US Army Corps
of Engineers
Portland District

Willamette Basin Review Feasibility Study

APPENDIX J

Hydropower Impacts Analysis

June 2018

WILLAMETTE BASIN REVIEW

PEAK AGENCY RECOMMENDED PLAN

HYDROPOWER IMPACTS

Introduction

To the extent power production in the Willamette Valley is already de-optimized in response to Willamette Project Biological Opinion 2008 as part of the federal power system, any change in operations may entail further reduction in optimal power production. If a measure reduces the social value of hydropower production, an estimate will be made of the losses in monetary terms. Bonneville Power Administration (BPA) staff will be responsible for making an estimate of these losses. The monetary loss estimate will use the same underlying parameters and assumptions (discount rate, planning horizon, constant price levels) as the rest of the analysis.

In this study hydropower impacts are jointly estimated by Portland District and Bonneville Power Administration. Portland District staff performed the Willamette Basin projects operations simulations for a Base Year 2020 analysis and the Peak Agency Recommended Plan (Peak ARP) alternative for the Willamette Basin Review (WBR) study. Results of these simulations were formatted for BPA staff to simulate the hydropower generation.

In this study flood control operations and Spring refill operations are not modified. Water supply (both M&I & Irrigation) impacts occur during the conservation use season (April-October). No releases during the flood season (January-March) are different than current operations. Releases for water supply contracts do not start until April. Once a reservoir reaches the minimum conservation pool elevation, only inflow is passed in both the Base Case and the modeled alternative operations - no supplemental flow is provided for contracts once we reach minimum conservation pool elevation. Reservoirs may reach their minimum conservation pool level a little earlier than the Base Case in drier years before November. There are no additional reductions in reservoir elevations during the flood control season.

Analyses and results are shown for conservation use season (April-October).

The following sections include descriptions for procedures for estimating system hydropower under each system reservoir storage allocation, procedures for developing the monetized value of system hydropower for generation, and a conclusion with summary statements describing the hydropower impacts for each simulation.

Models used in the Analysis

Portland District used the HEC-ResSim computer model to simulate the reservoir operations in the Willamette Basin. ResSim is a sequential stream-flow routing computer model (discussed elsewhere in this report) used in the WBR study to simulate Willamette project reservoir regulation rules. The Baseline simulation represents what would have happened in the basin with the current operational conditions for an 80 year Period of Record (POR), while the alternative scenario analyzed what would have happened for a management strategy with specified allocations for Fish & Wildlife (F&W), Municipal & Industrial (M&I) diversions, and Agricultural Irrigation (AI) diversions. These simulations are run on a daily time step for the period of record. Results are post-processed (summarized) for impact evaluation. Parameters from the ResSim results that are needed for evaluating hydropower impacts are then transmitted to BPA staff for their evaluation.

BPA uses the HYDSIM model to simulate power production. HYDSIM is a deterministic hydro regulation model that simulates the month to month operation of the Pacific Northwest (PNW) Hydropower System in accordance with operating criteria and constraints based predominately on the Columbia River Treaty for Canadian projects and NMFS Biological Opinion and FERC requirements. HYDSIM is used to determine the hydro system generation and resulting project outflows, ending storage contents, etc., under varying inputs of inflows, power loads, operating procedures and constraints, and physical plant data. HYDSIM uses 14 periods in a year with April and August split into two periods, since these months have significant natural flow differences between their first and second halves on the Columbia River. For the WBR study, HYDSIM is run using the ResSim simulation outputs for reservoir elevations and reservoir inflows and outflows to obtain the power production history in the basin for the POR analyzed. The HYDSIM model was run in a continuous mode with project storage contents at the end of each of the 14 periods every year matching those of ResSim.

The HYDSIM analysis of a simulation produces the amount of power generated by each power project for each of the fourteen periods for every year of the POR analyzed, in this case fourteen period for about 80 years. Using Detroit Dam as an example, there will 80 values of power generated for the month of May (since there are 80 years in the POR), 80 values of power generated for the month of June, and so on, with the April and August periods divided into two parts each. Then the average of those 80 values for Detroit power in May is computed, the average of the 80 values of June computed, and so on. The end result is an average generation (in MW) for each power project for each month.

The WBR study is a conservation season study, and the conservation release season period is April through the end of October. As described in Appendix E, releases from November through March are not different than current operations. Release of stored water to satisfy consumptive uses do not begin until April of each year. Once a reservoir reaches the minimum conservation pool elevation, only inflow is passed in both the baseline and the modeled operations. There are not additional reductions in reservoir elevations during the flood season. Only the power generation and pricing for this window of time will be presented in this report, since the WBR study does not affect any operations during the winter season or the refill season.

BPA's AURORA is an electric energy market model owned and licensed by EPIS Inc., to forecast market clearing prices for electric power. The hourly market-clearing price is based upon a fixed set of resources dispatched in least-cost order to meet demand while subject to emissions limits. The hourly price is set equal to the variable cost of the marginal resource needed to meet the last unit of demand. A long-term resource optimization feature within the AURORA model allows generating resources to be added or retired based on economic profitability. Market-clearing price and the resource portfolio are interdependent. Market-clearing price affects the revenues any particular resource can earn and consequently will affect which resources are added or retired. AURORA sets the market-clearing price using assumptions of demand levels (load) and supply costs. The demand forecast implicitly includes the effect of price elasticity over time. The supply side is defined by the cost and operating characteristics of individual electric generating plants, including resource capacity, heat rate, and fuel price. AURORA recognizes the effect that transmission capacity and prices have on the system's ability to move generation output between areas. Input data to AURORA includes the following: an electricity demand model, coal market model, natural gas market model, new/future generating capacity database, as well as sulfur dioxide (SO2) and nitrous oxide (NOx) emissions allowance model.

Hydropower Energy Values

The expected value of hydropower production for the Willamette projects during April through October over a 50-year planning horizon is calculated for the Baseline and Agency Recommended Plan (ARP). The difference between the value for the Peak ARP and the value of energy of the Peak-No Action Plan condition gives an estimate of the hydropower impact of the ARP in dollar terms. This section explains how that value is estimated.

Energy Value

The value of energy production for any alternative is the product of the power produced and the market price forecast for that power.

Development of the power production market price estimates for the 50-year period of analysis follows these steps;

- **Step 1**: Obtain the forward energy market price forecast for the Mid-Columbia region based on the BPA's AURORA model study MidC_ReferenceCase_7-26-2017 which provides a monthly 20-year energy price forecast (Figure 1).

- **Step 2**: Develop seasonal shaping factor for "monthly" flat energy price variation and HLH energy price factors (Figure 3).

- **Step 3**: For comparison, obtain the U.S. Energy Information Administration (EIA) annual electric energy price outlook AEO 2017 for 'Electric Power Projections for EMM Region-Western Electricity Coordinating Council / Northwest Power Pool Area' (Figure 1).

- **Step 4**: Create the 50-year flat energy price forecast using BPA's 20-year forecast (Figure 4).

- **Step 5**: Amortize the flat energy price for the 50-year period of analysis.

- **Step 6**: Apply the seasonal "shaping" factors and HLH price factors to BPA's annual average energy price forecast (Figure 3) to obtain the monthly all-hours (flat) price and HLH energy price.

Finally, the BPA HYDSIM model is used to determine monthly average changes in hydropower generation. There are three peaking power projects in the Willamette Valley: Detroit, Green Peter, and Lookout Point. These projects have units that are designed to be run fully loaded to meet peak loads depending on the available water supply to run the units, but they generally do not generate continuously. These peak load periods are a subset of the heavy load hours (HLH) are 6 days per week at 16 hours per day. These projects all have re-regulation projects downstream so that outflows of these projects can be reregulated to a more normative flow. These projects are designated as Power Projects because of these features. The base power projects in the Willamette Valley generate more or less continually or all-hours (flat, 168 hours/week) and generate power in both peak load and non-peak load periods or in market terms both during heavy load hours (HLH, 96 hours/week and light load hours (LLH, 72 hours/week). Heavy and light load hours were estimated by actual historical generation from the past five years.

$$Flat\ Price = \frac{72 * LLH\ price + 96 * HLH\ price}{168}$$

Energy prices are determined by a forward market price forecast for the Mid-C market. The Mid-C market located in the mid-Columbia is the largest and most liquid market hub for electricity in the Pacific Northwest. As part of the rate setting process, market price forecasts for the Mid-C market are prepared using the BPA's Aurora pricing model.

Price forecasts using the AURORA model are used to estimate the cost of purchasing power on the secondary market.

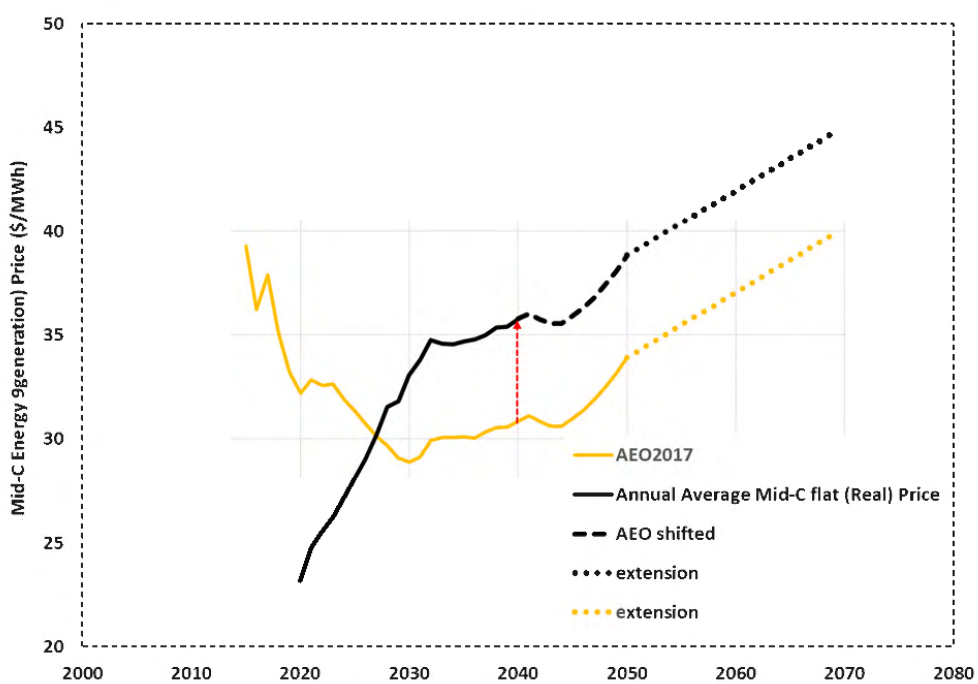
Simulations result recorded in MidC_ReferenceCase_7-26-2017 of the secondary power market were made using the BPA's AURORA model to produce a 20-year forecast of energy prices (converted to real 2018 dollars) for Heavy Load Hours (HLH) and Low Load Hours (LLH). The median of 3,200 pricing scenarios for HLH and LLH was used as the basis for developing long-term energy prices in this study.

Energy prices are highest when seasonal temperatures are lowest increasing the electrical power demand for indoor heating and when simultaneously river flow (hydropower generation) is lowest at the end of the regional annual dry period. Energy prices are lowest as seasonal temperatures begin to warm and there is reduced demand for heating simultaneously when snow melt runoff is highest and there is an excess of hydropower.

The U.S. Energy Information Administration (EIA) develops regional 30-year annual electric energy price outlook which provides the basis for extending the NPPC forecast. The AEO 2017 for 'Electric Power Projections for EMM Region-Western Electricity Coordinating Council / Northwest Power Pool Area' prices for generation.

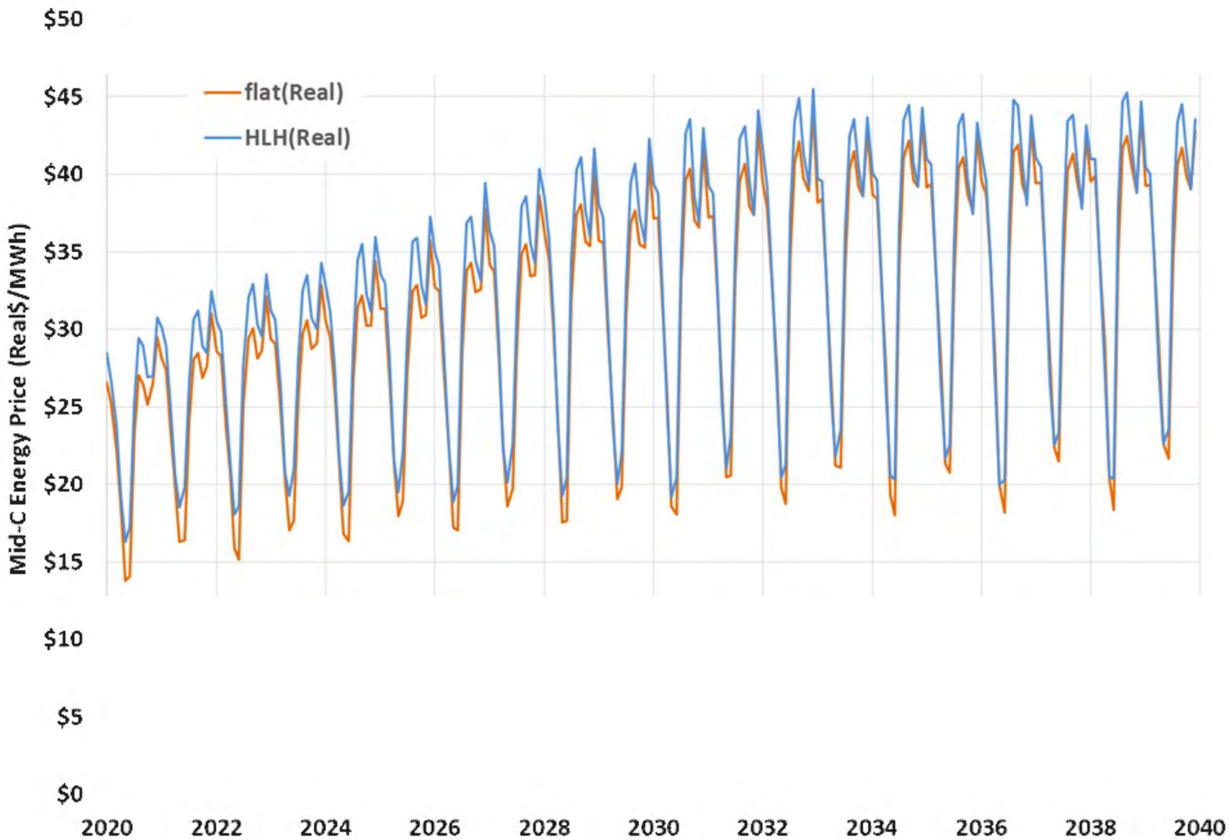
For comparison the BPA monthly prices are displayed as annual average prices along with the EIA regional outlook (both projections are in 2018 price level) in Figure 1.

Figure 1. Comparison of BPA flat average annual energy price and EIA Energy Price Projections



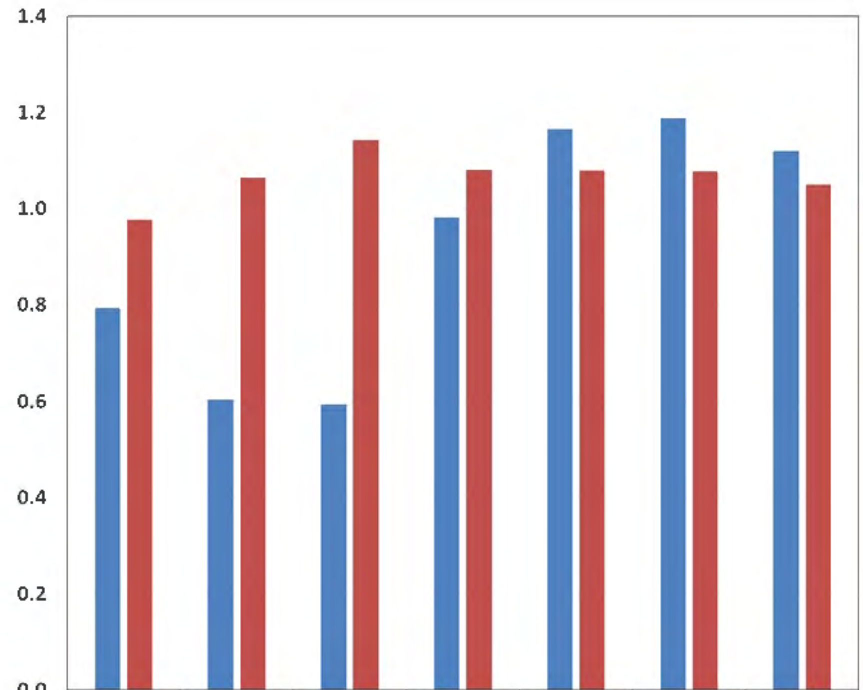
A long-term electrical energy price forecast was created by repeating the annual cycle of the monthly price shown in Figure 2. The forecast determined in this way is used as the basis for determining the value of the hydropower over the long-term for the projects with normative flows at flat prices and the 3 power projects at HLH prices.

Figure 2. Monthly All-hours (flat) and Heavy Load Hour (HLH) Price forecast (2018 Dollars)



The monthly price variation in the projection of the all-hours (flat) and HLH energy price (Figure 2) was characterized by determining the ratio of monthly to annual average price then the averaged over the forecast period to form “shaping” factors as shown in Figure 3. HLH price factors were determined similarly.

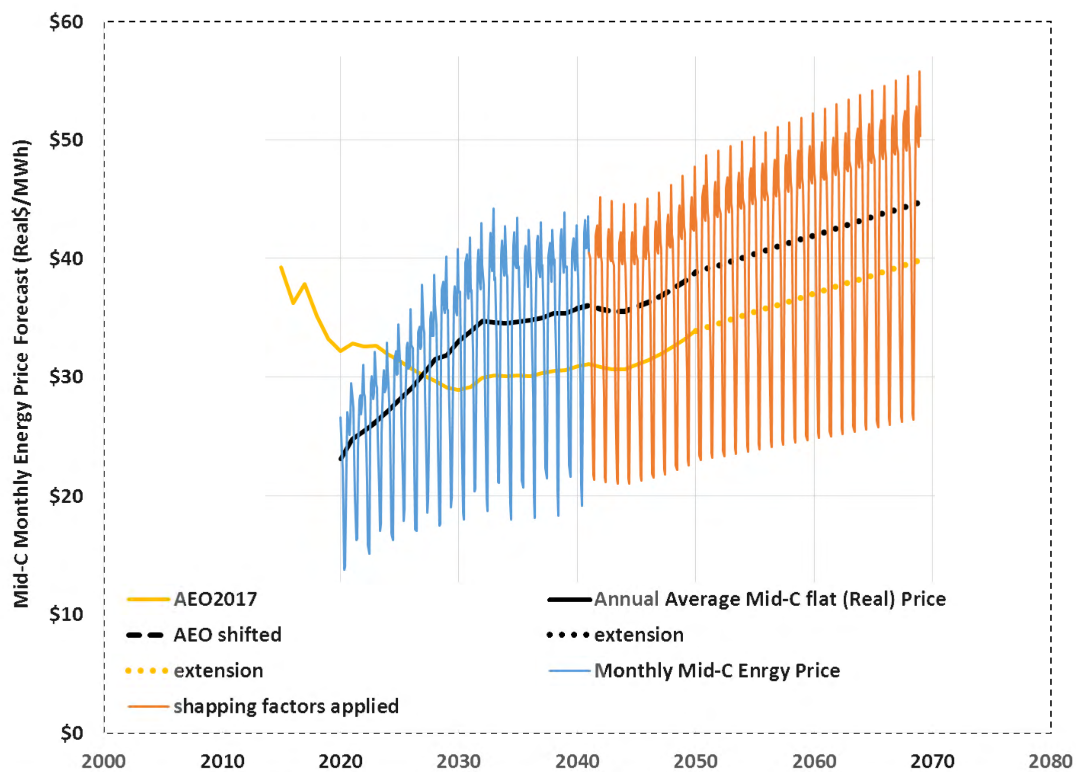
Figure 3. Monthly flat and HLH Price “shaping” factors



	Apr	May	Jun	Jul	Aug	Sep	Oct
flat (Real) Shaping Factor	0.792596	0.603529	0.593278	0.981470	1.164886	1.187899	1.118754
HLH Shaping Factor	0.977287	1.064165	1.142175	1.080445	1.079420	1.076909	1.049777

These shaping factors in Figure 3 were applied to the Mid-C Annual Average Energy Price Forecast in Figure 1 to obtain a long-term Mid-C Monthly Average Energy Price Forecast shown in Figure 4.

Figure 4. Mid-C Monthly Average Energy Price Forecast



An annual energy price was needed for the 50-year period of analysis for this study. A discount rate of 2.75% is used to first get the present value of the price forecast then amortized for the 50-year period. This process yielded an annual flat (all hours) energy price of $34.37/MWh.

The monthly all-hours energy price is computed by multiplying the annual energy price by the monthly "shaping" factors.

Table 1. Long-Term Energy Prices (Real 2018 dollars)

month	Flat (all-hours) Annual Price (Real)	HLH (peak) Annual Price (Real)
Apr	$27.24	$26.62
May	$20.74	$22.07
Jun	$20.39	$23.29
Jul	$33.73	$36.44
Aug	$40.03	$43.21
Sep	$40.83	$43.97
Oct	$38.45	$40.36

The annual Real Energy Prices, shown in Table 1 above, were applied to the modeled monthly average generation (aMW) to obtain the average value of generation for the Willamette Valley Projects for April through October.

The expected power value generated in the Willamette Basin April through October for the Base Year 2020 is estimated at $26.01 million. Table 2, below, presents the calculation of the hydropower benefit at the 2018 price level.

Table 2. Estimated Hydropower Values for the Conservation Season for the Base Year 2020.

		April	May	June	July	August	September	October	Conservation Season Total
1	**Generation**	**(aMW)**	**(aMW)**	**(aMW)**	**(aMW)**	**(aMW)**	**(aMW)**	**(aMW)**	**(aMW)**
2	Detroit*	43.8	61.5	21.4	16.1	16.4	36.6	44.8	34.4
3	Big Cliff	10.3	12.8	10.9	7.4	6.0	9.8	11.8	9.9
4	Cougar	15.4	19.3	17.5	14.3	16.5	12.3	16.3	16.0
5	Green Peter*	26.9	31.4	23.2	14.0	15.0	26.7	20.0	22.4
6	Foster	14.5	14.0	12.0	7.1	7.0	11.6	11.4	11.1
7	Hills Creek	19.2	24.5	20.6	14.0	16.7	16.4	18.7	18.6
8	Lookout Point*	34.7	52.1	46.2	27.6	30.2	37.3	41.3	38.5
9	Dexter	8.2	11.0	10.0	6.4	7.2	9.3	10.7	9.0
10	**Total Generation (aMW)**	**173.0**	**226.6**	**161.8**	**106.9**	**115.0**	**160.0**	**175.0**	**159.7**
11	Hours in Month **(hours)**	720	744	720	744	744	720	744	5136
12	Power Project **(aMW)**	105.4	145.0	90.8	57.7	61.6	100.6	106.1	95.3
13	Power Project **($ MIL)**	$2.02	$2.38	$1.52	$1.56	$1.98	$3.18	$3.19	$15.84
14	Flat **(aMW)**	67.6	81.6	71	49.2	53.4	59.4	68.9	64.4
15	Flat **($ MIL)**	$1.33	$1.26	$1.04	$1.23	$1.59	$1.75	$1.97	$10.17
Total Willamette Hydropower Value for Conservation Season Only ($ Mil)								**$26.01**	

The computation procedure in Table 2 results in total power production for April through October at each project under Base Year 2020 operating regimes. The power plants at the peaking projects (Detroit, Green Peter, Lookout Point) are termed "power projects" (designated by *) and are used primarily to generate power during Heavy Load Hours (peaking hours). The value of generation at the power projects is determined by multiplying the generation by the HLH annual price (in Table1). Projects downstream of the "peaking" power projects (Big Cliff, Foster, Dexter) perform a re-regulation function by generating power steadily each day through both the heavy load hours and the low load hours. Projects that generate power steadily are termed "flat" projects (Hills Creek and Cougar). The weekly combination of HLH prices and LLH prices is termed the flat price. The value of generation at the flat projects is determined by multiplying the generation by the flat "levelized" price (in Table 1).

In Table 2, rows 2-9 display each projects' simulated generation for each period April through October (labeled in row 1). The generation in each month is displayed in terms of period average megawatts (period generation expressed in megawatt-hours divided by the number of hours in the month). The average generation for each project in the last column on the right is the weighted average of the period generation in the April through October columns (weighting factor is the hours in each period shown in row 11). Row 10 in Table 2 is total generation for the period which is the simple sum of rows 2-9 where rows 12 and 14 are subtotals for the power projects* and the flat projects. The average April through October value for generation is then determined by multiplying the subtotal generation in rows 12 and 14 by the period hours and the appropriate (HLH or flat) price from Table 1. The sum of these average generation values is shown in the bottom row.

Table 3. Estimated Hydropower Values Under the Peak-No Action Plan.

	April	May	June	July	August	September	October	Conservation Season Total
Generation	**(aMW)**	**(aMW)**	**(aMW)**	**(aMW)**	**(aMW)**	**(aMW)**	**(aMW)**	**(aMW)**
Detroit*	43.7	61.5	21.8	17.6	18.3	35.6	39.1	33.9
Big Cliff	10.3	12.8	11.2	8.0	6.9	9.4	11.1	10.0
Cougar	15.4	19.4	17.7	14.6	17.4	12.0	16.4	16.1
Green Peter*	26.9	31.4	23.4	14.9	15.8	26.4	19.1	22.5
Foster	14.5	14.1	12.0	7.2	7.0	12.2	11.2	11.1
Hills Creek	19.1	24.5	20.9	14.7	17.5	16.2	17.5	18.6
Lookout Point*	34.6	52.4	46.6	29.4	32.1	35.9	39.2	38.6
Dexter	8.2	11.0	10.1	6.9	7.8	9.1	10.2	9.0
Total Generation (aMW)	**172.7**	**227.1**	**163.7**	**113.3**	**122.8**	**156.8**	**163.8**	**160.0**
Hours in Month **(hours)**	720	744	720	744	744	720	744	5136
Power Project **(aMW)**	105.2	145.3	91.8	61.9	66.2	97.9	97.4	89.9
Power Project **($ MIL)**	$2.02	$2.39	$1.54	$1.68	$2.13	$3.10	$2.92	$15.77
Flat **(aMW)**	67.5	81.8	71.9	51.4	56.6	58.9	66.4	65.1
Flat **($ MIL)**	$1.32	$1.26	$1.06	$1.29	$1.69	$1.73	$1.90	$10.25
Total Willamette Hydropower Value for Conservation Season Only ($ Mil)							**$26.02**	

This Peak-No Action Plan then becomes the basis for computing the effect of Peak Agency Recommended Plan.

Table 4 is the summary results of hydropower impacts for the Peak Agency Recommended Plan which shows a slight increase in hydropower generation and value primarily due to expected increased irrigation and municipal & industrial water supply use, increasing early season withdrawals when power values are higher.

Table 4. Estimated Hydropower Values under the Peak Agency Recommended Plan.

	April	May	June	July	August	September	October	Conservation Season Total
Generation	**(aMW)**	**(aMW)**	**(aMW)**	**(aMW)**	**(aMW)**	**(aMW)**	**(aMW)**	**(aMW)**
Detroit*	43.8	61.6	22.0	17.8	18.8	35.9	37.7	33.9
Big Cliff	10.3	12.8	11.2	8.1	6.9	9.8	10.8	10.0
Cougar	15.4	19.4	17.8	13.8	16.8	12.4	16.6	16.0
Green Peter*	26.9	31.5	24.3	16.9	17.7	26.2	16.1	22.8
Foster	14.5	14.1	12.4	8.1	7.8	11.9	10.2	11.3
Hills Creek	19.1	24.6	20.9	14.1	17.1	16.5	17.6	18.6
Lookout Point*	34.6	52.3	46.8	29.4	32.2	35.0	38.7	38.4
Dexter	8.2	11.0	10.1	6.9	7.8	8.9	10.1	9.0
Total Generation aMW)	**172.8**	**227.3**	**165.5**	**115.1**	**125.1**	**156.6**	**157.8**	**160.0**
Hours in Month **(hours)**	720	744	720	744	744	720	744	5136
Power Project **(aMW)**	105.3	145.4	93.1	64.1	68.7	97.1	92.5	95.1
Power Project **($ MIL)**	$2.02	$2.39	$1.56	$1.74	$2.21	$3.07	$2.78	$15.76
Flat **(aMW)**	67.5	81.9	72.4	51	56.4	59.5	65.3	64.8
Flat **($ MIL)**	$1.32	$1.26	$1.06	$1.28	$1.68	$1.75	$1.87	$10.23
Total Willamette Hydropower Value for Conservation Season Only ($ Mil)								**$25.99**

Hydropower Impacts Summarized

Hydropower impacts are summarized in Table 5. The impacts of the Peak Agency Recommended Plan (Table 4) were then compared to the Peak-No Action Plan value (Table 3) in order to calculate the economic effect of the Peak Agency Recommended Plan. There is a small loss for the Peak-No Action Plan when compared to the Base Year because growth in irrigation demand causes water to be withdrawn earlier in the season when hydropower values are higher but generation is reduced late in the season because of the early season withdrawals. Additional municipal and industrial water supply withdrawals earlier in the season also add to this effect, decreasing the hydropower value slightly.

Table 5. Estimated Hydropower Losses under the Peak Agency Recommended Plan.

ALTERNATIVE	UNITS	April	May	June	July	August	September	October	Conservation Use Season Average
GENERATION									
Base Year 2020	**(GWh)**	**124.6**	**168.6**	**116.5**	**79.5**	**85.6**	**115.2**	**130.2**	**820.2**
Peak No-Action Plan	**(GWh)**	**124.3**	**169**	**117.9**	**84.3**	**91.4**	**112.9**	**121.9**	**821.7**
Peak ARP	**(GWh)**	**124.4**	**169.1**	**119.2**	**85.6**	**93.1**	**112.8**	**117.4**	**821.6**
change	(GWh)	0.1	0.1	1.3	1.3	1.7	-0.1	-4.5	-0.1
change	(%)	0.08%	0.06%	1.10%	1.54%	1.86%	-0.09%	-3.69%	-0.01%
HYDROPOWER BENEFITS									
Base Year 2020	**($1,000's)**	**$3,346**	**$3,640**	**$2,565**	**$2,799**	**$3,571**	**$4,931**	**$5,157**	**$26,009**
Peak No-Action Plan	**($1,000's)**	**$3,340**	**$3,648**	**$2,595**	**$2,968**	**$3,814**	**$4,831**	**$4,824**	**$26,020**
Peak ARP	**($1,000's)**	**$3,342**	**$3,651**	**$2,624**	**$3,018**	**$3,888**	**$4,823**	**$4,646**	**$25,992**
benefit	($1,000's)	$2	$3	$29	$50	$74	($8)	($178)	($28)
change	(%)	0.06%	0.08%	1.12%	1.68%	1.94%	-0.17%	-3.69%	-0.11%

The Conservation Use season (April through October) annual hydropower generation loss is $28,000 (0.11%) for Peak Agency Recommended Plan when compared to the Peak-No Action Plan at full utilization of the reservoir storage allocations for, agricultural irrigation, municipal and industrial water supply, as well as anticipated BiOP Minimum Target flows.

BPA’s AURORA Model – Mid-C Average Energy Price Forecast

Communications with BPA

From: Diffely,Robert J (BPA) - PGPL-5 [mailto:rjdiffely@bpa.gov]
Sent: Friday, May 18, 2018 3:28 PM
To: Davidson, Russell L CIV (US) <Russell.L.Davidson@usace.army.mil>
Subject: [Non-DoD Source] FW: Long term Mid-C forecast

Russ,

In terms of the forecast, this is what I could get out of the forecasters today. They left at noon. I am on my way out now.

Rob

\\HQ5F01.bud.bpa.gov\public\Aurora\sharedPrices\MidC_ReferenceCase_7_26_2017.xlsx
<file:///\\HQ5F01.bud.bpa.gov\public\Aurora\sharedPrices\MidC_ReferenceCase_7_26_2017.xlsx>
Link is to the 2017-2035, 3200 iterations HLH/LLH
Attached is the 2020-2040 version, avgs only. Formatting is 10-15, just let me know how you’d like it sliced (WY?)

Thanks and have a great weekend (I’m out for the day but can get something to you early Monday if you get back to me..)

-Eric

From: Diffely,Robert J (BPA) - PGPL-5
Sent: Friday, May 18, 2018 10:44 AM
To: Graessley,Eric W (BPA) - PBA-6
Subject: RE: Long term Mid-C forecast

If you could provide anything today that would be great

Thank you,

Rob

From: Graessley,Eric W (BPA) - PBA-6
Sent: Thursday, May 17, 2018 3:27 PM
To: Diffely,Robert J (BPA) - PGPL-5
Subject: RE: Long term Mid-C forecast

I do, you’ll have to remind me of the format you’d like though, sorry

Forecast is available for either 2020-2040 or 2017-2035 (2020-2040 version has hourly Mid-C available

From: Diffely,Robert J (BPA) - PGPL-5
Sent: Thursday, May 17, 2018 3:15 PM
To: Graessley,Eric W (BPA) - PBA-6
Subject: Long term Mid-C forecast

Eric,

Do you have an ‘on-the-shelf’ long term mid-C rate forecast?

AURORA Model Results

Mid-C Average Energy Prices Forecast 7-26-2017

year	month	HLH	LLH	year	month	HLH	LLH	year	month	HLH	LLH
2020	1	28.04	23.63	2023	1	32.35	27.85	2026	1	38.18	32.39
2020	2	26.23	22.92	2023	2	31.75	28.09	2026	2	37.16	33.08
2020	3	23.42	19.83	2023	3	27.29	23.85	2026	3	31.42	28.16
2020	4	18.86	17.19	2023	4	21.53	20.58	2026	4	24.40	24.32
2020	5	16.05	10.27	2023	5	19.96	14.64	2026	5	20.60	16.30
2020	6	16.97	9.67	2023	6	21.75	13.76	2026	6	21.73	14.42
2020	7	24.73	19.98	2023	7	28.97	22.95	2026	7	33.67	27.66
2020	8	28.99	23.49	2023	8	33.68	27.01	2026	8	40.19	32.34
2020	9	28.45	22.90	2023	9	34.72	27.62	2026	9	40.63	33.02
2020	10	26.52	22.45	2023	10	31.90	26.94	2026	10	37.56	32.39
2020	11	26.55	25.48	2023	11	31.09	28.91	2026	11	36.13	34.78
2020	12	30.27	27.41	2023	12	35.56	32.05	2026	12	43.03	38.72
2021	1	30.15	25.52	2024	1	34.55	28.94	2027	1	40.31	34.72
2021	2	28.98	25.31	2024	2	32.85	28.76	2027	2	39.22	34.96
2021	3	24.95	21.49	2024	3	29.16	25.34	2027	3	32.92	30.08
2021	4	20.64	19.09	2024	4	23.08	22.18	2027	4	24.80	25.39
2021	5	18.56	13.36	2024	5	19.65	15.12	2027	5	22.32	18.40
2021	6	19.89	11.84	2024	6	20.62	12.67	2027	6	25.09	17.52
2021	7	26.63	20.84	2024	7	30.37	24.69	2027	7	35.46	28.79
2021	8	30.67	24.64	2024	8	36.36	28.90	2027	8	42.09	34.13
2021	9	31.24	24.90	2024	9	37.39	29.32	2027	9	42.78	34.82
2021	10	28.96	24.15	2024	10	34.03	28.94	2027	10	39.42	34.05
2021	11	28.53	26.49	2024	11	32.85	30.58	2027	11	38.07	35.90
2021	12	32.52	29.10	2024	12	37.92	34.12	2027	12	44.78	40.35
2022	1	31.11	26.50	2025	1	35.98	30.39	2028	1	43.32	37.49
2022	2	30.40	26.78	2025	2	35.37	31.23	2028	2	40.40	36.92
2022	3	26.03	22.49	2025	3	30.16	26.67	2028	3	34.80	32.36
2022	4	22.03	20.33	2025	4	23.14	22.69	2028	4	26.68	28.05
2022	5	18.38	13.24	2025	5	20.93	16.93	2028	5	21.72	17.21
2022	6	18.95	10.73	2025	6	23.61	15.85	2028	6	23.09	15.74
2022	7	28.11	22.22	2025	7	31.57	25.94	2028	7	38.89	32.02
2022	8	32.65	26.38	2025	8	38.24	30.28	2028	8	45.48	37.91
2022	9	33.53	26.73	2025	9	38.46	30.99	2028	9	46.37	38.41
2022	10	30.84	25.72	2025	10	35.21	29.96	2028	10	42.50	37.28
2022	11	30.09	27.97	2025	11	33.86	32.23	2028	11	40.65	38.96
2022	12	34.18	30.76	2025	12	39.98	36.04	2028	12	47.05	43.12

year	month	HLH	LLH
2029	1	43.74	37.48
2029	2	42.76	38.51
2029	3	35.68	33.22
2029	4	27.36	29.12
2029	5	23.07	20.28
2029	6	25.36	19.30
2029	7	37.94	32.29
2029	8	45.34	38.20
2029	9	46.77	38.59
2029	10	42.87	38.02
2029	11	40.97	39.83
2029	12	48.62	44.61
2030	1	46.05	40.04
2030	2	45.34	41.15
2030	3	37.70	35.65
2030	4	29.33	31.97
2030	5	22.50	20.76
2030	6	23.96	17.35
2030	7	40.74	35.79
2030	8	49.84	41.69
2030	9	50.95	42.26
2030	10	45.13	40.84
2030	11	43.18	42.31
2030	12	50.30	46.86
2031	1	46.79	41.03
2031	2	46.17	42.16
2031	3	39.10	37.24
2031	4	29.99	32.96
2031	5	25.08	23.40
2031	6	27.60	20.44
2031	7	41.89	36.62
2031	8	50.40	42.70
2031	9	51.36	44.70
2031	10	47.09	42.66
2031	11	44.53	44.55
2031	12	52.59	49.33

year	month	HLH	LLH
2032	1	50.51	44.36
2032	2	47.53	43.53
2032	3	41.12	39.60
2032	4	32.13	35.42
2032	5	24.82	22.82
2032	6	25.76	18.64
2032	7	45.27	37.31
2032	8	52.66	45.05
2032	9	54.50	46.63
2032	10	50.20	45.48
2032	11	47.63	46.65
2032	12	55.18	51.56
2033	1	49.05	44.63
2033	2	48.81	45.67
2033	3	40.93	40.23
2033	4	32.01	35.58
2033	5	26.88	25.24
2033	6	29.10	22.06
2033	7	44.84	37.72
2033	8	52.47	46.33
2033	9	53.76	47.90
2033	10	50.05	46.31
2033	11	47.65	47.62
2033	12	53.93	51.26
2034	1	50.38	46.45
2034	2	49.83	46.27
2034	3	41.78	41.28
2034	4	32.77	37.23
2034	5	25.89	22.21
2034	6	25.49	18.92
2034	7	46.08	38.55
2034	8	54.69	47.74
2034	9	55.89	49.31
2034	10	51.27	47.81
2034	11	49.32	49.28
2034	12	55.72	53.24

year	month	HLH	LLH
2035	1	52.48	47.08
2035	2	52.02	48.24
2035	3	44.06	43.11
2035	4	33.90	38.74
2035	5	27.80	26.56
2035	6	28.86	23.49
2035	7	45.64	38.43
2035	8	55.33	46.92
2035	9	56.17	47.89
2035	10	50.97	47.79
2035	11	47.93	48.39
2035	12	55.48	52.83
2036	1	53.81	48.61
2036	2	51.67	48.78
2036	3	45.08	44.02
2036	4	35.11	39.62
2036	5	26.10	25.86
2036	6	26.49	20.00
2036	7	47.95	41.15
2036	8	58.45	48.17
2036	9	57.91	50.18
2036	10	53.03	48.96
2036	11	49.58	50.73
2036	12	57.11	54.91
2037	1	54.56	49.53
2037	2	53.75	50.62
2037	3	45.32	44.69
2037	4	35.28	40.34
2037	5	29.97	29.21
2037	6	30.96	25.33
2037	7	48.14	40.53
2037	8	57.68	47.76
2037	9	58.20	50.38
2037	10	53.83	50.37
2037	11	50.18	50.89
2037	12	57.27	55.01

year	month	HLH	LLH
2038	1	55.40	50.93
2038	2	55.44	51.97
2038	3	46.92	46.91
2038	4	37.02	42.62
2038	5	27.79	27.45
2038	6	27.52	21.17
2038	7	51.13	41.36
2038	8	60.47	50.92
2038	9	61.23	52.45
2038	10	56.77	52.46
2038	11	52.51	52.49
2038	12	60.48	57.93
2039	1	55.71	51.87
2039	2	55.12	52.99
2039	3	47.11	47.72
2039	4	37.58	42.80
2039	5	31.20	31.16
2039	6	32.47	26.36
2039	7	51.58	42.13
2039	8	59.76	51.03
2039	9	61.33	52.33
2039	10	57.13	52.02
2039	11	53.81	53.67
2039	12	59.96	57.67
2040	1	57.13	54.04
2040	2	54.47	52.93
2040	3	48.71	49.25
2040	4	38.88	45.35
2040	5	29.29	29.21
2040	6	28.71	24.64
2040	7	54.44	44.64
2040	8	64.54	52.10
2040	9	65.70	54.01
2040	10	59.08	55.11
2040	11	58.08	56.50
2040	12	62.25	59.62