McCullough Research

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Date: November 21, 2017

To: McCullough Research Clients

From: Robert McCullough

Subject: Updating Bonneville's Strategic Plan

On November 17, the Bonneville Power Administration presented a new strategic plan to its regional utility customers and other interested participants. The new plan did not focus on the root causes of mounting problems with competitiveness, operational inefficiency, reductions in borrowing authority, or cost control.

In this report, we offer some specific suggestions to Bonneville and to the region's utilities that are its customers:

1) Submit the Columbia Generating Station (CGS) nuclear power plant to a market test and, if it fails, close the CGS as rapidly as possible thereafter;

2) Re-engineer the Coordination Agreement and the Canadian Treaty to make it easier for the Columbia River's hydroelectric dams to meet the growing need to back up the variable resources of wind and solar energy; and,

3) Amend the 2008 power contracts to allow for additional loads, revenues, and jobs for the Pacific Northwest.

Introducing the new Strategic and Financial Plan at the public meeting on November 17, Bonneville Power Administrator Elliot Mainzer seemed to describe this short-term strategic plan very well when he said: "Strategy is important, but at the end of the day, culture eats strategy for lunch." BPA's conservative culture does not yet seem prepared to confront the changes in the industry.

As the presentation wore on, this short-term perspective raised questions from a number of utility executives in the room. One said: "I get this is only a short-term plan, but we're focused on 2028," when Bonneville's 20-year long-term power contracts are due for renegotiation. He went on to implore the BPA panel that "Ten years is not that far out" -- suggesting that good long-term planning can help BPA meet its short-term goals. BPA

Power Services Senior Vice President Joel Cook responded: "It's not that we're not thinking about it. It's just not a part of this process right now."

BPA needs to return to long-range planning -- what true strategic planning necessarily entails. In the 1930s, BPA's basic strategic plan was set out by J.D. Ross and a small staff with a clear focus on the distant future. Many things have changed over the eighty years that have passed since 1937, and the complexity of BPA's policy environment has grown enormously.

Instead, today's BPA has presented a plan where the only concrete details were found in its honest assessment of a need to reduce debt. After noting how proud BPA is to be one of the few utilities with a AA rating, it was noted that Fitch has placed them on a negative watch due to low reserve levels and high leverage. Fitch also noted that BPA faced a financial cliff in 2028 when its power rates may not be attractive enough for its long-term customers to renew 20-year contracts.

The strategic plan was presented as a call to action, but few operational details were offered to explain how BPA's financial position might be improved. The debt ratio of its power business is currently around 100%.

The other goal is to increase the power unit's "Days Cash on Hand" metric to 60 days from the current level of zero days of cash available. All of this comes at a time when, if current trends continue, BPA will deplete its legal borrowing authority from $2 billion to $750 million in the next 5 years.

Meeting these goals will require the accumulation of $300 million in additional reserves. Based on the last rate case this will take 15 years to accomplish. This strategic plan is mostly about short-term financial tactics to reach a sustainable debt ratio and cash on hand before they deplete their borrowing authority and get downgraded by rating agencies.

As recently as twenty years ago, the governors of Idaho, Montana, Oregon, and Washington convened a blue-ribbon panel, attempting to address the cost pressures of the northwest's only nuclear plant and the challenges caused by the competitive market. The agreements forged then, including the market test for closing the Columbia Generating Station (CGS), were forgotten in the disaster caused by a manipulated market in the Enron scandal, but are now, once again, pertinent, as will be outlined in this report

Cost Control, Improved Operations, and Market Expansion

BPA is at a pivotal moment, facing enormous challenges in three critical areas: controlling its rapidly increasing costs, operating the region's hydroelectric system to its best advantage, and marketing the energy it has to sell in ways that will continue to attract customers. All three of these challenges will require re-examining the "business as usual" model BPA has adopted in recent years.

Cost control must include eliminating costly purchases, including the previously untouchable Columbia Generating Station nuclear power plant. Operational improvement must emphasize the strength and flexibility of the region's hydroelectric system to back up growing wind and solar resources, and build upon it with updated agreements that allow the Northwest to benefit from underutilized storage capacity in Canadian reservoirs. Marketing changes must recognize that remaining competitive with other regions and nations will require flexible pricing schemes. We will outline the problem, then address these three issues in reverse order.

BPA's Most Immediate Challenge: Addressing the Long-term Decline in Energy Prices

At the heart of the problem is a combination of a long-term drop in the price of natural gas brought on by the introduction of new methods of gas extraction and a rapid improvement in the technology of producing and delivering electric energy from renewable resources. Lazard, the investment house that publishes an economic study of generation alternatives, has reported that the renewables are overtaking traditional generation choices:

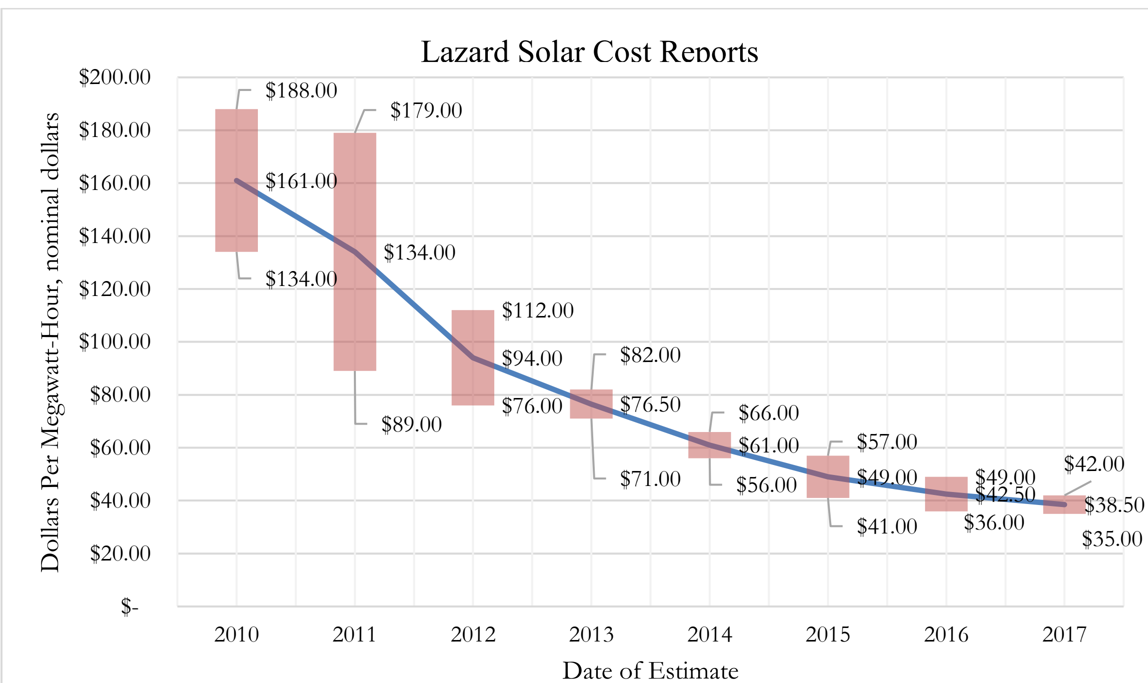

Figure 1: Levelized Cost of Energy for Solar (Lazard Historical Estimates)

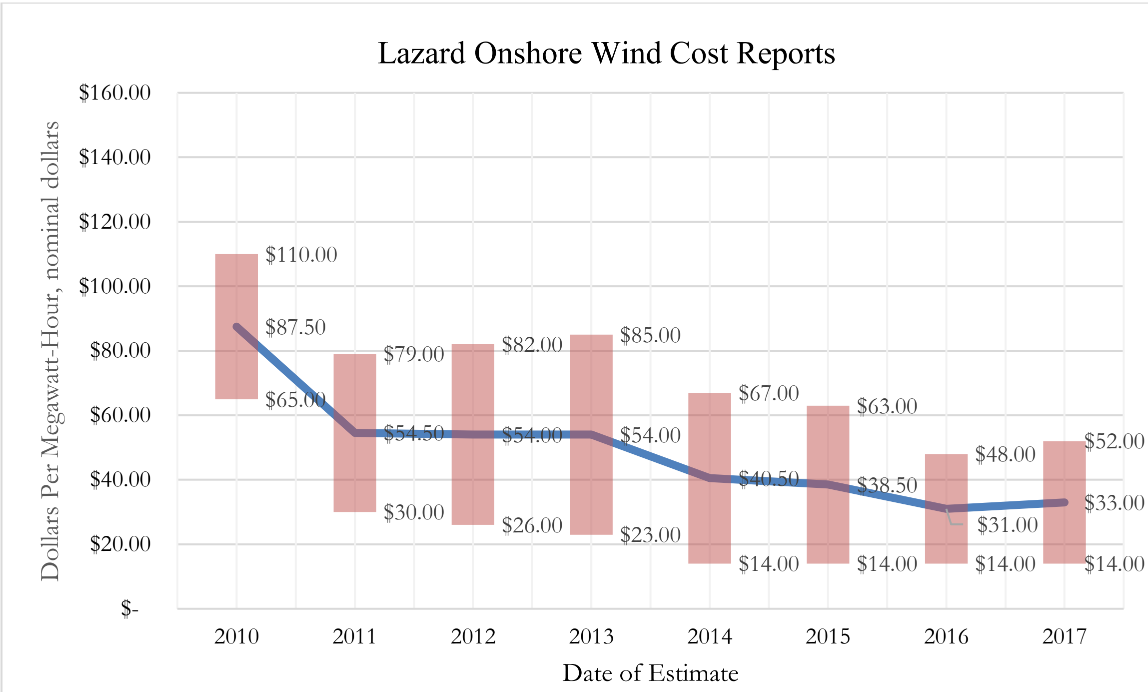

Figure 2: Levelized Cost of Energy for Wind (Lazard Historical Estimates)

The shift in economics has been accentuated by environmental concerns that have mandated solar and wind investments across the west coast. Increasing the market share of renewables has impacts beyond the levelized cost of energy. It is also changing the supply curve in the market for energy.

The world's oldest and best-established market hub for electricity is in the Pacific Northwest at Mid-Columbia. Prices have plummeted in recent years as we introduced massive amounts of renewables and gradually started to replace high-priced coal resources. The new resources have zero marginal cost; so, the supply curve for energy is moving to the right, lowering prices significantly.

The following chart gives an overview of wholesale prices and BPA rates for the last twenty years:

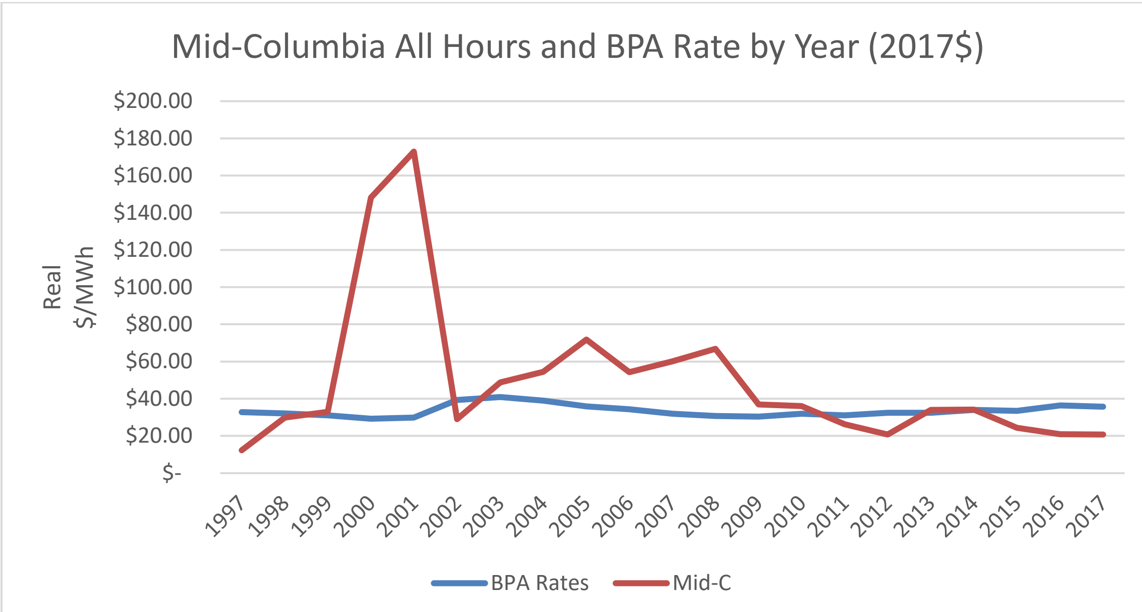

Figure 3: Mid-Columbia Prices and BPA Rates

Most analysts attribute Mid-Columbia prices to the burgeoning supply of natural gas in North American markets. The very deep forward market for natural gas at Henry Hub in Louisiana is expected to be stable over the next decade. In fact, prices for the next few years are expected to continue to decline.

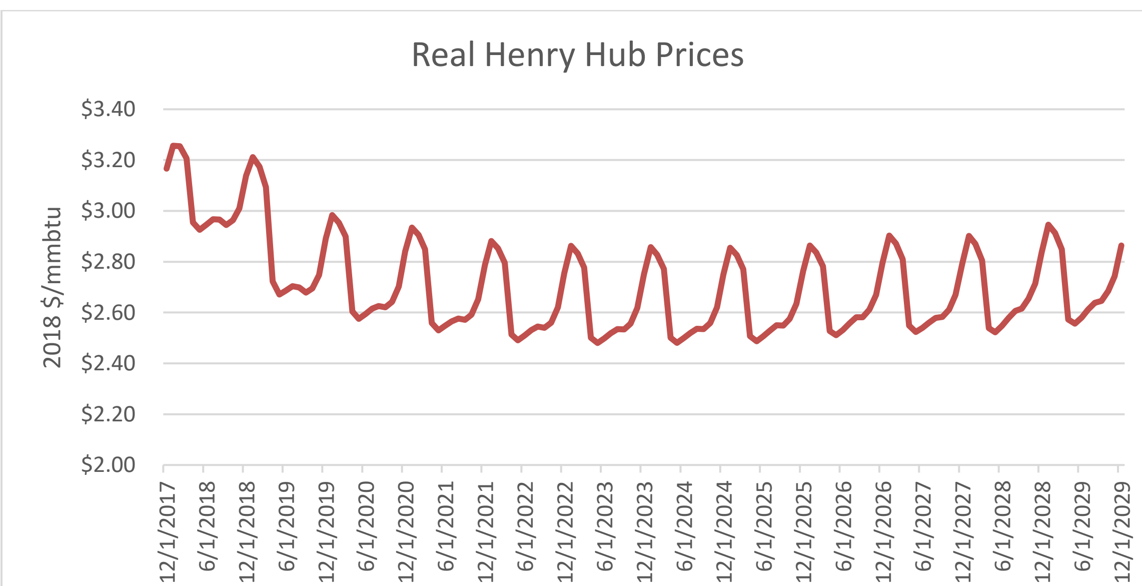

Figure 4: Real Henry Hub Prices

The situation today is actually more severe than the price concerns that led the region to establish a CGS market test twenty years ago. The introduction of LED lighting and other energy efficiency measures, along with large reductions in the region's manufacturing base, have brought load growth to a halt in many jurisdictions. This year's market prices at the Mid-Columbia hub were the lowest in history and forward prices for the next two years are even lower.

In addition, the increase in zero marginal cost renewables has significantly changed the region's supply curve and lowered market prices. In the charts below, additional renewables lower the market price (the dashed line) from $25/MWh to $15/MWh:

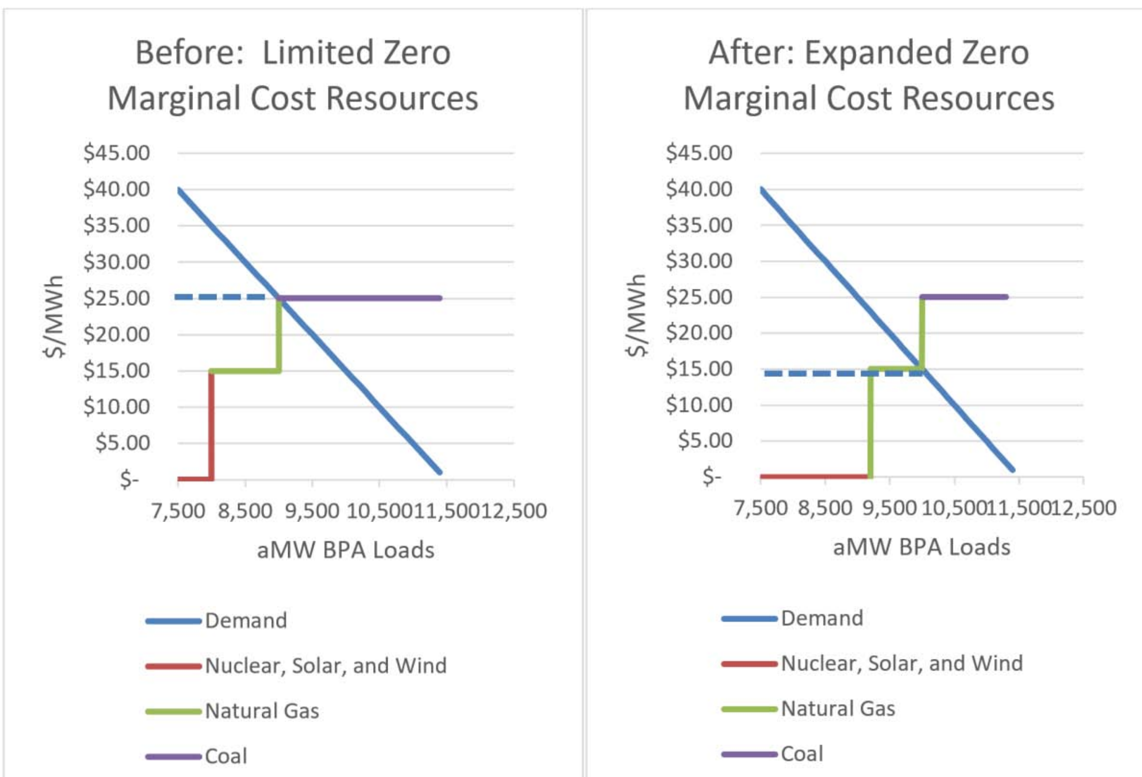

Figure 5: Impact of Renewable Resources

When additional zero marginal cost resources are added, the entire supply curve moves to the right. This lowers Mid-Columbia prices – even when the costs of other generating units stay the same. Wind and solar's zero marginal cost generation has already begun reducing prices to levels even lower than those dictated by falling natural gas prices.

BPA's basic costs are dominated by past nuclear investments and are very difficult to reduce. In addition, the decision to allow roughly $100 million of annual CGS Operations and Maintenance costs to be financed with Energy Northwest bond sales further obligates Bonneville to decades of repayment and reduces its already challenged borrowing authority.[1] Finally, BPA has signed a series of contracts with its major customers that tend to exacerbate their market presence and hobble their ability to compete.

Adjusting Industrial Rates to Reflect the Market

From time to time, BPA has provided market expansion rates to some customers – most notably the Intalco aluminum smelter at Ferndale, Washington.[2] Unfortunately, the agency tends to approach business problems primarily as posing political questions – rather than leading to business answers.

This means that, due to BPA's uncompetitive single price for all products market strategy, full price purchases from BPA have been declining. Its primary customer base is down by 6% this year.

It's time for BPA to diversify its marketing strategy, using price differentiation. The most common example is that of large companies like Nordstrom which have flagship stores in major cities and discount stores (Nordstrom Rack) in other locations. Nordstrom has differentiated their market segments to serve different groups of customers.

In BPA's case, they have already done this for the Intalco aluminum plant. In order to get the lower market rate, the customer had to meet a benefits test to establish that BPA's net revenues were enhanced by the market price contract.

Since the Mid-Columbia market hub has a large surplus at increasingly low prices, the optimal solution would be for Bonneville to adopt a market expansion rate for new industry and to provide opportunities to maintain production at existing industries.

[1] Marcus Harris, Senior Policy Advisor, Finance, Bonneville Power Administration – in answer to question regarding annual O&M costs of CGS – BPA's Strategic and Financial Plans, Public Meeting, 11/17/17
[2] An analysis of the Intalco contracts is attached to this memo.

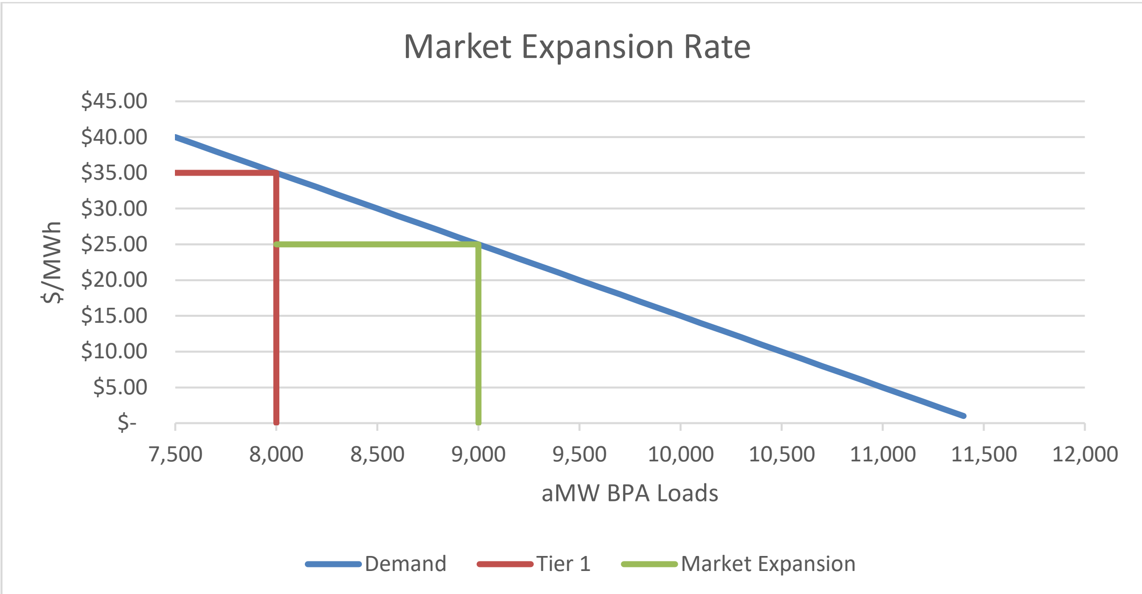

Figure 6: Market Expansion Diagram

Tier 1 power is higher priced and gets higher priority. Encouraging industrial development was a major part of BPA's core mission when it was established during the New Deal. For decades, Bonneville provided lower cost power to Direct Service Industries, as they were called, mostly consisting of aluminum smelters, who agreed to be subject to power interruption in high demand periods in return for their lower rates.

In preliminary talks with a number of BPA's primary customers, it is clear that allowing them to compete for new industrial loads would be welcomed. And since the precedent has already been established, it would be relatively easy to implement.

The resulting contracts that would come from this adjustment of BPA contracting policy would work well for all parties. BPA can set the market expansion rate above the current market by a small margin. Each new load that meets the benefits test would add to BPA's net revenue. The benefits test protects BPA from revenue erosion since the market price transactions would only be offered to new or at-risk industries.

Adjusting Hydro Operations to the Twenty-first Century

In 1948, Oregon's second largest city was destroyed in the Vanport flood. The specter of this disaster dominated the negotiations that created the coordination agreement between the hydro-electric dam operators along the Columbia and the Canadian Treaty.

In 1964, the Canadian Treaty and the Coordination Agreement were both adopted. The Coordination Agreement was revised in 1997, and, as is also the case for the Canadian Treaty, 2024 is the looming critical date for renewal.

The Canadian Treaty has been the subject of sporadic attempts at renegotiation for several years. Both agreements reflect the concerns of 1948 and 1964. It is unclear how suited they are for 2017. The question is whether storage, the most valuable product the Columbia River dams currently produce, needs to be specifically addressed with significant improvements to the Coordination Agreement and the Canadian Treaty. Storage is not configured as a product, but storage is a critical component of a renewables-based resource future.

Figure 7: Map of dams along the Columbia river

The central issue is that the primary reservoirs are on the Canadian side of the border. The vast majority of the generation is in the United States. Coordination between the Canadian reservoirs and U.S. turbines is a complex problem. The existing agreements reflect the priorities of the sixties when the most valuable product was energy. This is no longer the case. Today, the most valuable product is storage – specifically storage needed to firm up renewables. BPA's strategy should be to use hydro power not only as a primary source of electricity, but to expand its use as a backup for the intermittency of wind and solar generation.

BPA provides data on wind generation in five-minute increments. For 2016, we can see how many megawatt-hours it would take to firm the 4,782 MW of wind in their control area over one year. The following chart shows the actual wind generation for twelve-time increments in each hour. Charted in orange is the draw on the region's reservoirs.

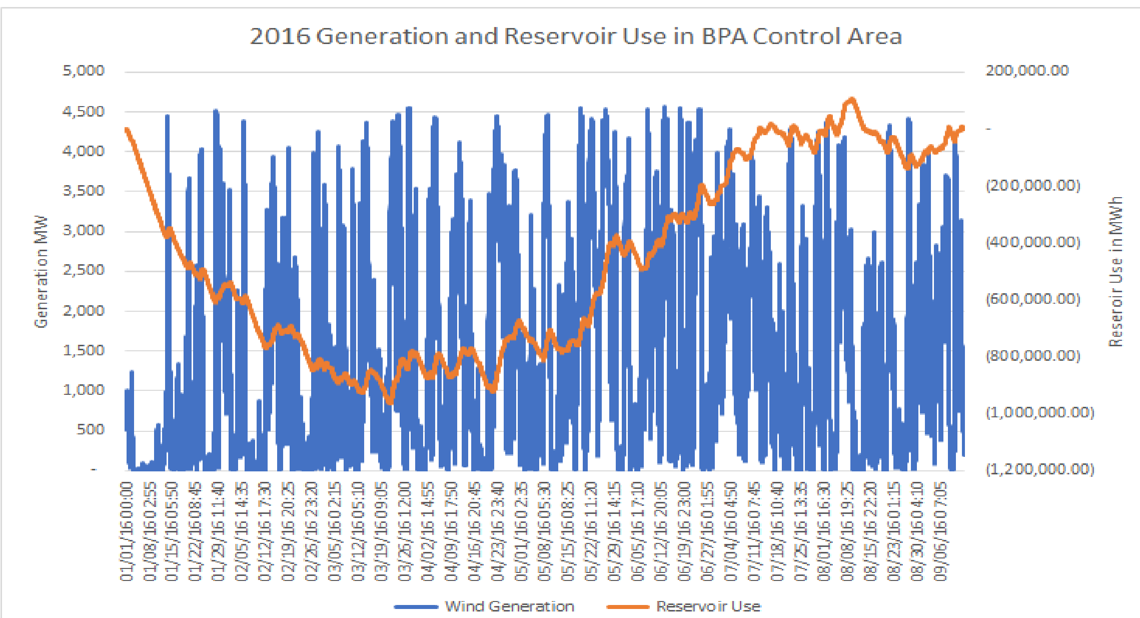

Figure 8: Wind Storage in the BPA Control Area

The maximum draw on the reservoirs came at 6:45 P.M. on March 21, 2016. At that point, if the system wanted to maintain a minimum generation level of 1,414 MW from wind, the reservoirs would have been tapped for 986,235 megawatt-hours. After that date, the reservoirs would gradually refill, allowing it to back up the intermittency of renewable resources.

This "ideal world" of maximizing the operation of the Columbia's hydroelectric system for backing up variable resources is constrained by the need to operate dams for other purposes, most notably flood control and fish survival. The dams from Grand Coulee and above into Canada do not have any fish passage and are, therefore, most useful in responding to variable resource demands on the Northwest grid. This makes concluding favorable agreements with Canada all the more important, allowing Bonneville to maximize load using the storage capacity of the large Canadian dams.

The widely-publicized decline in solar and wind prices now makes it probable that CGS could be replaced entirely with renewable resources and still deliver a cost reduction to Pacific Northwest customers. Once thought to be too expensive, renewables have become a viable option for utilities, as demonstrated by last year's agreement between Pacific Gas & Electric, its unions, and environmental organizations to phase out and replace California's Diablo Canyon Nuclear Station's output with renewables.

Experience in integrating these variable resources has grown. Indeed, as renewable energy standards in the Pacific Northwest, California, and other Western states require additional variable resources, inflexible baseload plants, including nuclear and coal plants, will become increasingly problematic. Renewable portfolio standards (RPS) have mandated increases in utilities' mix of renewable resources. Oregon's Renewable Energy Act of 2007, which established its RPS, was updated in 2016 to require 50% of generation from renewables by 2040.[3] Washington passed its RPS, Initiative 937, by ballot in 2006. It requires utilities serving more than 25,000 customers to generate at least 15% of their energy from renewables by 2020.[4] California's RPS mandates 50% renewable energy by 2030. Both Oregon and California have increased the initially legislated standards over time.

Using renewable energy cost estimates from the financial advisory firm Lazard, and comparing them against Energy Northwest's own projected cost of power, the net present value benefit of replacing CGS with a solar and wind portfolio is estimated to be $261.2 million over a ten-year period.[5,6,7]This is a conservative estimate, as the benefit could be significantly higher. Since 2007, CGS's actual cost of power has been 19.2% higher than the projections set out in Energy Northwest's Long-Range Plans; when accounting for this

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[3] This applies to investor-owned utilities, municipal utilities, cooperative utilities, and retail suppliers.
[4] Database of State Incentives for Renewable Energy (DSIRE). "Renewable Portfolio Standard: Washington". June 7, 2017. Accessed November 15, 2017. <http://programs.dsireusa.org/system/program/detail/2350>.
[5] Lazard. "Levelized Cost of Energy Analysis – Version 11.0." November 2017. Accessed November 10, 2017. <https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf>. This calculation uses the median cost, with federal tax credits, for utility-scale solar and onshore wind, at $42.50 and $31/MWh, respectively. See page 4 of the Lazard report.
[6] Energy Northwest. "Finance and Long-Range Planning." Accessed November 15, 2017. <https://www.en-ergy-northwest.com/whoweare/finance/Pages/default.aspx>.
[7] The assumed discount rate for this calculation is 13%. This is the discount rate that Bonneville Power Administration (BPA) uses for power investments.

discrepancy, the net present value benefit of replacing CGS with solar and wind power could be as high as $530.7 million for the same period (see Figure 9).

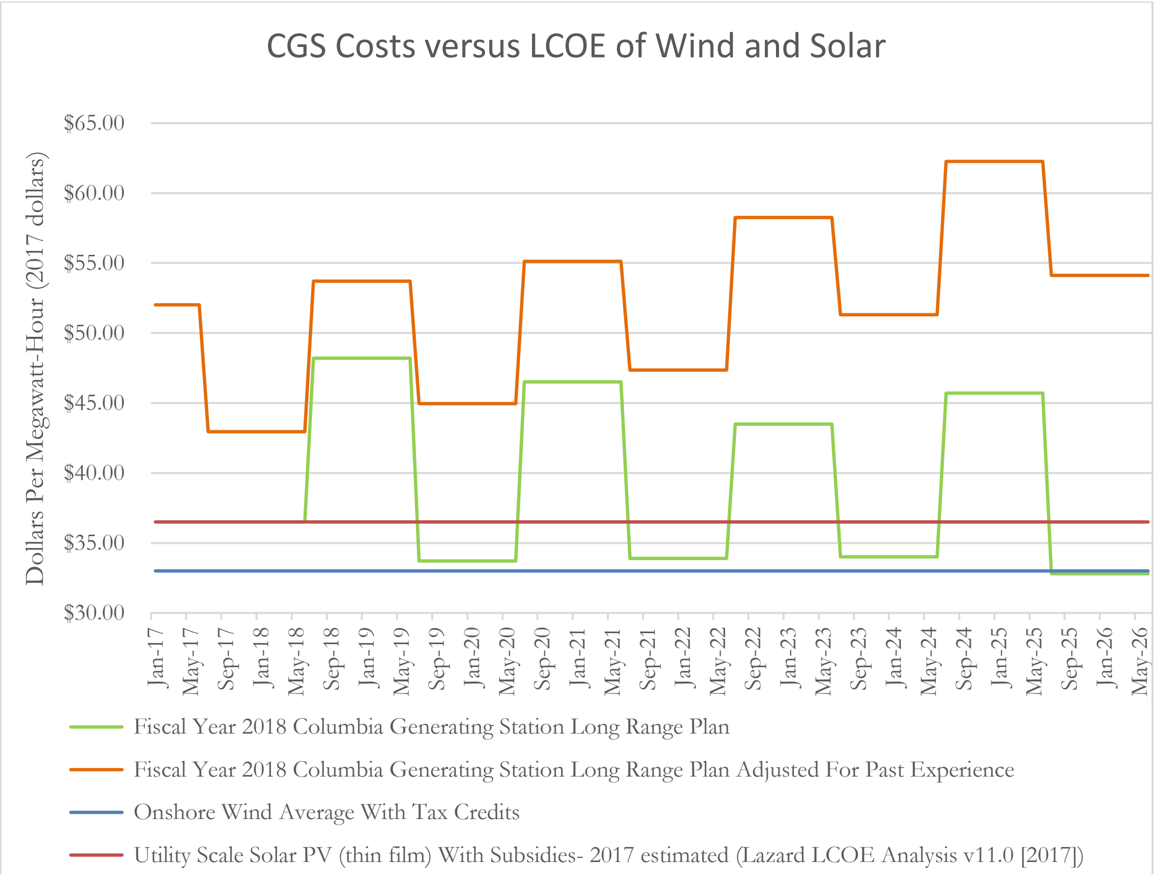

Figure 9: CGS Costs versus LCOE of Wind and Solar

Wind generation is a more mature technology compared to solar PV. In 2016, wind generation in the U.S. totaled 226,872 GWh, representing 5.6% of all electricity generation.[8] In recent years the cost of onshore wind generation has declined steeply. According to the annual analysis by Lazard, the midpoint of onshore wind's LCOE fell from $87.50 to $33.00/MWh over the 2010-2017 period, a 62% decline.[9] We can expect increasing demand for storage and, consequently, an increasing value to be placed on Columbia River reservoirs.

[8] EIA. "Electric Power Monthly with Data for June 2017." August 24, 2017. <http://www.eia.gov/electricity/monthly/>.
[9] Lazard. "Levelized Cost of Energy Analysis – Version 11.0." November 2017. Accessed November 10, 2017. Page 3.

Eliminate Bonneville's Most Costly Resource

Twenty years ago, operating WPPSS-2 (now Columbia Generating Station or CGS) required 7% of BPA's total revenues. This year the value has risen to 13%. The problem is the unfortunate nature of the costs of aging generating units to increase more rapidly than inflation. This is salient for nuclear units, which face extreme heat and radiation related stress to aging equipment and repairs within radioactively contaminated areas which pose special and very expensive challenges.

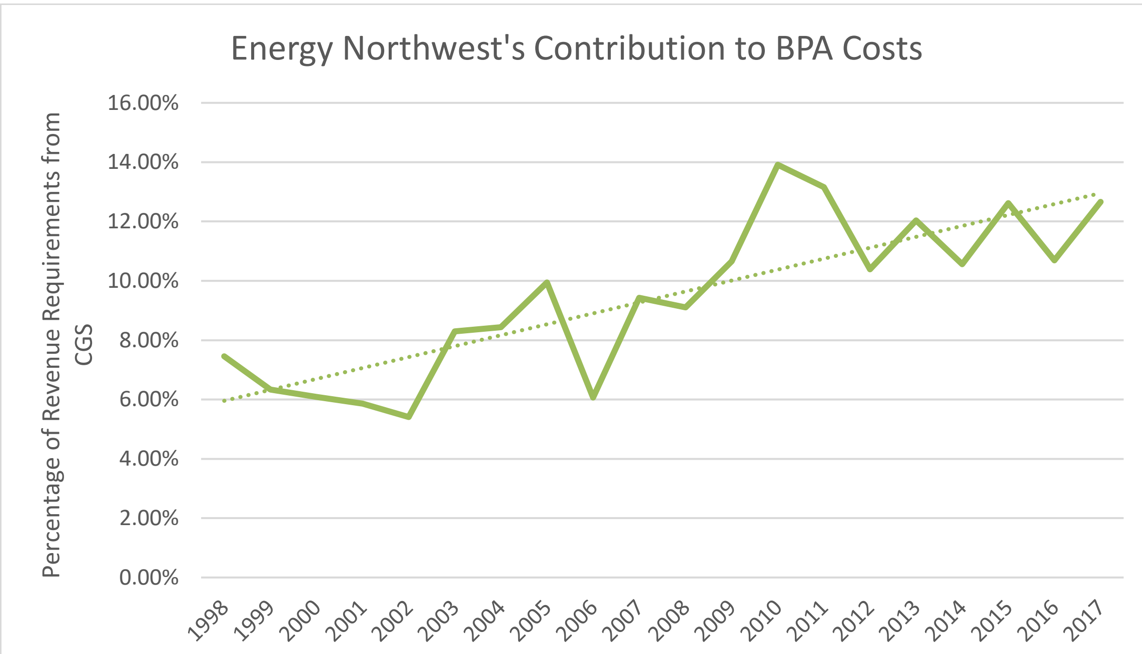

Figure 10: Energy Northwest's Contribution to BPA Costs

Although the causes of the increasing pressure on BPA's finances are more complex than a simple trend, it is useful to see that year by year, the Columbia Generating Station has increasingly dominated BPA's economics, Earlier this year, Energy Northwest described a nightmare scenario in which BPA rates gradually increased to CGS levels.[10] The scenario is extremely alarming since it implies that BPA rates would increasingly diverge from the competitive markets that are open to its primary customers.

To give an idea of this problem's scale, during Energy Northwest's Fiscal Year 2017, the

[10] Columbia IPR 2 and Cost-effective Operation, Brent Ridge and Kent Dittmer, February 15, 2017, slide 10.

Mid-Columbia market price of energy was $21.55/MWh.[11,12] The operating cost of the Columbia Generating Station was $50.40/MWh, forcing BPA to purchase 8,640,000 MWhs from Energy Northwest at $50.4/MWh to sell the power at an average price of $21.55/MWh – a $249 million loss.

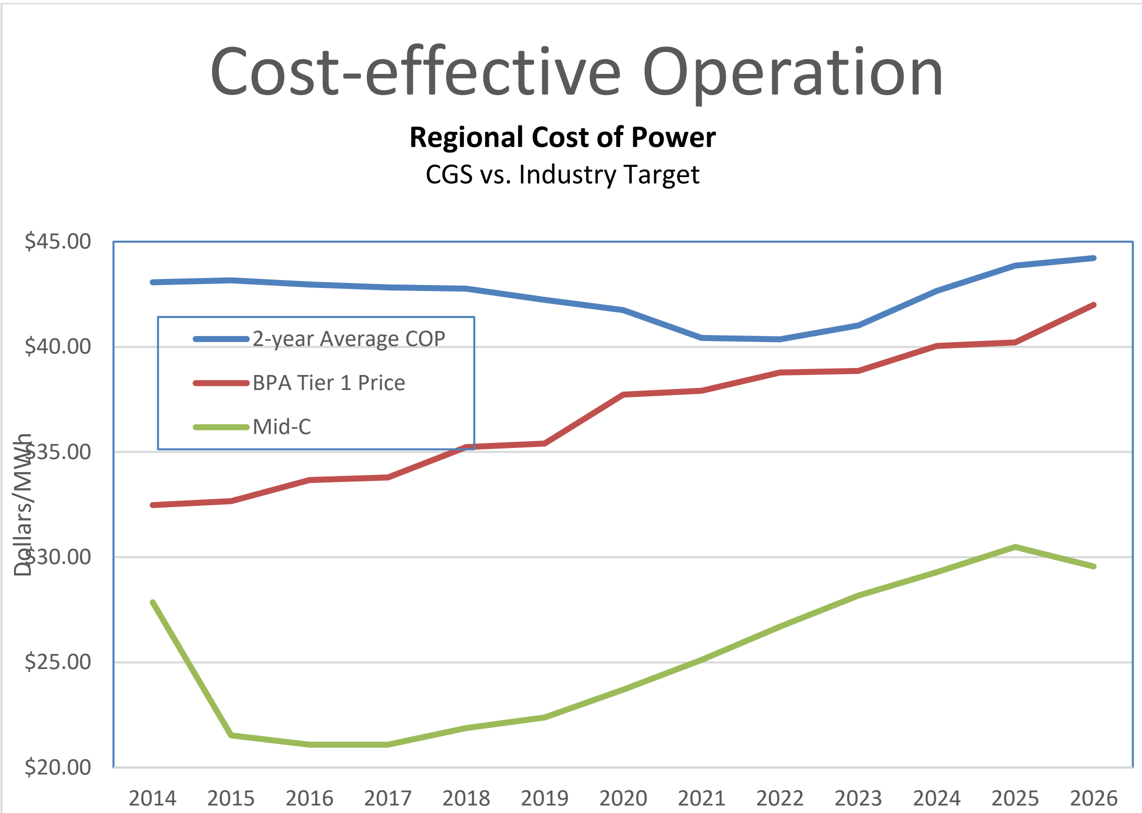

Figure 11: Cost-effective Operation

Figure 11 above adds the forward price of energy at Mid-Columbia. As can clearly be seen, even these optimistic forecasts (the blue line) will keep the Columbia Generating Station as a major financial burden for many years to come. In the rest of the industry, nuclear plant costs have been increasing with the age of the unit. Therefore, this chart, using Energy Northwest's CGS cost projections, as bad as they look compared to the projected competitive cost of power, most likely portrays an unrealistically optimistic vision of the future.

[11] Platts daily Electricity Report. Jan 1, 2017 – November 13, 2017
[12] CME Mid-C Peak Forwards. November-December 2017

One way that Energy Northwest's O&M numbers have been kept lower, though not low enough to be competitive, has been through the decision to allow reactor costs to be financed by debt – roughly $100 million per year financed by bond sales.[13] The ongoing borrowing for operations and maintenance costs of the CGS contributes to Bonneville's continuing challenges regarding high debt ratio and depletion of borrowing authority.

BPA has been wary of the CGS' costs before. In 1998, during the course of the aforementioned extensive regional review of costs and policies, the cost-review committee of the Comprehensive Review recommended that CGS be measured against market prices:

> Washington Nuclear Plant 2: Combine aggressive cost management with a flexible response to market conditions and unforeseen costs. Manage annual operating costs to annual revenues achievable at market prices. Sell a portion of Bonneville's power, equal to the output of CGS, at a price that will recover the plant's operating costs. Test the plant's power prices against market prices every two years, and evaluate terminating the plant if projected operating costs exceed projected revenues. If revenues exceed costs, use a portion to build a decommissioning fund. Estimated annual savings: $19 million.[14]

BPA accepted the recommendations.

> The BPA Proposed Plan:
>
> BPA agrees with the basic objective of the Cost Review recommendation, "to ensure that the operations of the plant not be insulated from the discipline of the marketplace" and to achieve the recommended increase in net operating revenues.
>
> BPA intends to subject CGS operating costs to a market test biennially, testing whether market value of the CGS output recovers annual operating costs of the plant. BPA intends to solicit input on the precise nature of this market test in a public process this year.
>
> Likewise, as recommended in the Review, BPA intends to re-evaluate plant termination if operating costs are projected to exceed revenues achievable at market prices by more than the termination costs.

[13] Marcus Harris, Senior Policy Advisor, Finance, Bonneville Power Administration – in answer to question regarding annual O&M costs of CGS – BPA's Strategic and Financial Plans, Public Meeting, 11/17/17
[14] Northwest Power and Conservation Council. *Issue brief no. 98-10. 1998 Briefing Book*. Nwcouncil.org. May 1998. Web. 15 Oct. 2013. <http://www.nwcouncil.org/reports/1998/98-10>.

> With the cost and revenue projections assumed by the Cost Review, this would require about $19 million of operating cost reductions and/or revenue increases. BPA will work with the Supply System to achieve as much of this enhancement of net revenues as possible through reductions in operating costs.
>
> BPA intends to work with the Supply System to achieve additional operating cost efficiencies, avoid major capital additions, shorten outages, and, potentially, change from an annual to a biennial refueling cycle (would reduce from 5 to 2 the number of refuelings during next 5-year rate period).
>
> Cost reductions assume, in part, that there are no major equipment failures and no extensive additional regulation.
>
> The Cost Review also recommended that BPA market a portion of the FBS equivalent to the planned output of CGS priced in a manner that ensures recovery of the plant's operating costs in the actual sales of the plant's output. Subject to further input, BPA's tentative conclusion is that the problems connected with this piece of the recommendation are not practicably solvable. It would involve selling a portion of the Federal Base System at a higher price equal to CGS's operating costs – a legal difficulty – and reduction of the lowest cost subscription inventory when it appears that we will be oversubscribed. CGS's operating costs are now so close to the market and to BPA's likely subscription power rates that the cost impact of this separation on both the subscription rate and the theoretical CGS rate would be negligible. Equity concerns among parties with subscription rights over who is left with the higher-priced portion of power would likely exacerbate the oversubscription issues (see power markets, revenues and subscription fact sheet). Finally, a robust market test should achieve the bulk of the cost review goal, without creating the substantial problems connected with putting a higher price on this portion of the subscription inventory.[15]

Despite these agreements for an ongoing market test, the chaos wrought by the Enron fiasco appears to have superseded all other plans and considerations, and made their continuation seem unnecessary.

In 2002, CGS's operator, Energy Northwest, wrote:

[15] Bonneville Power Administration. *Issues '98 Fact Sheet #1: Cost Management*. Portland: Bpa.gov, June 1998. PDF.

> Market test
>
> In 1998, a regional cost review made several suggestions for the operation of Columbia Generating Station. Most significantly, the review suggested that the Northwest's only nuclear power station prove itself on a market basis. As BPA and Energy Northwest eventually constructed the test, the plant's power would be given a value based upon daily, weighted-average prices at West Coast trading centers. A reasonable amount would be deducted for transmission losses and the cost of transmission.
>
> In every fiscal year since the challenge was made, Columbia Generating Station has proved itself a viable market asset. Since 1999, the total difference between the cost of operating Columbia and the replacement value of its generation is over $1.526 billion. During the volatile electrical market in 2001 the power worth exceeded cost by a factor of eight due to high market prices and reliability of the station.

Columbia Generating Station

Fiscal Year	Production Cost*	Power Worth
1999	$158,000,000	$174,000,000
2000	$175,600,000	$265,650,000
2001	$199,500,000	$1,597,246,000
2002	$196,000,000	$218,098.000
Total	$729,100,000	$2,255,661,000

> *Does not include interest and decommissioning costs.
>
> Interest cost ranged from $132 million to $110 million during the four-year period. Decommission contributions for the same time period range from $5 million to $6 million.[16]

This, apparently, was the final mention of the CGS "Market Test." Bonneville never held a proceeding to implement the Market Test, nor, as far as we have been able to determine, ever mentioned the issue again. Document requests to BPA and Energy Northwest concerning the Market Test have received the response that they were unable to find any relevant materials – in spite of the fact that our review has successfully found materials at BPA, Energy Northwest, and the Regional Planning Council.[17,18]

[16] Energy Northwest. *Draft Executive Board Report on Nuclear Programs.* 20 Sept. 2002. PDF. Appendix A.
[17] Glica, Alex. *Public Records Request 2013-51.* Message to Rose Anderson. 13 Nov. 2013. E-mail.
[18] Munro, Christina. *FOIA #BPA-2013-01739-F.* Letter to Charles Johnson. 5 Nov. 2013.

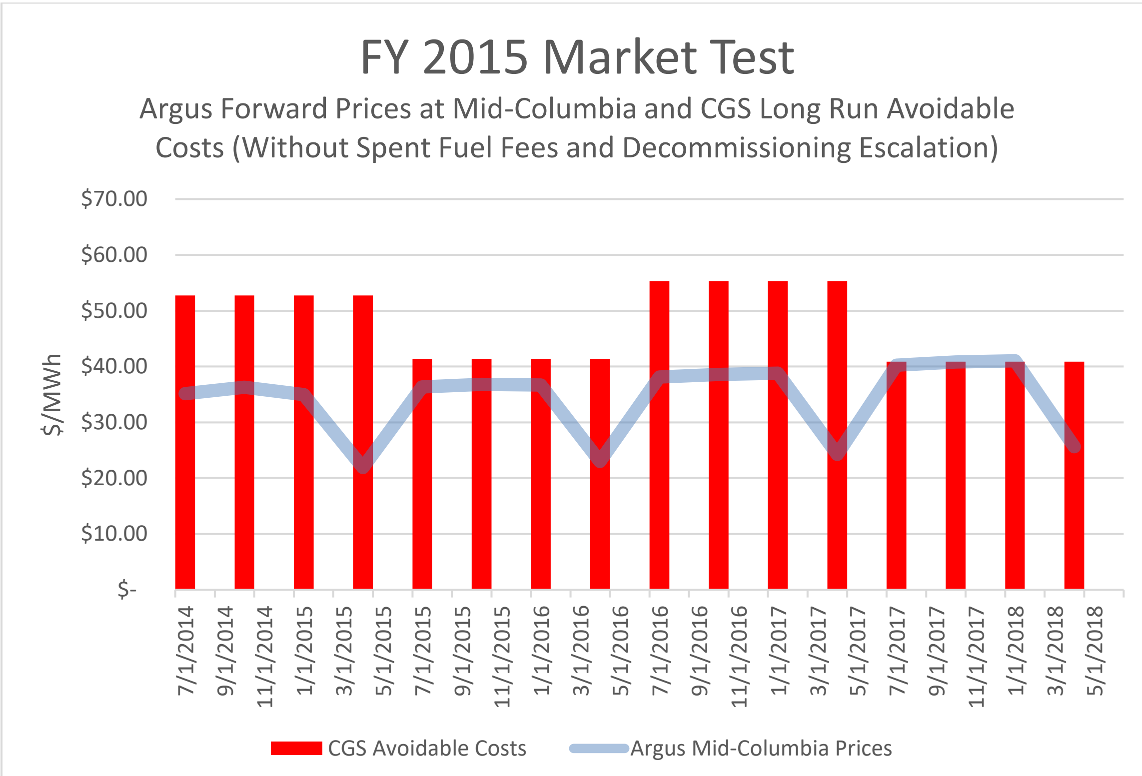

Figure 12: FY 2015 Market Test

In 2013, McCullough Research conducted a market test for CGS, using utility forecasting software and conducting over 30,000 stochastic runs.[19] In the chart above, McCullough Research has updated these figures each year based upon actual performance of the CGS and the market.[20]

CGS has failed the Market Test since 2009 and is likely to continue to do so for the foreseeable future.[21] Today, CGS fails the Market Test by a significantly larger margin than it has in the past.

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[19] Economic Analysis of the Columbia Generating Station, McCullough Research, December 2013, https://www.mresearch.com/pdfs/541.pdf, available in book form from Amazon

[20] Market Cost of the Columbia Generating Station During the FY 2014/2015 Refueling Cycle, McCullough Research, November 2015, https://www.mresearch.com/pdfs/20151116-CGS_costs_exceed_value.pdf and, Columbia Generating Station (CGS) Market Update, McCullough Research, June 2016, https://www.mresearch.com/pdfs/20160621-CGS_Market_Analysis.pdf

[21] Economic Analysis of the Columbia Generating Station, McCullough Research, December 2013, https://www.mresearch.com/pdfs/541.pdf, available in book form from Amazon

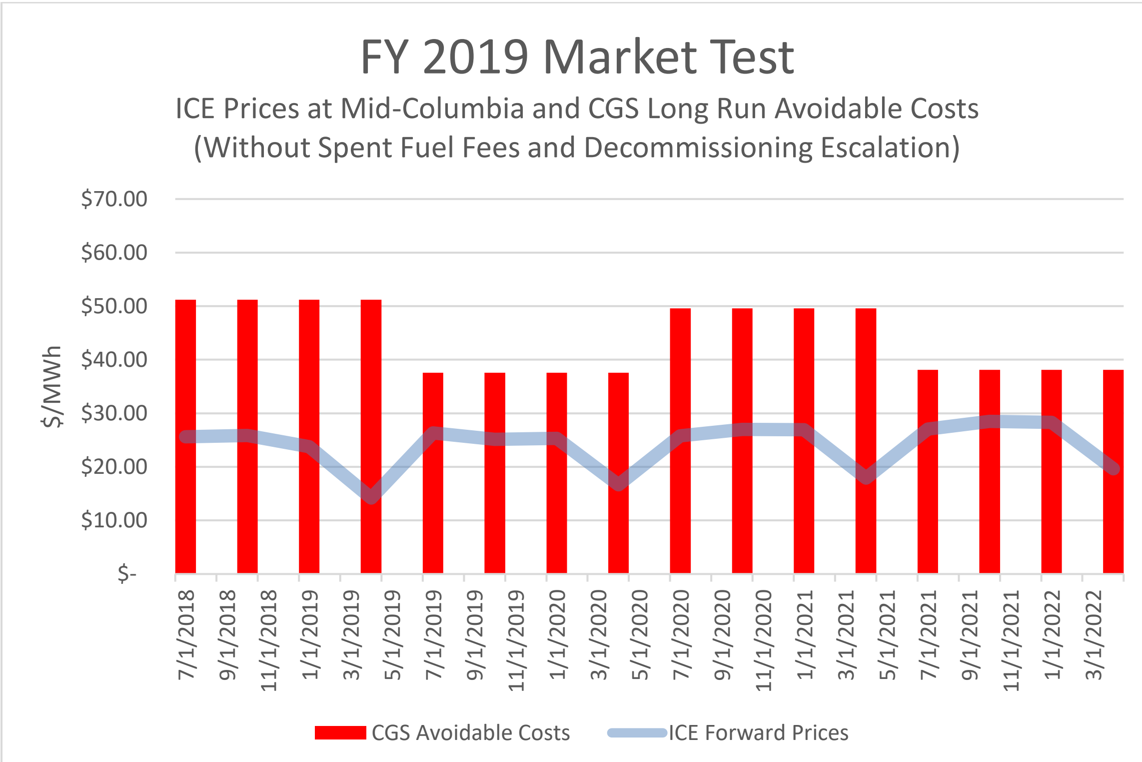

Figure 13: FY 2019 Market Test

In the last six years, renewables have become increasingly cost-competitive. These gains are expected to continue, allowing renewables to become economically sound on an un-subsidized basis.[22] Since FY 2012, the operating costs for CGS have ranged from $36.50/MWh to $50.50/MWh even when not including debt-financed O&M costs.[23] They are moving in the wrong direction (see Figure 10).

Conclusion

The proposed strategic plan fails to address the critical issues confronting BPA today. Technological change is an unrelenting feature of our society and refusing to acknowledge the challenges and benefits dooms those who do to failure.

[22] Lazard. "Levelized Cost of Energy Analysis – Version 10.0." December 15, 2016. Accessed December 20, 2016. <https://www.lazard.com/media/438038/levelized-cost-of-energy-v100.pdf>. See page 10.
[23] Energy Northwest. "2016 Annual Report." Accessed December 23, 2016. <https://www.energy-northwest.com/whoweare/finance/Documents/2016%20Energy%20Northwest%20Annual%20Report.pdf>. See page 24.

We recommend that Bonneville Power Administration consider the following to address its issues of competitiveness, operational inefficiency, reductions in borrowing authority, and cost control:

1) Submit the Columbia Generating Station (CGS) nuclear power plant to a market test and, if it fails, close the CGS as rapidly as possible thereafter;

2) Re-engineer the Coordination Agreement and the Canadian Treaty to make it easier for the Columbia River's hydroelectric dams to meet the growing need to back up the variable resources of wind and solar energy; and,

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