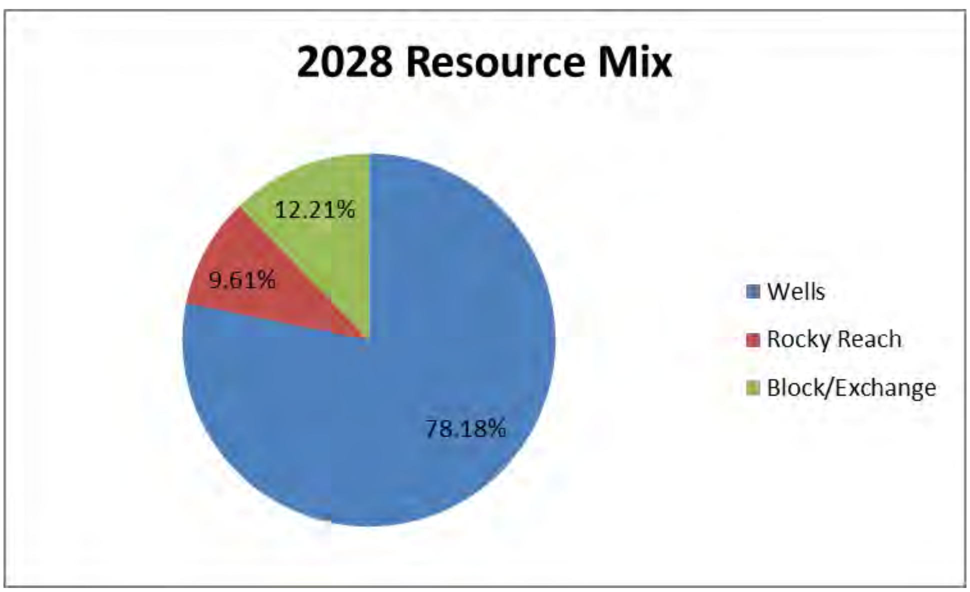
MW. Over the last two years, capacity at the Rocky Reach Project has averaged about 960 MW, prior to reductions from project obligations, with the District's share of that capacity being 53 MW. Expected annual energy for the District's share is assumed to average 323,500 MWh, given average hydro conditions.

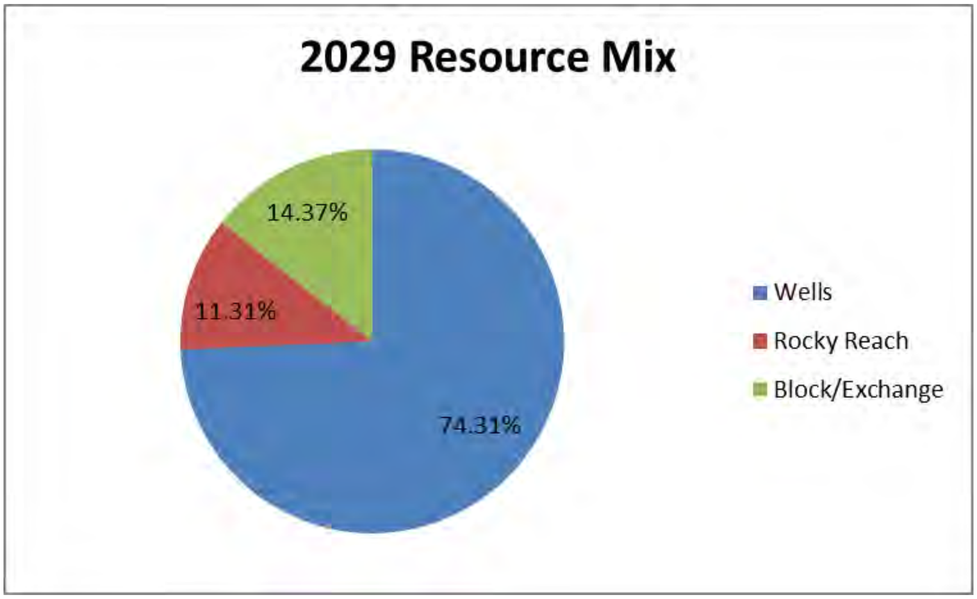
5.3 Bulk Wholesale Purchases/Exchanges

As indicated in section 4.1 of this IRP, the District entered into an exchange agreement with Avista Corporation whereby the District conveys 10 percent of Wells Project output for a flat block of power, to be delivered to the District's system at Douglas Switchyard. The current schedule is 48 MWh, though it will drop to 47 MWh for the final three years of the deal, concluding December 31, 2023. This deal enables the District to mitigate some of its hydro risk, and the District is interested in continuing a similar arrangement at the conclusion of this agreement. For the purposes of modeling, this IRP assumes that a similar arrangement will be executed beyond 2023.

5.4 Resource Mix

Together, the resources noted above represent the District's current resource stack. Calendar year 2029 represents a change in the mix, as the District's share of Wells could decrease, inverse with Okanogan's take of the Wells Project. A graphical depiction of both 2028, as well as the period beyond 2028 is provided below.





5.5 Load Profile

The District's load is comprised primarily of residential, commercial, irrigation, and industrial customers, and heating and cooling load represent much of the base load within the service territory. As such, historically, the District has been a winter peaking utility, and this is anticipated to continue. Since most of the load the District has added over the last two years has been non-diverse in nature, the peaks may soften on a percentage basis. The absolute difference between the District's average peak and average load from the previous two years is 103 MW or 192 percent of the average annual load. The District reached a new all-time peak of 239 MW on February of 2019.

As discussed in Section 4.2 of this IRP, the District has realized significant load growth over the previous two years.

The District does not have any curtailable load through demand response programs, and demand-side management programs are currently limited to a weatherization program the District supports through the Chelan-Douglas Community Action Council.

Currently, the District carries its reserve obligation at the Wells project, which reduces capacity year-round, and reduces energy during times where inflows either exceed capacity at Wells. The District is considering adding a load within its service territory to produce hydrogen. The magnitude of this load is yet to be determined. This load could be operated in a manner that could reduce or eliminate the need to carry reserves at Wells. Since this load would be operated by Douglas PUD, and because it's a curtailable load, the hydrogen load would not pose a capacity impact to the District's net position. Additionally, the District would not operate this load during a period of resource insufficiency, so this potential load will be ignored for the purposes of this IRP and determinations regarding resource adequacy.

6.0 MODELING (ENERGY AND CAPACITY)

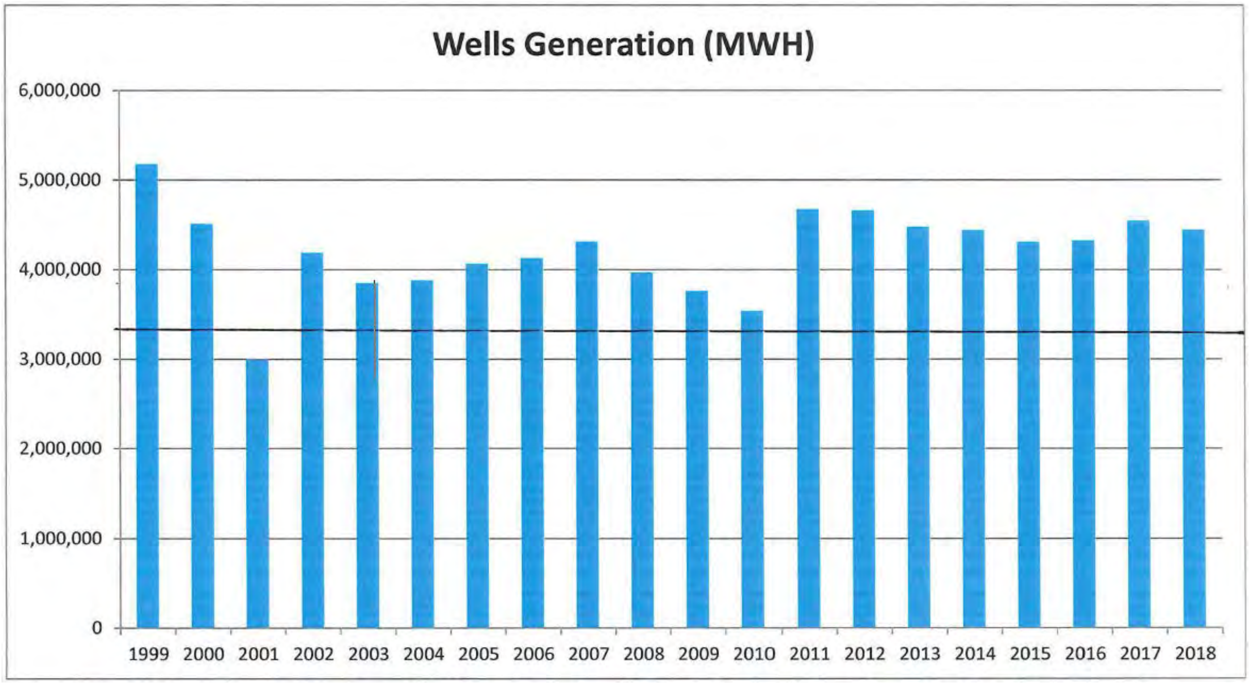
Several assumptions must first be made prior to a proper evaluation of net position. The key assumptions will be noted in this IRP.

Hydro Record Utilized in Modeling and other Assumptions

With respect to hydro conditions, in reviewing the previous 59-year record of inflows into Grand Coulee, as indicated by the Northwest River Forecast Center (NWRFC), five years within this record have resulted in inflows of less than 80 percent of average. Most recently, 2015 produced inflows at a calculated 77 percent of average. In the scope of planning it is important that the District is able to meet its load obligations during most water conditions. Even under 100% (average) hydro conditions, measured annually, it would not be unusual for certain months to deviate considerably from that average.

The usable shape of inflows into Wells has changed materially over the previous 59-year water record, and the correlation between water year and generation at Wells is not exact. Some of this change can be attributable to changes resulting from environmental requirements like the Biological Opinion ("BIOP"), which results in more spill at Wells. Canadian operations also create a disconnect between water year and generation at Wells.

For proper evaluation, a truncated Wells generation record was used, since the truncated water record is assumed to be more predictive of expected future generation, given the constraints and operations currently in place. In order to provide the necessary sensitivities related to hydro conditions, and since the District is interested in modeling critical water scenarios, 80 percent of average generation will represent the District's critical water analysis. Below is a graph showing generation at Wells, prior to reductions from project obligations, the black line represents 80 percent of average generation. Only the calendar year 2001 falls below the line. Note that the shape of inflow varies from year-to-year, which often creates surplus generation in one period with the potential of creating deficiencies in other periods, even if the annual generation appears close to average. For this reason, the District would hesitate to use a less rigorous threshold representing critical generation.



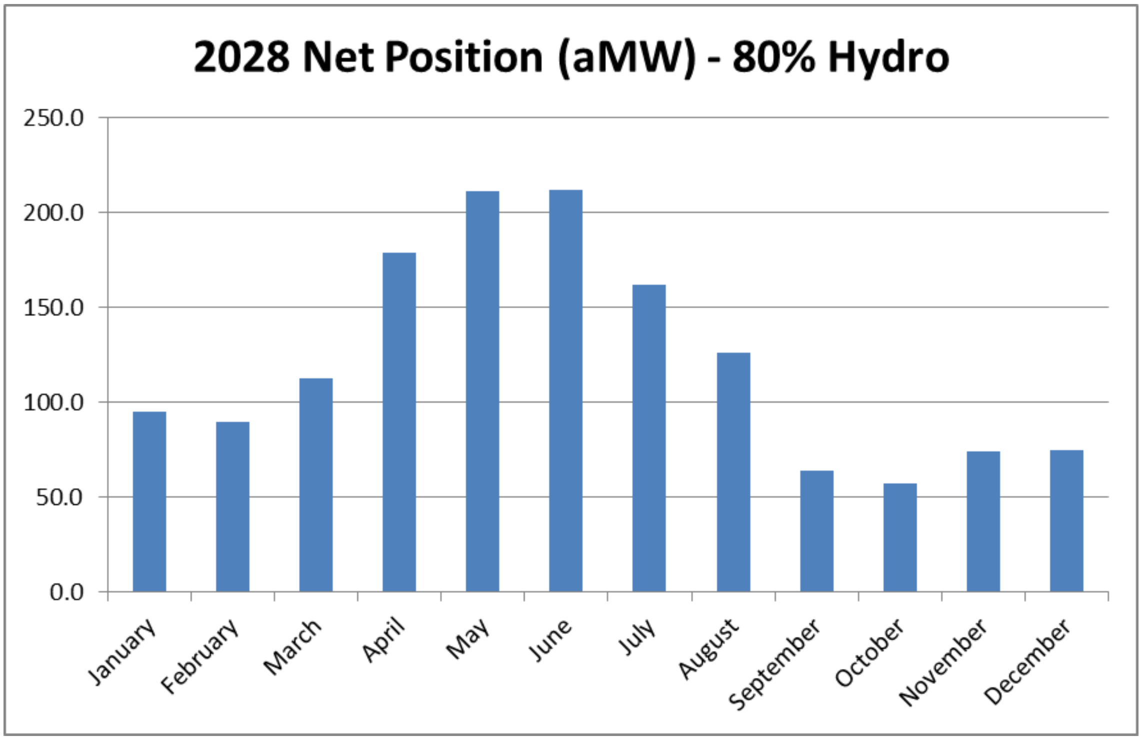
Another key assumption related to contracts the District executed with the three of the four original power purchasers. While these purchasers have rights to output at Wells, this contract allows the District to prospectively withdraw a sufficient amount of Wells in order to meet its load. This is accomplished through calculated schedules based on load and expected generation at Wells and Rocky Reach under critical hydro conditions. For simplicity, this IRP will ignore the amounts made available to the purchasers, with the exception of any agreed upon exchanges, since such amounts are considered to be surplus sales, and not obligations which could infringe upon the District's ability to meet load.

6.1 Net Position

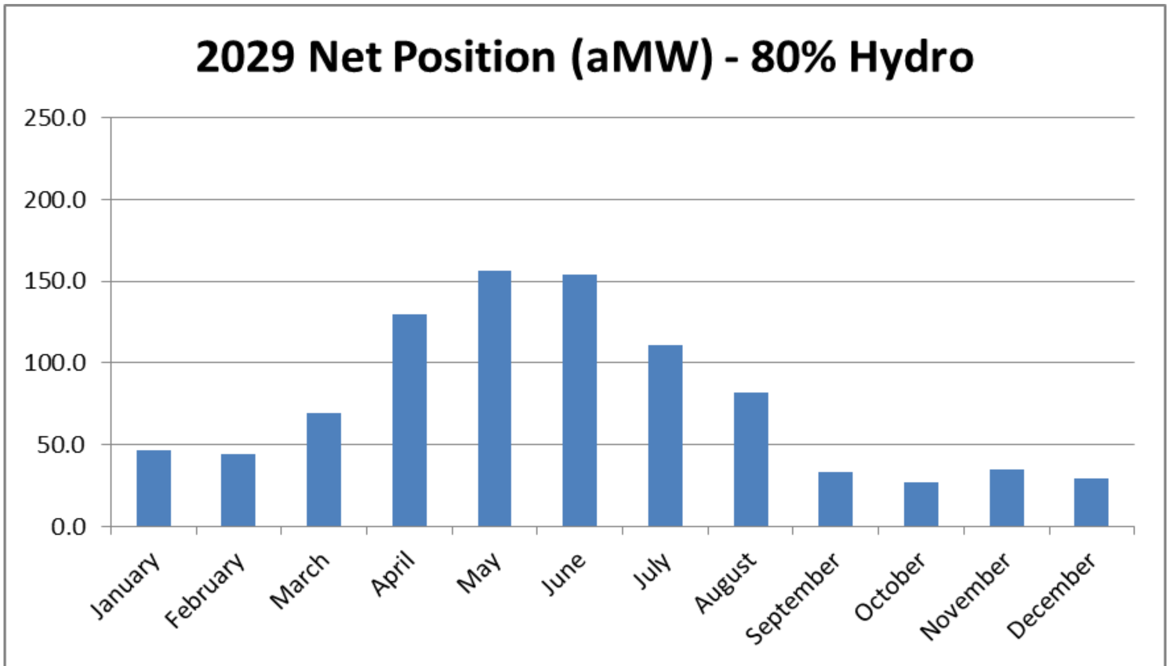
When determining resource adequacy, it's important that an evaluation include both an energy outlook as well as a capacity outlook. That is, when looking at the relationship between resources and loads, it's important that there is sufficient "fuel" to meet load over the course of the month or year, but it's equally important that the resources can meet peaks observed throughout the year, often an hour or two in duration. As the District is located in a climate where there are four distinct seasons, variations in load from one hour to the next, and from one season to another, can be extreme.

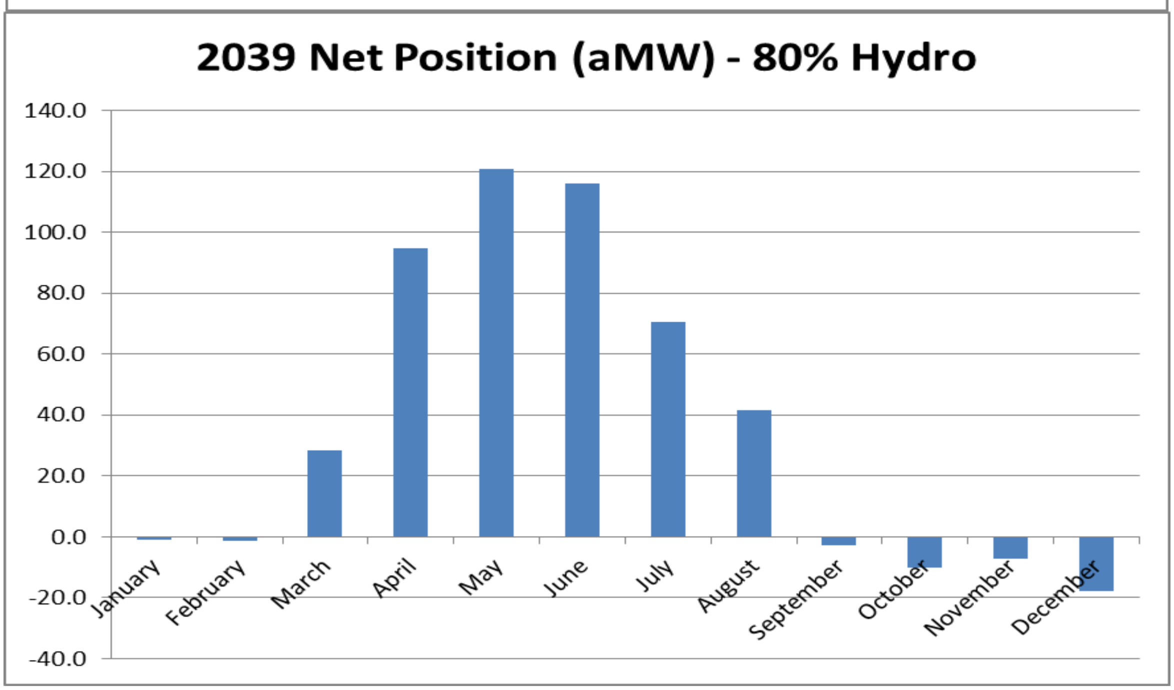
Energy Evaluation

From an energy outlook, given certain assumption about Okanogan's load, which impact the Douglas share of Wells, the District is expected to be surplus through 2028. This assumes 1.5 percent load growth, consistent with the historical record, while industrial load was calculated discretely based on the nature of each operation's expected ramp. The shape of the surplus varies by month. Below is the outlook for calendar 2028.

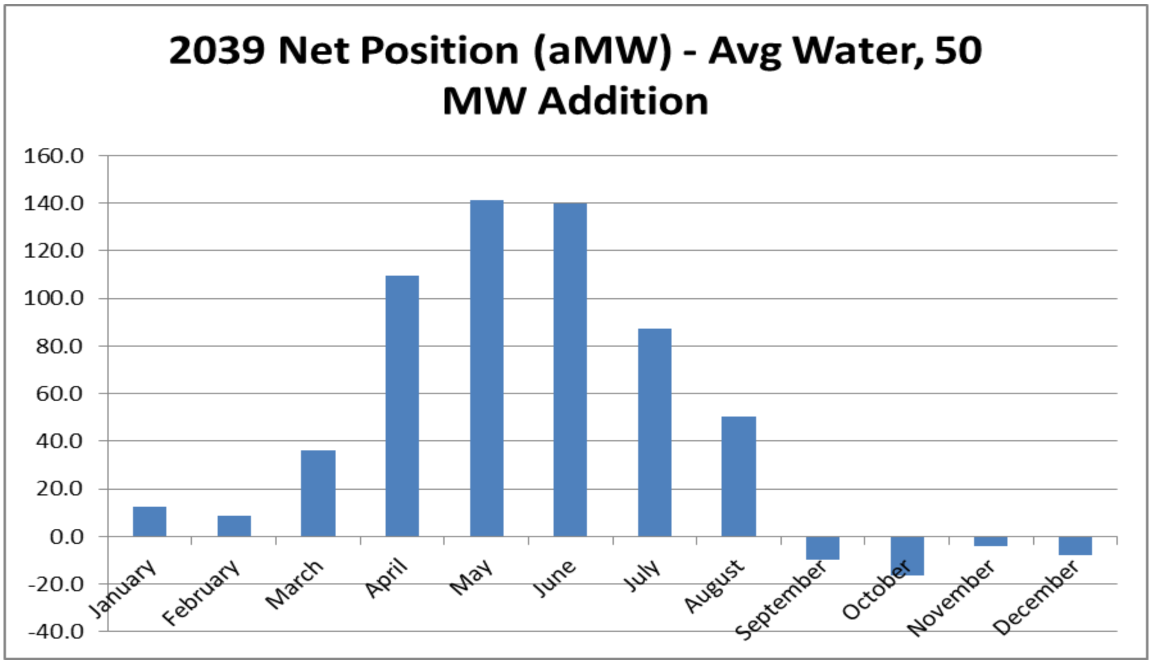


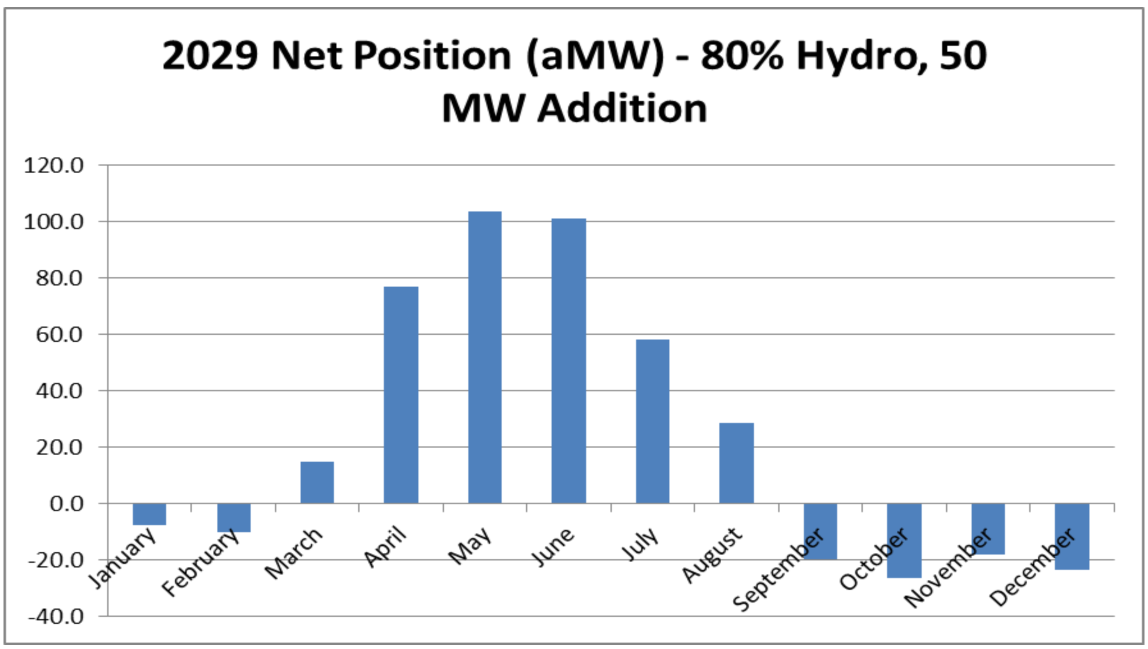
Following 2028, Okanogan may choose to operate without BPA power. This would impact the schedules the Distict completes each year with Okanogan staff. The net effect of this decision could make it such that the Okanogan is able to withdraw 30 percent of Wells (28.65%, net of the Colville share), which will put downward pressure on the District's share of Wells. The outlook for 2029 is materially down from 2028, just one year earlier. Increasing load out through 2029 puts the District in a potentially deficit position. Note that daily volumes vary, and even under prospective surplus conditions, daily deficits may manifest themselves during peak load events, or during periods of low inflow to Wells.

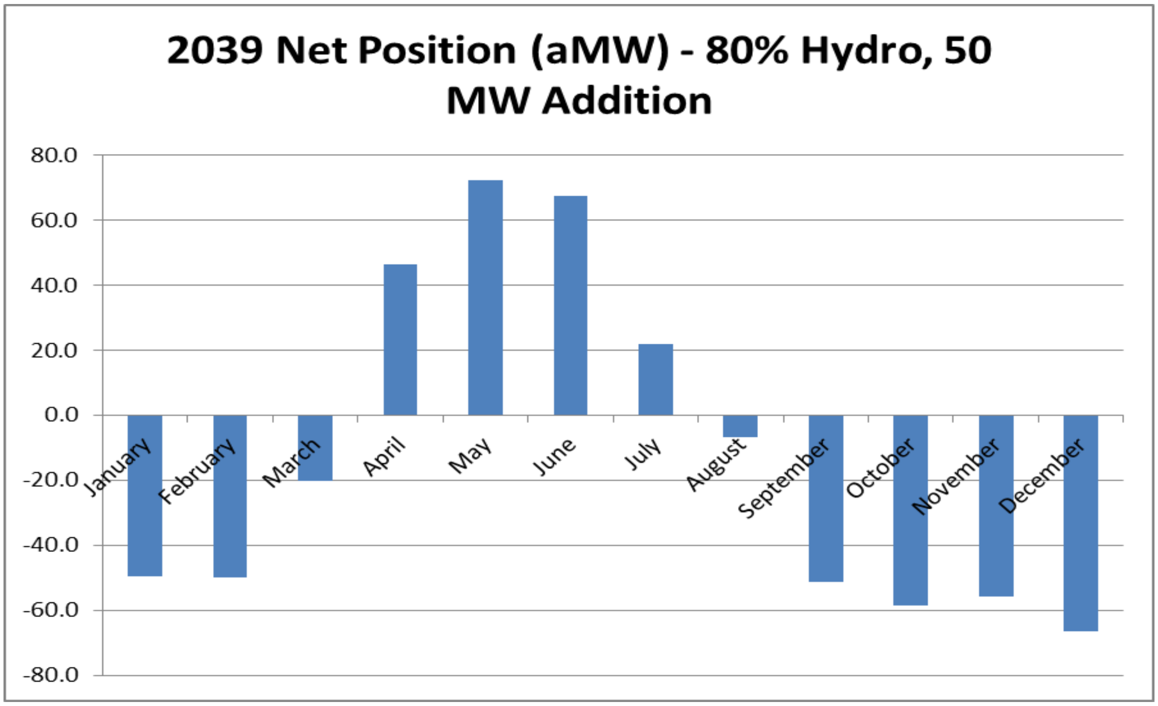




Several additional sensitivities were performed related to the addition of large loads. A sensitivity was performed in which 50 MW was added to the District's load profile at the beginning of calendar year 2021. The goal of this sensitivity was to determine the stress on the District's resources of adding a load or loads totaling that magnitude. As graphically represented below, even during average hydro conditions, the additions of such load produce a marginally negative net position beyond 2028. The potential deficits during an 80 percent hydro event are significant.


2039 Net Position (aMW) - Avg Water, 50 MW Addition
160.0
140.0
120.0
100.0
80.0
60.0
40.0
20.0
0.0
-20.0
-40.0
January
February
March
April
May
June
July
August
September
October
November
December


2029 Net Position (aMW) - 80% Hydro, 50 MW Addition
120.0
100.0
80.0
60.0
40.0
20.0
0.0
-20.0
-40.0
January
February
March
April
May
June
July
August
September
October
November
December

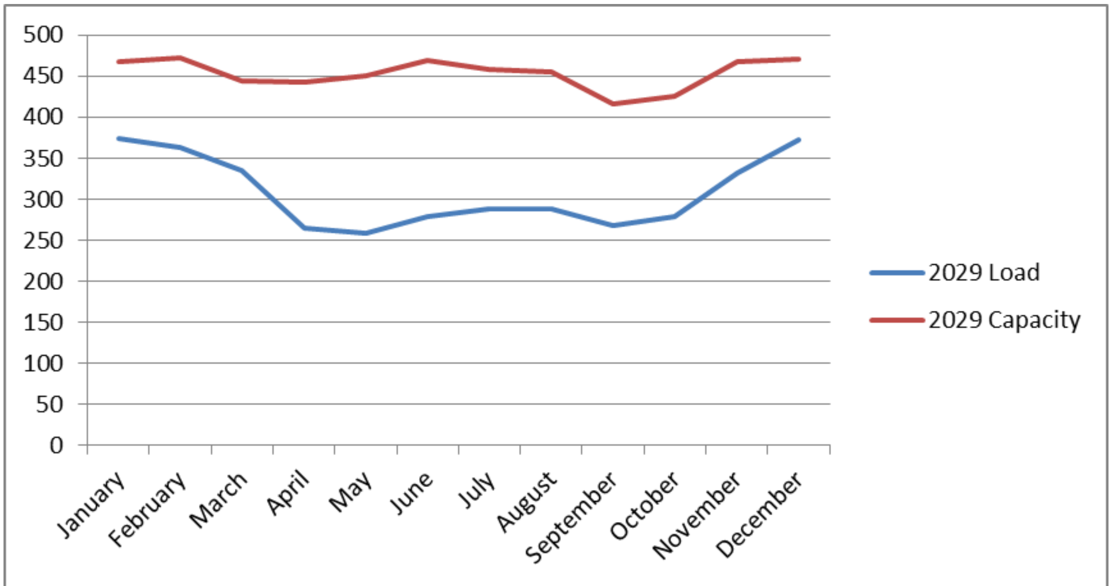


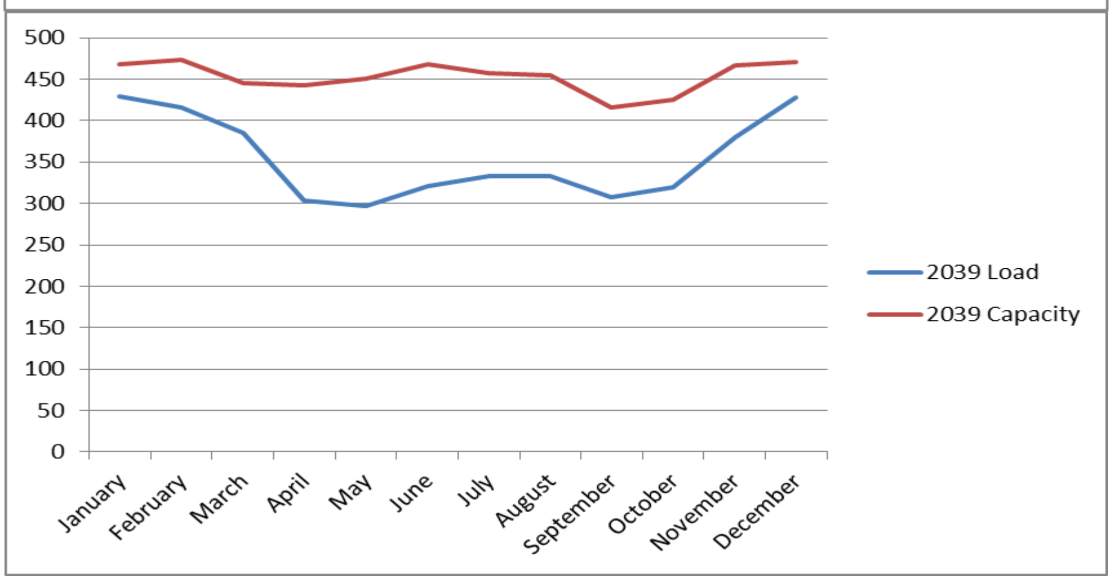
Tables containing the data graphically represented above are included in Appendix A.

Capacity Evaluation

Capacity was evaluated by month, with peak loading being represented by the highest expected hourly peak for any hour over the course of that month. This is a conservative look at capacity, as every other hour during the respective month will be lower than the peak value utilized for modeling purposes.

Since the District has significant firm capacity from its shares of Wells and Rocky Reach, and since the District does not have any wind or solar beyond 2030, it's not surprising that the District has more capacity than it has energy resources. This capacity is able to meet the expected hourly peaks in load. Below is a graph of expected hourly peaks for both 2029 and 2039, overlaid by expected capacity from the District's firm resources. Since the "50 MW" sensitivity is the most restrictive, this was the base case represented graphically. All other cases would produce a higher net position for the District.





Empirically, it can be seen that capacity available to the District is highest when load is also high. This is because the District's maintenance calendar follows the basic seasonal load shape of the District. This is expected to continue. Additionally, the District is engaged in an extensive generator and turbine overhaul project. Three units have been deemed completed, with either six or seven units to go. Using conservative modeling practices, it was assumed that the District will continue to be down a unit as a result of this rebuild effort for each period modeled, including the period of 2029-2039. The District would be in a surplus capacity condition in either scenario.

7.0 EVALUATION OF RESULTS

In a study released on August 7, 2019, titled, "Northwest March Price Spike Event," WECC provides guidance for utilities to ensure market stability. During the event analyzed, bulk wholesale prices reached $1,000/MWh. This guidance suggested that utilities should be situated to meet extreme weather events, especially since low or zero carbon state requirements could eliminate firm resources in the region. Meeting short-term needs in the bulk wholesale markets could prove challenging and expensive. It may not be possible.

In order to ensure the District has sufficient resources to meet its potential load obligations in 2029 and beyond, the District should explore several different options, as noted below.

- **Conservation** may nominally aid the District in its future load obligations. To date, the District has participated in a weatherization through the Chelan-Douglas Community Action Council. For 2017, MWh savings totaled .005 aMW. Conservation activities with a higher return on investment may exist within the county. Even so, much of the District's new load is in the form of non-diverse data, and such loads are not likely to be compatible with conservation activities.

- **Demand-response** in the form of load curtailment could help under certain circumstances. If an insufficiency of energy were limited to a day or series of days, and if such loads could be curtailed during this finite period of time, then demand-response will have provided a substitute for resource acquisition. It would not, however, resolve seasonal or monthly shortages, which is what is observed in Section 6.1 under certain scenarios. It should be noted again that the District is not expected to be capacity short, only energy short in the 10-to-20 year planning horizon, and curtailments typically resolve capacity issues. This IRP is strictly interested in resource adequacy, not economics, and no evaluation will be made with respect to the economics of demand-response curtailments.

- **Energy/Product Exchanges** could limit exposure to potential deficiencies during periods with less than average hydro conditions, while also taking advantage of the District's surplus capacity resources. The District has one such arrangement in place, and the modeling conducted above in Section 6.1 assumed that a perpetual 10 percent of Wells (net of the Colville obligation) would be exchanged for a firm block of power. The current arrangement has the District receiving 16 percent more energy from Avista than the District is providing to Avista by way of a slice product. Additional exchanges could take place on a term basis, in concert with annual and longer term planning activities.

- **Short-term Purchases** could augment shortages for shorter duration insufficiencies. Since the District's load projects are currently volatile and subject to significant uncertainty, there could be value in waiting to see what large loads materialize over the next five years. If needed, the District could enter into power sales for next-day insufficiencies all the way through the five-year planning horizon.

- **Joint or Sole Power Purchase Agreements (PPAs)** could be leveraged to meet expected demand on a longer-term basis. Solar and wind technologies have come down in cost, with the former providing somewhat more predictable output. Since the District has the Wells and Rocky Reach resources, and since it is potentially energy and not capacity deficient, it can more readily integrate such resources in a least cost fashion.

8.0 RECOMMONDATIONS

The District is surplus through 2028, at least on a modeling basis. No action needs to be taken immediately, but the District should explore additional resource alternatives as it looks beyond 2028. Under certain scenarios, the District may be short and require additional generating resources for the period beginning January, 2029. As noted in Section 9.0, below, procuring additional generating resource could prove more challenging and costly looking forward, and so additional effort should be taken in the near term to plan for all potential outcomes. Finally, it should be reiterated that the District does not typically plan to meet its load-resource balance based on average hydro conditions. For the purposes of this IRP, 80% of average water (inflow) into Wells and Rocky Reach was modeled as the condition on which the District should plan for meeting its prospective load obligations.

The options for consideration under Section 7 of this IRP are not mutually exclusive, and it is hereby recommended that the District explore each of them to some degree. The last option, entering into a PPA, should only be undertaken, however, if there is more certainty surrounding existing and future large load customers. Since potential deficiencies do not arise until calendar year 2029, it is recommended that in five years this IRP be revisited to better evaluate that option. Generating resources can take five years or more to plan, contract for, and build, and so this IRP should be updated no later than December 31, 2024.

With respect to Section 7, and as outlined more fully in that section, the District should focus on Energy/Product exchanges and short-term purchases, as necessary, through 2028. These alternatives show the most promise in allowing the District to meet its future obligations. At this time, conservation and demand response should be examined more closely to understand their potential within the District's service territory.

It's becoming increasingly apparent that utilities must be prepared for *tail risks* (those events with a small probability of occurring) as it relates to resource adequacy. With an evolution towards renewable generation which often lacks firm capacity, increased volatility will be felt regionally. This is exacerbated by the expected retirement of coal and natural gas plants. Prices will reflect this anticipated volatility, with greater periods of both oversupply and limited resources. A lack of native resources during a time of limited supply can result in load curtailments within a service territory.

Moreover, due to recent legislature in Washington State, clean fuel standards will require the District to increasingly serve customers with renewable resources, much of which must be owned. Serving load from bulk wholesale markets could prove economically impractical due to these new standards. In general, it is not advisable to rely on bulk wholesale markets for resource adequacy, particularly if deficiencies are expected to persist.

9.0 RESOURCE COST AND ENERGY FUTURE

One of the goals of an IRP is to assess the array of resources available, and particularly those resources which are renewable, to meet future energy needs. This is doubly important given the current landscape of energy regulations in the state of Washington.

Regulation

As noted in Section 4.3 of this IRP, Inslee signed a clean energy bill in 2019 with has a variety of requirements for utilities. Ultimately, it will require 100 percent of load to be served by renewable resources as of 2030, and in 2045 these resources must be owned. Therefore, the District will need to ensure it has sufficient native resources to meet load under all reasonable conditions by that date, and such native resources need to be renewable, as defined by this or any future legislation.

The District continues to be well situated to integrate renewable resources given its excess capacity from its share of Wells and Rocky Reach. Wind, however, can go dormant for long periods of time, and is not a good candidate to meet load on any sort of firm basis. Solar, on the other hand, has been the resource of choice for developers due to its declining cost and somewhat predictable generation pattern.

Solar Discussion

For several reasons, the District may want to consider solar if and when it’s in a position to evaluate the addition of generation to its resource stack.

Firstly, the Wells project has the ability to ramp 40 MW per minute which allows it to increase and decrease generation based on continuous set-points set by the District. This facilitates meeting load swings, but it also has the ability to integrate swings in other generation sources within its Balancing Authority Area (BAA), like solar.

Secondly, the Wells project has storage, much like a battery. The FERC license associated with the Wells Project allows for a ten foot range in operations, equal to 6,718 MWh of storage. This, too, allows the District to store water during periods of lower loading (or increased generation from other sources), or, conversely, generate the pool down during period of higher loading (and a lack of other sources of generation).

Finally, renewable sources like wind and solar do not often have the ancillary capabilities, like frequency response, the ability to carry reserves, and other key elements which are a requirement of a BAA. Because the District has a surplus of these ancillary capabilities at Wells, it can leverage these in order to facilitate additional renewable integration.

Many utilities rely on natural gas for integration, and the District’s unique volume of hydroelectric resources enables the District to more easily meet the new clean fuel standards. Nonetheless, despite these advantages, costs to add such resources will be greatly more expensive than its cost to operate Wells and pay for its share of Rocky Reach.

Geothermal Discussion

In the tables provided below, geothermal will appear cheaper than many alternative renewable options. Solar has been the popular choice for developers in the west. Geothermal generation should be explored, though caution should be taken, as it has not been as widely developed as solar. The reasons for that should be examined.

Cost Discussion

The EIA performed an evaluation in 2018 of the levelized cost of each major resource type. It should be noted that resources that can ramp up and down to integrate other resources and meet BAA standards have greater value than those resources which simply generate based on condition (wind, for instance, when its blowing), and so the costs reflected below should not be used to ascribe inherent value to any particular resource. Rather, it's simply a reflection of the cost per MWh of production. Additionally, the District needs to determine whether it's eligible to receive any of the tax credits figured into the EIA analysis, either by itself or through a public/private agreement.

Below are the results of the EIA evaluation for resources entering service in 2022. Also included is a table showing the range of costs regionally, and a longer-term outlook for 2040.

It should be noted that the impact to the District's transmission and distribution assets was not analyzed as part of this evaluation, nor was it considered when looking at the District's modeled load increases.

Table 1b. Estimated levelized cost of electricity (unweighted average) for new generation resources entering service in 2022 (2017 $/MWh)

Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmission cost	Total system LCOE	Levelized tax credit[1]	Total LCOE including tax credit
Dispatchable technologies								
Coal with 30% CCS[2]	85	84.0	9.5	35.6	1.1	130.1	NA	130.1
Coal with 90% CCS[2]	85	68.5	11.0	38.5	1.1	119.1	NA	119.1
Conventional CC	87	12.6	1.5	34.9	1.1	50.1	NA	50.1
Advanced CC	87	14.4	1.3	32.2	1.1	49.0	NA	49.0
Advanced CC with CCS	87	26.9	4.4	42.5	1.1	74.9	NA	74.9
Conventional CT	30	37.2	6.7	51.6	3.2	98.7	NA	98.7
Advanced CT	30	23.6	2.6	55.7	3.2	85.1	NA	85.1
Advanced nuclear	90	69.4	12.9	9.3	1.0	92.6	NA	92.6
Geothermal	90	30.1	13.2	0.0	1.3	44.6	-3.0	41.6
Biomass	83	39.2	15.4	39.6	1.1	95.3	NA	95.3
Non-dispatchable technologies								
Wind, onshore	41	43.1	13.4	0.0	2.5	59.1	-11.1	48.0
Wind, offshore	45	115.8	19.9	0.0	2.3	138.0	-20.8	117.1
Solar PV[3]	29	51.2	8.7	0.0	3.3	63.2	-13.3	49.9
Solar thermal	25	128.4	32.6	0.0	4.1	165.1	-38.5	126.6
Hydroelectric[4]	64	48.2	9.8	1.8	1.9	61.7	NA	61.7

[1]The tax credit component is based on targeted federal tax credits such as the PTC or ITC available for some technologies. It reflects tax credits available only for plants entering service in 2022 and the substantial phase out of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as *NA* or not available. The results are based on a regional model, and state or local incentives are not included in LCOE calculations. See text box on page 2 for details on how the tax credits are represented in the model.

[2]Because Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, two levels of CCS removal are modeled: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a 3 percentage-point increase to its cost of capital to represent the risk associated with higher emissions.

[3]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[4]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2018*.

Table B1b. Estimated levelized cost of electricity (unweighted average) for new generation resources entering service in 2040 (2017 $/MWh)

Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmission cost	Total system LCOE	Levelized tax credit[1]	Total LCOE including tax credit
Dispatchable technologies								
Coal with 30% CCS[2]	85	66.8	9.5	36.2	1.1	113.6	NA	113.6
Coal with 90% CCS[2]	85	54.5	11.0	35.8	1.1	102.4	NA	102.4
Conventional CC	87	10.4	1.5	40.6	1.1	53.6	NA	53.6
Advanced CC	87	11.3	1.3	38.0	1.1	51.7	NA	51.7
Advanced CC with CCS	87	20.0	4.4	50.4	1.1	75.9	NA	75.9
Conventional CT	30	30.6	6.7	60.3	3.1	100.8	NA	100.8
Advanced CT	30	17.7	2.6	61.2	3.1	84.7	NA	84.7
Advanced nuclear	90	54.4	12.9	9.8	1.0	78.1	NA	78.1
Geothermal	92	27.4	19.2	0.0	1.3	47.9	-2.7	45.2
Biomass	83	31.5	15.4	36.8	1.1	84.8	NA	84.8
Non-dispatchable technologies								
Wind, onshore	40	33.7	13.5	0.0	2.5	49.7	NA	49.7
Wind, offshore	45	88.2	19.9	0.0	2.3	110.4	NA	110.4
Solar PV[3]	29	40.1	8.7	0.0	3.3	52.1	-4.0	48.1
Solar thermal	24	103.6	33.7	0.0	4.2	141.4	-10.4	131.1
Hydroelectric[4]	61	42.9	9.4	4.1	2.0	58.4	NA	58.4

[1]The tax credit component is based on targeted federal tax credits such as the PTC or ITC available for some technologies. It reflects tax credits available only for plants entering service in 2040 and the substantial phase out of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as *NA* or not available. The results are based on a regional model, and state or local incentives are not included in LCOE calculations. See text box on page 2 for details on how the tax credits are represented in the model.

[2]Because Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, two levels of CCS removal are modeled: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a 3 percentage-point increase to its cost of capital to represent the risk associated with higher emissions.

[3]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[4]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2018*.

Table 2. Regional variation in levelized cost of electricity for new generation resources entering service in 2022 (2017 $/MWh)

	Range for total system levelized costs				Range for total system levelized costs with tax credits[1]			
Plant type	Minimum	Simple average	Capacity-weighted average[2]	Maximum	Minimum	Simple average	Capacity-weighted average[2]	Maximum
Dispatchable technologies								
Coal with 30% CCS[3]	117.2	130.1	NB	191.1	117.2	130.1	NB	191.1
Coal with 90% CCS[3]	110.5	119.1	NB	139.5	110.5	119.1	NB	139.5
Conventional CC	44.5	50.1	48.3	78.5	44.5	50.1	48.3	78.5
Advanced CC	43.5	49.0	48.1	76.8	43.5	49.0	48.1	76.8
Advanced CC with CCS	66.5	74.9	NB	84.8	66.5	74.9	NB	84.7
Conventional CT	87.2	98.7	NB	144.9	87.2	98.7	NB	144.9
Advanced CT	75.0	85.1	79.5	128.5	75.0	85.1	79.5	128.5
Advanced nuclear	89.7	92.6	90.1	97.5	89.7	92.6	90.1	97.5
Geothermal	41.7	44.6	43.1	49.5	39.2	41.6	40.3	45.8
Biomass	74.0	95.3	102.2	111.2	74.0	95.3	102.2	111.2
Non-dispatchable technologies								
Wind, onshore	40.7	59.1	48.0	77.3	29.7	48.0	37.0	66.2
Wind, offshore	122.2	138.0	124.6	168.5	103.8	117.1	106.2	142.3
Solar PV[4]	42.3	63.2	59.1	113.9	34.2	49.9	46.5	88.2
Solar thermal	145.1	165.1	NB	187.9	111.9	126.6	NB	144.3
Hydroelectric[5]	49.6	61.7	73.9	73.9	49.6	61.7	73.9	73.9

[1]Levelized cost with tax credits reflects tax credits available for plants entering service in 2022. See note 1 in Tables 1a and 1b.
[2]The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions in 2020–2022. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB* or not built.
[3]Because Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, two levels of CCS removal are modeled: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a 3 percentage-point increase to its cost of capital to represent the risk associated with higher emissions.
[4]Costs are expressed in terms of net AC power available to the grid for the installed capacity.
[5]As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.
Note: The levelized costs for non-dispatchable technologies are calculated based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are as follows: 37%–46% for onshore wind, 41%–50% for offshore wind, 22%–34% for solar PV, 21%–26% for solar thermal, 30%–79% for hydroelectric. The levelized costs are also affected by regional variations in construction labor rates and capital costs as well as resource availability.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2018*.

10.0 FUTURE EVALUATION OF THE IRP

Douglas PUD will review and update its resource plan approximately every five years or when a material change in conditions warrants a review. Since potential deficiencies are noted, and due to the volatility surrounding large load service and requests, this IRP should be updated prior to December 31, 2024.

Future evaluations of this process will assist Douglas PUD in achieving its mission:

"To provide the best possible utility services at the lowest possible cost, consistent with sound business principles."

11.0 APPENDIX A

Net Position by scenario (Energy Evaluation):

Average Hydro Conditions, Current Condition (aMW)												
	January	February	March	April	May	June	July	August	Septembe	October	Novembe	December
2020	243.3	230.6	247.2	322.0	364.2	372.7	312.0	262.7	172.0	166.4	202.6	217.6
2021	236.4	223.9	240.9	315.9	357.8	366.0	305.4	256.4	166.6	161.0	196.4	210.7
2022	228.8	216.7	234.2	309.2	350.8	358.6	298.2	249.6	160.8	155.1	189.7	203.3
2023	221.2	209.4	227.4	302.4	343.6	351.1	290.9	242.7	154.9	149.1	182.9	195.7
2024	213.0	201.5	220.0	295.0	335.9	342.9	283.0	235.2	148.6	142.8	175.5	187.6
2025	204.6	193.5	212.5	287.5	328.0	334.6	274.9	227.5	142.1	136.2	168.1	179.4
2026	195.7	185.0	204.4	279.4	319.4	325.6	266.2	219.3	135.2	129.3	160.1	170.5
2027	186.6	176.2	196.2	271.1	310.7	316.4	257.3	210.9	128.2	122.2	152.0	161.5
2028	176.9	166.9	187.4	262.3	301.3	306.5	247.7	201.9	120.7	114.6	143.3	151.9
2029	108.9	102.9	125.8	193.2	225.2	226.6	176.4	138.9	75.0	68.8	86.5	87.6
2030	102.7	96.9	120.1	187.9	219.9	221.0	170.5	133.1	69.7	63.4	80.6	81.3
2031	96.2	90.6	114.3	184.0	215.8	216.7	166.0	128.6	65.6	59.3	76.1	76.2
2032	91.1	85.7	109.7	179.8	211.6	212.1	161.2	123.8	61.3	55.0	71.3	71.0
2033	85.7	80.5	105.0	175.4	207.1	207.3	156.1	118.8	56.8	50.5	66.3	65.4
2034	80.1	75.0	99.9	170.8	202.3	202.2	150.8	113.5	52.1	45.7	61.0	59.7
2035	74.3	69.3	94.6	165.9	197.3	196.9	145.2	107.9	47.0	40.6	55.5	53.6
2036	71.8	67.1	92.9	164.8	196.2	195.5	143.6	106.4	45.8	39.2	53.6	51.1
2037	69.3	64.7	91.2	163.6	195.0	194.1	142.1	104.9	44.5	37.8	51.6	48.6
2038	66.7	62.4	89.4	162.3	193.8	192.6	140.5	103.4	43.2	36.4	49.6	46.1
2039	64.1	60.0	87.6	161.1	192.6	191.1	138.9	101.8	41.9	34.9	47.6	43.5

Average Hydro Conditions, 50 MW Sensitivity (aMW)												
	January	February	March	April	May	June	July	August	Septembe	October	Novembe	December
2020	243.3	230.6	247.2	322.0	364.2	372.7	312.0	262.7	172.0	166.4	202.6	217.6
2021	186.4	173.9	190.9	265.9	307.8	316.0	255.4	206.4	116.6	111.0	146.4	160.7
2022	178.8	166.7	184.2	259.2	300.8	308.6	248.2	199.6	110.8	105.1	139.7	153.3
2023	171.2	159.4	177.4	252.4	293.6	301.1	240.9	192.7	104.9	99.1	132.9	145.7
2024	163.0	151.5	170.0	245.0	285.9	292.9	233.0	185.2	98.6	92.8	125.5	137.6
2025	154.6	143.5	162.5	237.5	278.0	284.6	224.9	177.5	92.1	86.2	118.1	129.4
2026	145.7	135.0	154.4	229.4	269.4	275.6	216.2	169.3	85.2	79.3	110.1	120.5
2027	136.6	126.2	146.2	221.1	260.7	266.4	207.3	160.9	78.2	72.2	102.0	111.5
2028	126.9	116.9	137.4	212.3	251.3	256.5	197.7	151.9	70.7	64.6	93.3	101.9
2029	58.9	52.9	75.8	143.2	175.2	176.6	126.4	88.9	25.0	18.8	36.5	37.6
2030	52.7	46.9	70.1	137.9	169.9	171.0	120.5	83.1	19.7	13.4	30.6	31.3
2031	46.2	40.6	64.3	134.0	165.8	166.7	116.0	78.6	15.6	9.3	26.1	26.2
2032	41.1	35.7	59.7	129.8	161.6	162.1	111.2	73.8	11.3	5.0	21.3	21.0
2033	35.7	30.5	55.0	125.4	157.1	157.3	106.1	68.8	6.8	0.5	16.3	15.4
2034	30.1	25.0	49.9	120.8	152.3	152.2	100.8	63.5	2.1	-4.3	11.0	9.7
2035	24.3	19.3	44.6	115.9	147.3	146.9	95.2	57.9	-3.0	-9.4	5.5	3.6
2036	21.8	17.1	42.9	114.8	146.2	145.5	93.6	56.4	-4.2	-10.8	3.6	1.1
2037	19.3	14.7	41.2	113.6	145.0	144.1	92.1	54.9	-5.5	-12.2	1.6	-1.4
2038	16.7	12.4	39.4	112.3	143.8	142.6	90.5	53.4	-6.8	-13.6	-0.4	-3.9
2039	14.1	10.0	37.6	111.1	142.6	141.1	88.9	51.8	-8.1	-15.1	-2.4	-6.5

80% Hydro Conditions, Current Condition (aMW)

	January	February	March	April	May	June	July	August	Septembe	October	Novembe	December
2020	161.8	153.8	173.0	238.9	274.0	277.7	226.2	187.6	117.3	111.2	134.7	141.0
2021	155.3	147.6	167.3	233.3	268.1	271.5	220.1	181.7	112.2	106.1	128.9	134.6
2022	148.4	141.0	161.1	227.2	261.7	264.8	213.6	175.5	106.8	100.6	122.7	127.7
2023	141.3	134.2	154.7	221.0	255.2	258.0	206.8	169.1	101.3	95.1	116.3	120.7
2024	133.8	126.9	148.0	214.3	248.2	250.6	199.6	162.2	95.5	89.1	109.6	113.2
2025	126.1	119.6	141.1	207.5	241.1	243.0	192.3	155.2	89.5	83.1	102.7	105.6
2026	117.9	111.7	133.7	200.2	233.4	234.9	184.4	147.7	83.1	76.6	95.3	97.5
2027	109.6	103.7	126.2	192.7	225.5	226.7	176.3	140.0	76.6	70.1	87.8	89.2
2028	100.7	95.2	118.2	184.7	217.1	217.8	167.7	131.8	69.6	63.1	79.9	80.5
2029	46.7	44.4	69.3	129.8	156.4	154.2	111.0	81.6	33.4	26.7	34.7	29.3
2030	40.5	38.4	63.6	124.6	151.1	148.6	105.1	75.8	28.0	21.3	28.9	22.9
2031	34.1	32.1	57.8	120.7	147.1	144.3	100.6	71.3	24.0	17.3	24.3	17.9
2032	29.0	27.1	53.3	116.5	142.8	139.7	95.8	66.6	19.7	12.9	19.6	12.6
2033	23.6	21.9	48.5	112.1	138.3	134.9	90.7	61.5	15.2	8.4	14.6	7.1
2034	18.0	16.5	43.4	107.5	133.6	129.8	85.4	56.2	10.4	3.6	9.3	1.3
2035	12.1	10.8	38.2	102.6	128.6	124.5	79.8	50.7	5.4	-1.4	3.8	-4.8
2036	9.6	8.5	36.4	101.4	127.4	123.1	78.2	49.2	4.1	-2.8	1.8	-7.2
2037	7.1	6.2	34.7	100.2	126.2	121.6	76.7	47.7	2.8	-4.2	-0.1	-9.7
2038	4.5	3.9	32.9	99.0	125.0	120.2	75.1	46.1	1.5	-5.7	-2.1	-12.3
2039	1.9	1.5	31.1	97.8	123.8	118.7	73.5	44.6	0.2	-7.1	-4.2	-14.9

80% Hydro Conditions, 50 MW Sensitivity (aMW)

	January	February	March	April	May	June	July	August	Septembe	October	Novembe	December
2020	161.8	153.8	173.0	238.9	274.0	277.7	226.2	187.6	117.3	111.2	134.7	141.0
2021	105.3	97.6	117.3	183.3	218.1	221.5	170.1	131.7	62.2	56.1	78.9	84.6
2022	98.4	91.0	111.1	177.2	211.7	214.8	163.6	125.5	56.8	50.6	72.7	77.7
2023	91.3	84.2	104.7	171.0	205.2	208.0	156.8	119.1	51.3	45.1	66.3	70.7
2024	83.8	76.9	98.0	164.3	198.2	200.6	149.6	112.2	45.5	39.1	59.6	63.2
2025	76.1	69.6	91.1	157.5	191.1	193.0	142.3	105.2	39.5	33.1	52.7	55.6
2026	67.9	61.7	83.7	150.2	183.4	184.9	134.4	97.7	33.1	26.6	45.3	47.5
2027	59.6	53.7	76.2	142.7	175.5	176.7	126.3	90.0	26.6	20.1	37.8	39.2
2028	50.7	45.2	68.2	134.7	167.1	167.8	117.7	81.8	19.6	13.1	29.9	30.5
2029	-3.3	-5.6	19.3	79.8	106.4	104.2	61.0	31.6	-16.6	-23.3	-15.3	-20.7
2030	-9.5	-11.6	13.6	74.6	101.1	98.6	55.1	25.8	-22.0	-28.7	-21.1	-27.1
2031	-15.9	-17.9	7.8	70.7	97.1	94.3	50.6	21.3	-26.0	-32.7	-25.7	-32.1
2032	-21.0	-22.9	3.3	66.5	92.8	89.7	45.8	16.6	-30.3	-37.1	-30.4	-37.4
2033	-26.4	-28.1	-1.5	62.1	88.3	84.9	40.7	11.5	-34.8	-41.6	-35.4	-42.9
2034	-32.0	-33.5	-6.6	57.5	83.6	79.8	35.4	6.2	-39.6	-46.4	-40.7	-48.7
2035	-37.9	-39.2	-11.8	52.6	78.6	74.5	29.8	0.7	-44.6	-51.4	-46.2	-54.8
2036	-40.4	-41.5	-13.6	51.4	77.4	73.1	28.2	-0.8	-45.9	-52.8	-48.2	-57.2
2037	-42.9	-43.8	-15.3	50.2	76.2	71.6	26.7	-2.3	-47.2	-54.2	-50.1	-59.7
2038	-45.5	-46.1	-17.1	49.0	75.0	70.2	25.1	-3.9	-48.5	-55.7	-52.1	-62.3
2039	-48.1	-48.5	-18.9	47.8	73.8	68.7	23.5	-5.4	-49.8	-57.1	-54.2	-64.9

Net Position by scenario (Capacity Evaluation):

Current Loading (MW)												
	January	February	March	April	May	June	July	August	Septembe	October	Novembe	December
2020	335.8	352.1	338.7	398.1	414.2	419.6	397.1	392.8	358.5	361.5	370.9	340.6
2021	326.6	343.1	330.2	390.6	406.6	411.6	389.0	384.7	351.1	353.9	362.2	331.4
2022	316.8	333.3	321.0	382.3	398.3	402.8	380.1	375.9	343.1	345.6	352.9	321.5
2023	306.7	323.4	311.7	373.9	389.9	393.9	371.1	366.9	334.9	337.2	343.4	311.4
2024	295.9	312.6	301.6	364.8	380.7	384.2	361.4	357.2	326.0	328.1	333.1	300.5
2025	284.9	301.7	291.4	355.5	371.3	374.3	351.4	347.2	316.9	318.9	322.6	289.4
2026	273.1	290.0	280.4	345.5	361.2	363.6	340.7	336.6	307.2	308.9	311.4	277.5
2027	261.2	278.1	269.2	335.2	351.0	352.7	329.7	325.7	297.3	298.7	300.0	265.4
2028	248.4	265.4	257.2	324.3	339.9	341.0	318.0	314.0	286.6	287.8	287.7	252.5
2029	151.8	167.9	166.7	235.1	248.9	245.5	224.8	221.6	203.9	202.7	191.9	155.1
2030	144.1	160.3	159.5	228.9	242.8	238.9	218.0	214.8	197.7	196.4	184.8	147.3
2031	136.3	152.6	152.1	224.1	238.0	233.7	212.6	209.4	192.8	191.4	179.0	140.9
2032	129.7	146.2	146.0	219.1	232.9	228.3	206.9	203.7	187.6	186.2	173.0	134.3
2033	122.9	139.6	139.7	213.8	227.6	222.6	200.9	197.7	182.2	180.7	166.8	127.4
2034	115.8	132.6	133.1	208.2	222.0	216.5	194.6	191.4	176.5	174.9	160.2	120.2
2035	108.5	125.4	126.2	202.4	216.1	210.2	188.0	184.8	170.5	168.9	153.4	112.7
2036	104.7	121.9	123.1	200.5	214.4	208.1	185.8	182.6	168.6	166.7	150.4	109.0
2037	100.9	118.3	120.0	198.6	212.6	206.0	183.5	180.3	166.6	164.6	147.3	105.3
2038	97.1	114.6	116.8	196.6	210.8	203.9	181.3	178.0	164.6	162.4	144.2	101.5
2039	93.2	110.9	113.6	194.6	208.9	201.7	178.9	175.7	162.6	160.1	141.1	97.6

50 MW Sensitivity (MW)												
	January	February	March	April	May	June	July	August	Septembe	October	Novembe	December
2020	335.8	352.1	338.7	398.1	414.2	419.6	397.1	392.8	358.5	361.5	370.9	340.6
2021	272.5	289.0	276.1	336.4	352.5	357.4	334.8	330.5	297.0	299.7	308.1	277.3
2022	262.6	279.2	266.9	328.1	344.2	348.7	326.0	321.7	288.9	291.5	298.7	267.3
2023	252.6	269.2	257.6	319.7	335.7	339.7	317.0	312.7	280.7	283.1	289.2	257.2
2024	241.8	258.5	247.5	310.6	326.5	330.0	307.2	303.0	271.8	274.0	278.9	246.3
2025	230.8	247.6	237.2	301.3	317.2	320.1	297.3	293.1	262.8	264.7	268.5	235.2
2026	219.0	235.9	226.2	291.3	307.1	309.4	286.5	282.4	253.0	254.7	257.2	223.3
2027	207.0	224.0	215.0	281.1	296.8	298.6	275.6	271.5	243.1	244.6	245.8	211.3
2028	194.2	211.3	203.1	270.1	285.7	286.9	263.8	259.8	232.5	233.7	233.6	198.4
2029	97.6	113.7	112.5	181.0	194.8	191.3	170.7	167.4	149.8	148.6	137.8	100.9
2030	90.0	106.2	105.4	174.8	188.6	184.8	163.9	160.7	143.5	142.2	130.6	93.2
2031	82.1	98.5	98.0	170.0	183.8	179.6	158.5	155.2	138.6	137.2	124.9	86.8
2032	75.6	92.1	91.9	164.9	178.8	174.1	152.8	149.5	133.5	132.0	118.9	80.1
2033	68.8	85.4	85.6	159.6	173.4	168.4	146.8	143.5	128.0	126.5	112.6	73.2
2034	61.7	78.5	79.0	154.1	167.9	162.4	140.5	137.2	122.4	120.8	106.1	66.0
2035	54.3	71.3	72.1	148.2	162.0	156.1	133.9	130.6	116.4	114.7	99.2	58.5
2036	50.6	67.7	69.0	146.3	160.2	154.0	131.7	128.4	114.4	112.6	96.2	54.8
2037	46.8	64.1	65.9	144.4	158.4	151.9	129.4	126.2	112.5	110.4	93.2	51.1
2038	42.9	60.5	62.7	142.5	156.6	149.7	127.1	123.9	110.5	108.2	90.1	47.3
2039	39.0	56.8	59.5	140.5	154.8	147.5	124.8	121.5	108.4	106.0	86.9	43.5