RHWM Process Workshop

BP-16 Rate Period –
Explaining the Change in the Tier 1 System

Rates Hearing Room
August 26, 2014

RHWM Process Workshop Agenda

Topic	Presenter
Intro and Purpose of Workshop, Introductions	Peter Stiffler
Part 1	
Above RHWM Load Effects System Shape Effects Rate Impact of a RHWM Tier 1 System Capability change	Peter Stiffler Emily Traetow Lindsay Bleifuss
Part 2	
Tier 1 System Firm Critical Output (T1SFCO)	
• T1SFCO Changes – Monthly versus Annual Average	Tyler Llewellyn
• Spill Assumption Changes	Holly Harwood
• AOP Assumption Changes	Pam Kingsbury
• Thermal Availability	Tim Misley Rob Diffely
Part 3	
Process Schedule Revision	Peter Stiffler
Discussion: •Customer feedback on information provided	All/Scott Wilson
Next Steps	Peter Stiffler

Customer Comments Review

- Significant concern over a reduction in the Tier 1 System Firm Critical Output.
- These concerns are related to:
  - Effect of lower RHWMs on existence and amount of Above RHWM loads,
  - Rate Impact of lower Tier 1 Sales, and higher service of Above RHWM loads at Tier 2 or self-supply rates,
  - Effect of system shape changes on seasonal loads, like irrigation.
- Customers express a desire to understand the reasons behind the changes in the Regulated Hydro output from HYDSIM:
  - Spill assumption changes and the 2014 Biological Opinion implementation assumptions,
  - Assured Operating Plan/Detailed Operating Plan and Canadian Operation impacts.
- Interest in both annual average effects and monthly shape effects.
- Customers have procedural/process change requests for the RHWM Process:
  - Timing extended for improved dialogue,
  - Lack of transparency.

Above RHWM Loads

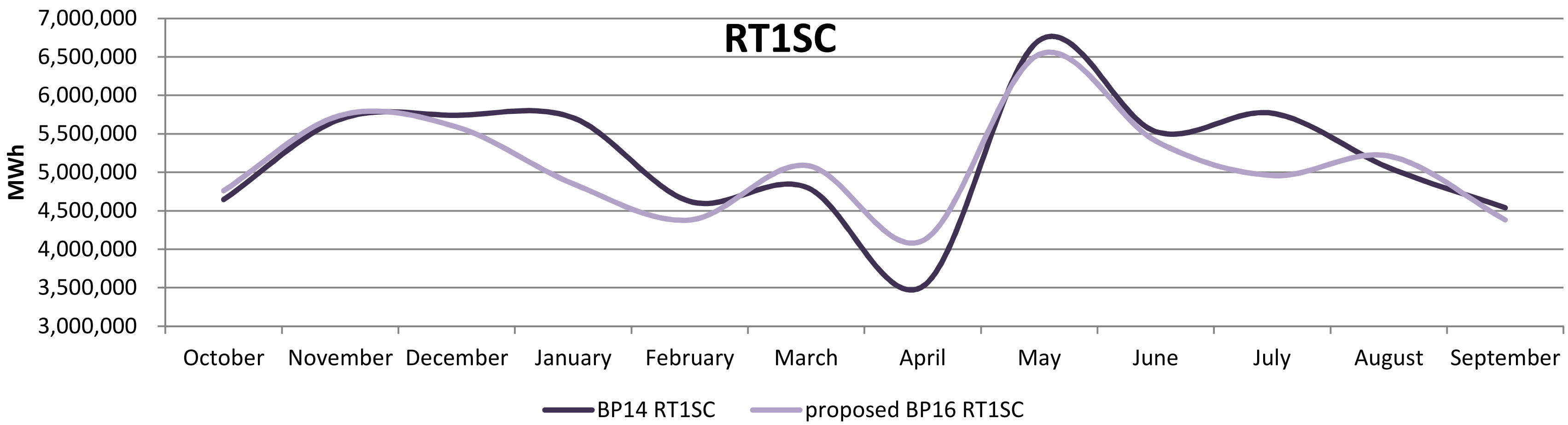
- BPA isolated the effect of a change in the Tier 1 System on Above HWM loads service by removing the effect of a change in customer loads:
  - Compute new Above RHMW loads assuming the BP-14 RHWM Tier 1 System Capability, and subtract these Above RHWM Loads from those computed in this RHWM Process for BP-16.
  - To normalize for varying customer size, divide the these Above RHWM load deltas by each customers Gross Net Requirement (TRL – NLSL – Existing Resources).
- Results:

Summary Across All Customers		
Average Above RHWM load across all customers	0.59%	of Gross Net Requirement Load*
Proportion of customers affected	30%	of all Preference Customers
Average Above RHWM load change among affected customers	1.97%	of Gross Net Requirement Load*
*Adjustment not made for self supplied Above RHWM Load.		

System Shape Changes

Customer Impact for Seasonal Loads

Q: The RHWM Tier 1 System Capability (RT1SC) is being reduced primarily in April, May and July, does this adversely impact customers with irrigation load?



- The BP-16 RT1SC (compared to the BP-14 RT1SC) is going up in April; the winter months are being reducedjust as much as the summer months. The graph on slide 14 of the Initial RHWM Presentation Materials displayed changes in the Regulated Hydro projects between the two RHWM Processes, not the entire RHWM Tier 1 System Capability.
  - http://www.bpa.gov/power/pl/regionaldialogue/implementation/documents/docs/CustomerFollowUp_RHWM_BP-16Workshop-August52014_rev_080814.pdf

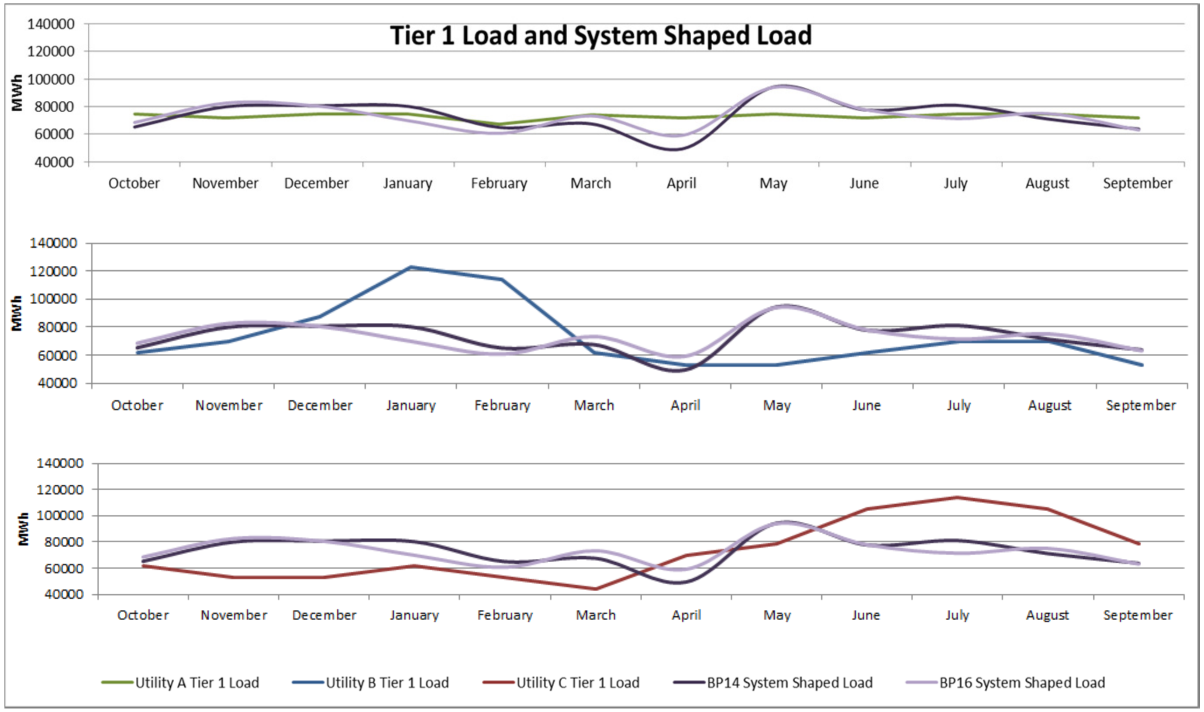
- The shape of the RT1SC by itself does not impact a customer's total annual Load Shaping Charges; although it does impact cash flow. Only in combination with Load Shaping Rates does the shape of the system impact a customer's annual charges paid to BPA. RT1SC shape change affects all customers in the same way regardless of their load shape (see next few slides for examples).

	October	November	December	January	February	March	April	May	June	July	August	September	TOTAL		*annual aMW*
BP14 RT1SC (MWh)	4,644,975	5,689,373	5,740,482	5,708,017	4,622,237	4,806,748	3,515,695	6,713,270	5,528,844	5,767,718	5,060,199	4,538,952	**62,336,510**		*7116*
BP16 RT1SC (MWh)	4,760,619	5,738,999	5,589,295	4,849,956	4,213,495	5,089,446	4,111,327	6,531,560	5,406,827	4,957,679	5,210,578	4,381,194	**60,840,976**		*6945*
BP16 less BP14 (MWh)	115,645	49,626	(151,188)	(858,060)	(408,742)	282,698	595,633	(181,711)	(122,016)	(810,039)	150,379	(157,758)	**(1,495,535)**		*(171)*
BP16 less BP14 (aMW)	*155*	*69*	*(203)*	*(1,153)*	*(608)*	*380*	*827*	*(244)*	*(169)*	*(1,089)*	*202*	*(219)*	***(171)***		

Load Shaping Charges Example 1: Flat Load Shaping Rates

	Utility A	Utility B	Utility C
Load Shape:	Flat	Winter-Peak	Summer-Peak
Net Requirement (annual aMW):	100	100	100
RHWM BP14 (annual aMW):	105	105	105
Non-Slice TOCA BP14:	1.40528%	1.40528%	1.40528%
RHWM BP16 (annual aMW):	103	103	103
Non-Slice TOCA BP16:	1.43982%	1.43982%	1.43982%

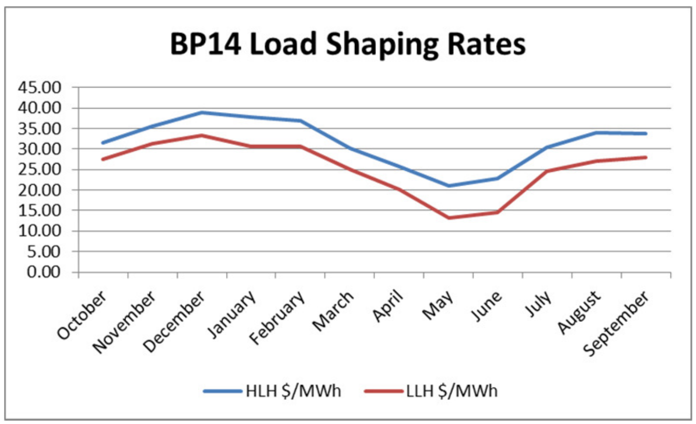
- The example has three utilities with the same total annual load but different load shapes. Since their annual load is all the same, they all have the same System Shaped Loads (SSL).
- The SSL is 100 annual aMW in BP-14 and BP-16, since the Non-Slice TOCA increases when the denominator (aka Sum of RHWM/RT1SC) decreases.
- If one keeps the Load Shaping Rates flat (the same rate each Monthly/Diurnal period), then each utility has:
- i) different monthly Load Shaping Charges and Credits; and ii) all of their annual Load Shaping Charges sum to $0.



	Load Shaping Rates $/MWh	Utility A Load Shaping Charges w/ BP14 System Shaped Load	Utility A w/ BP16 System Shaped Load	Utility B Load Shaping Charges w/ BP14 System Shaped Load	Utility B w/ BP16 System Shaped Load	Utility C Load Shaping Charges w/ BP14 System Shaped Load	Utility C w/ BP16 System Shaped Load
October	28.85	$ 263,264	$ 168,937	$ (114,094)	$ (208,421)	$ (114,094)	$ (208,421)
November	28.85	$ (226,513)	$ (303,825)	$ (284,790)	$ (362,102)	$ (790,242)	$ (867,554)
December	28.85	$ (180,879)	$ (175,285)	$ 199,941	$ 205,535	$ (810,963)	$ (805,369)
January	28.85	$ (167,716)	$ 131,827	$ 1,224,008	$ 1,523,551	$ (545,074)	$ (245,531)
February	28.85	$ 64,763	$ 188,486	$ 1,411,481	$ 1,535,204	$ (357,601)	$ (233,878)
March	28.85	$ 194,793	$ 29,461	$ (179,680)	$ (345,012)	$ (685,132)	$ (850,464)
April	28.85	$ 651,860	$ 369,405	$ 91,016	$ (191,439)	$ 596,468	$ 314,013
May	28.85	$ (575,268)	$ (566,690)	$ (1,205,352)	$ (1,196,774)	$ (447,174)	$ (438,596)
June	28.85	$ (164,316)	$ (168,730)	$ (472,434)	$ (476,848)	$ 791,196	$ 786,782
July	28.85	$ (191,920)	$ 87,081	$ (316,552)	$ (37,551)	$ 947,078	$ 1,226,079
August	28.85	$ 94,924	$ (17,970)	$ (29,708)	$ (142,602)	$ 981,196	$ 868,302
September	28.85	$ 237,008	$ 257,305	$ (323,836)	$ (303,539)	$ 434,342	$ 454,639
Total Charges/(Credits)		$0	$0	$0	$0	$0	$0
Total $/MWh		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Load Shaping Charges Example 2:
BP14 Load Shaping Rates (same utility loads from Example 1, previous slide)

	BP14 Load Shaping Rates		Utility A Load Shaping Charges (Flat)		Utility B Load Shaping Charges (Winter)		Utility C Load Shaping Charges (Summer)	
	HLH $/MWh	LLH $/MWh	w/ BP14 System Shaped Load	w/ BP16 System Shaped Load	w/ BP14 System Shaped Load	w/ BP16 System Shaped Load	w/ BP14 System Shaped Load	w/ BP16 System Shaped Load
October	31.59	27.43	$ 255,318	$ 158,675	$ (140,141)	$ (236,784)	$ (140,141)	$ (236,784)
November	35.56	31.27	$ (294,336)	$ (385,481)	$ (353,657)	$ (444,803)	$ (943,653)	$ (1,034,798)
December	38.84	33.27	$ (253,826)	$ (247,211)	$ 227,224	$ 233,840	$ (1,047,996)	$ (1,041,380)
January	37.80	30.67	$ (246,108)	$ 130,006	$ 1,427,121	$ 1,803,234	$ (698,721)	$ (322,608)
February	36.89	30.60	$ 52,958	$ 203,356	$ 1,641,484	$ 1,791,882	$ (451,183)	$ (300,785)
March	30.23	25.10	$ 170,181	$ 5,365	$ (192,635)	$ (357,451)	$ (682,784)	$ (847,600)
April	25.76	20.12	$ 520,843	$ 284,751	$ 61,309	$ (174,784)	$ 469,218	$ 233,126
May	21.00	13.08	$ (404,778)	$ (419,794)	$ (773,827)	$ (788,843)	$ (313,375)	$ (328,391)
June	22.73	14.57	$ (152,649)	$ (151,539)	$ (367,139)	$ (366,029)	$ 471,436	$ 472,546
July	30.49	24.50	$ (236,128)	$ 44,593	$ (355,769)	$ (75,048)	$ 864,445	$ 1,145,167
August	33.96	27.09	$ 58,474	$ (72,792)	$ (74,383)	$ (205,649)	$ 1,009,832	$ 878,566
September	33.65	27.90	$ 228,651	$ 255,528	$ (374,261)	$ (347,384)	$ 443,683	$ 470,560
Total Charges/(Credits)			**-$301,400**	**-$194,542**	**$725,325**	**$832,183**	**-$1,019,239**	**-$912,381**
Total $/MWh			-$0.34	-$0.22	$0.83	$0.95	-$1.16	-$1.04



- Since the BP-14 Load Shaping Rates are higher in the winter, Utility B with the Winter Load Shape has the highest Load Shaping Charges.
- Utility C has the lowest Load Shaping Charges since it is receiving larger credits in the winter in comparison to its charges in the summer.
- All three utilities saw their Load Shaping Charges increase by $0.12 per MWh.
- If one values the RT1SC using the Load Shaping Rates (multiply the Monthly/Diurnal RT1SC by the BP-14 Monthly/Diurnal Load Shaping Rates); then the BP-14 RT1SC is valued at $1,820,043,969 or $29.20/MWh and the BP-16 RT1SC is valued at $1,768,957,111 or $29.08/MWh. The same $0.12 $/MWH difference.

Explaining the Change in the T1SFCO

Annual Average Versus Monthly Changes

Identifying Drivers of Hydro Generation Changes

- Explaining changes in generation at the Lower Snake dams is more straightforward than the projects on the Columbia.
  - The Lower Snake projects have minimal changes in outflow during the spill season.
  - The monthly changes in generation can be explained and the effect of the changes in spill assumptions can be quantified.
- For the Columbia River dams it is difficult to isolate the monthly effect of individual changes due to the interactions between changes in project operations.
  - The changes in Canadian operations and changes in other upstream project operations (such as Libby & Albeni Falls) change the inflows into Grand Coulee.
  - These changes in inflows change the way the model reshapes flows from Grand Coulee, which can shift effects of upstream changes out in time and across multiple months.
  - Changes in monthly flows in the Columbia alter the affect of the change in spill assumption at John Day Dam.
- As explained earlier, only changes that affect the annual average estimate of system output affect the RHWM.
- For these reasons we have explained flow changes from Canadian and other upstream dams on an annual average basis.
- Changes in spill assumptions are explained at a more detailed level.
- Detailed information about how the flow changes affect generation at each project by month are also being provided for transparency.

Method to Separate Average Annual Drivers

- **Identifying Primary Drivers**
  - Reviewed differences in average annual generation for Federal projects. This identified projects with differences that required further review.
  - Reviewed average annual outflow for Federal projects to determine whether regulated flows caused any of the differences.
  - Reviewed changes in average annual outflow from storage projects upstream of Federal projects. This identified the upstream operations that contributed to the changes in outflow at Federal projects.
  - Reviewed spill assumption changes for Federal projects to determine whether they caused any of the differences.
- **Quantifying Primary Drivers**
  - Lower Snake: Because average annual outflow did not change for these projects, the change in spill assumptions was isolated as the driver of the generation differences. The change in spill at each project was multiplied by each project's HK (factor used to calculate generation based on flow through a turbine) to verify the change was due to spill.
  - John Day: Because both the spill assumption and outflow changed for this project, two calculations were required to separate the impacts.
    - Spill Assumption: Multiplied the spill percentage change by the outflow to estimate the difference in spill due to the change in spill assumption. This difference in spill was multiplied by John Day's HK to estimate the change in generation.
    - Outflow (primarily due to Canadian operations): Multiplied the change in outflow by John Day's incremental HK to estimate the change in generation.
  - Other Columbia Projects: Because spill assumptions did not change for these projects, the change in outflow (primarily due to Canadian operations) was isolated as the primary driver of the generation differences. Generation differences were reviewed to verify the changes were consistent with the change in outflow.

Explaining the Change in the T1SFCO

Spill Assumption Changes

Rate Impact of a Change in the Tier 1 System

- Context: roughly 170 aMW less generation under critical, and little change in generation under average water.

- The exact impact on the PF Tier 1 Rate is not yet modeled, but generally:
  - Less generation under 1937 water lowers individual customers' Rate Period High Water Marks, which lowers Tier 1 Sales. Since the PF Tier 1 Rate equals the net Revenue Requirement divided by Sales, this pushes the rate higher.
- Sales impact is mitigated by :
  - Increased secondary revenues because Tier 1 Sales are tied to 1937 critical generation (on an annual average basis), the widening of the difference between average water generation and 1937 critical water generation increases anticipated secondary energy sold on the trading floor.
  - Existence of Headroom (some customers having a net requirement that is smaller than its Rate Period High Water Mark). A portion of the 170 aMW decrease in 1937 critical generation will not lead to lower Tier 1 Sales.

- However, since Headroom decreases system augmentation requirements to serve DSI loads, additional augmentation expenses will increase the revenue requirement.

HYDSIM Spill Assumptions Consistent with 2014 Biological Opinion

- Operations in the 2014 Biological Opinion (BiOp) are generally the same as the 2008/2010 BiOp with a few exceptions.
- The BiOp includes an adaptive management framework that allows for adjustments in fish operations as conditions change and new, relevant information becomes available.
- BPA must make assumptions about how operations are likely to evolve given the latest scientific information.
- BPA has updated its assumptions regarding how the BiOp will be implemented to reflect our current understanding of the scientific information and status of BiOp implementation.

HYDSIM Spill Assumption - Changes from BP-14

The maximum transport/no spill operation during the spring in dry years at the Snake River collector projects (Lower Granite, Little Goose and Lower Monumental) is no longer assumed to occur.

- In prior rate cases, BPA assumed that the maximum transport operation would occur because the available data showed transported fish returned at higher rates than fish that migrated in-river.
- More recent data continues to show a benefit for transport, but that benefit has decreased due to improvements with in-river survival.
- The 2014 BiOp now calls for an annual review of the available information to determine what operation would be best for fish, and establishes a general goal of transporting about 50 percent of the fish.
- The maximum transport operation has not yet been implemented, and while a maximum transport operation is still possible, if it is determined to be best for fish, it is not assumed in the BP-16 rate case firm hydro forecasts.

HYDSIM Spill Assumption - Changes from BP-14 (cont.)

At John Day and Ice Harbor dams, BPA is no longer assuming that lower spill amounts will be implemented during this rate period.

- Instead, the analysis for the RHWMs for the fiscal year 2016-2017 rate period assumes that those projects will continue to have two alternating operations, as if they were doing a comparative test.
- BPA continues to believe that available testing information shows that the performance standards can be met with lower spill levels, but does not expect to complete the regional review process that will lead to a determination regarding which operations meet the performance standard before the rate period begins.
- Until that process is completed these projects will continue the two-treatment operation.

There is a reduction in Tier 1 energy associated with the assumption that summer spill will end sometime in August as the number of migrating fish declines significantly.

- BPA's assumption about the average date for spill cessation is later in August than it was in the previous rate case because we now have additional years to add to the average, and those years had later spill cessation trigger dates.

HYDSIM Spill Assumption - Changes from BP-14 (cont.)

April Spill Start Dates and Spring to Summer Transition Dates at Snake River Projects

- The 2014 BiOp eliminated the staggered start and now calls for spill operations at all Snake River dams to begin on April 3.
  - The last rate case study used the previous BiOp's spill start dates of April 5 at Little Goose and April 7 at Lower Monumental and Ice Harbor.
  - Current assumptions start all Snake River spill on April 3, consistent with the new BiOp.

- The 2014 BiOp also changed the biological trigger for transition to summer operations at these dams.
  - At the time the rate case study assumptions were developed it was unclear how this trigger would be determined.
  - The assumption made was it would be the same as recent years.

Explaining the Change in the T1SFCO

Changes in Canadian Operations

Assured Operating Plan (AOP) Background

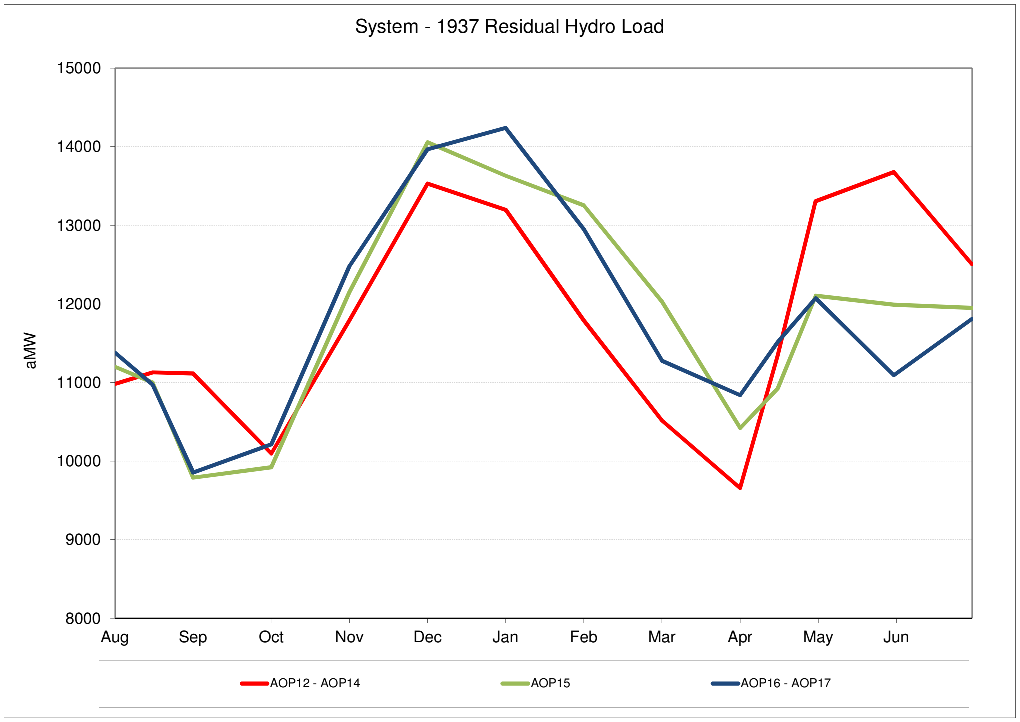
- The Treaty requires the entities to create an AOP for Canadian storage each year, six years in advance.
- The AOP must be an optimum power and flood control operation.
- Power studies typically include operating criteria based on critical rule curves. The critical period is 42.5 months long (16 August 1928 – 29 February 1932).
- AOPs do not include most modern non-power requirements.
- AOP studies use BPA White Book load and resource forecasts, and loads and resources are balanced over the critical period.
- Studies are run to a regional residual hydro load.

Detailed Operating Plan (DOP) Background

- Immediately prior to the operating year (August – July), the entities prepare a Detailed Operating Plan that guides the actual operation of Canadian Treaty projects.
- Changes from the AOP must be mutually-agreed upon by the U.S. and Canada. Any changes from the AOP are generally minor.

Recent History of Assured Operating Plan Residual Hydro Loads

- AOP15 and later AOPs show a decrease in May-July hydro load compared to earlier AOPs, due mainly to changes forecast loads and resources.
- AOP procedures for imports/export were changed beginning with the AOP15 to be more consistent with Treaty requirements.

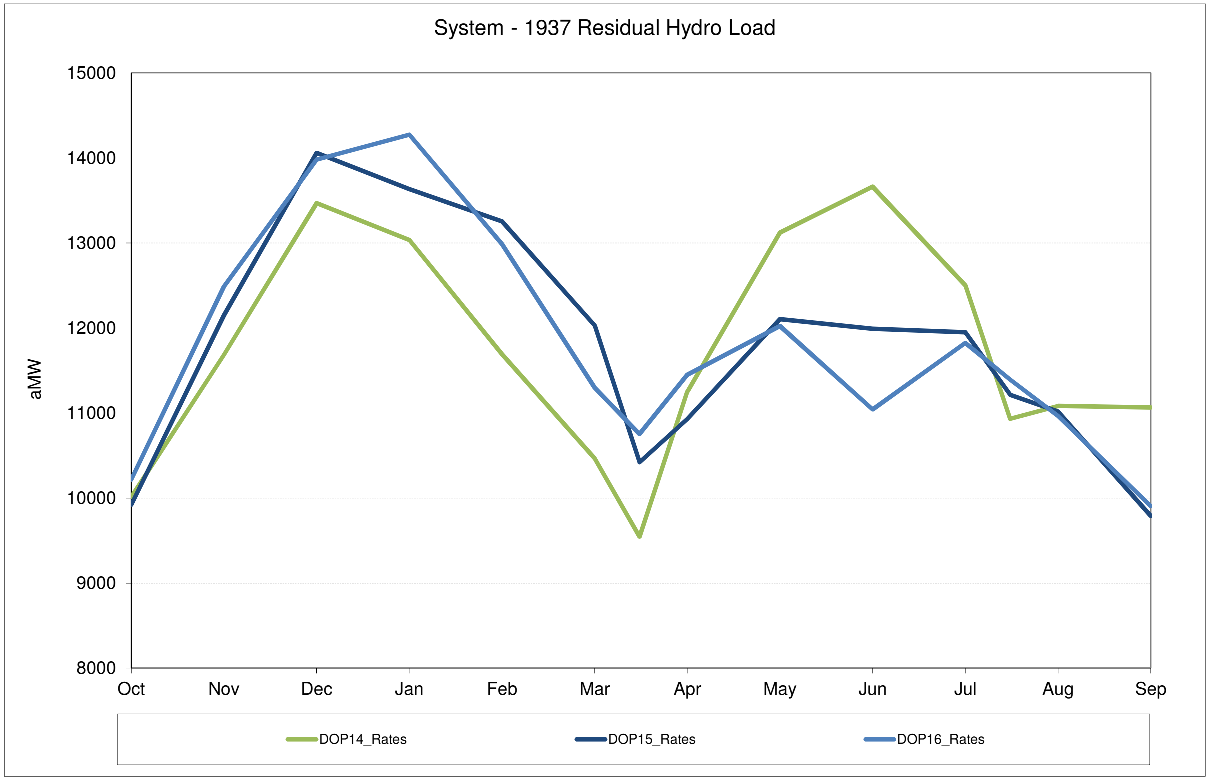


System - Residual Hydro Load (aMW)

	August I	August II	September	October	November	December	January	February	March	April I	April II	May	June	July	Annual
AOP12	10,982	11,130	11,115	10,095	11,793	13,532	13,199	11,791	10,517	9,657	11,351	13,309	13,679	12,504	11,927
AOP15	220	-131	-1,325	-173	356	525	433	1,463	1,513	765	-422	-1,204	-1,688	-554	-43
AOP16	399	-159	-1,261	119	686	436	1,043	1,159	760	1,182	166	-1,237	-2,585	-695	-70

Residual Hydro Loads in DOP14, DOP15 and DOP16

- DOP hydro load shapes for DOP14, DOP15 and DOP16 are shown below.
- The source of the operating criteria in the DOPs are their respective AOPs prepared 6 years in advance.

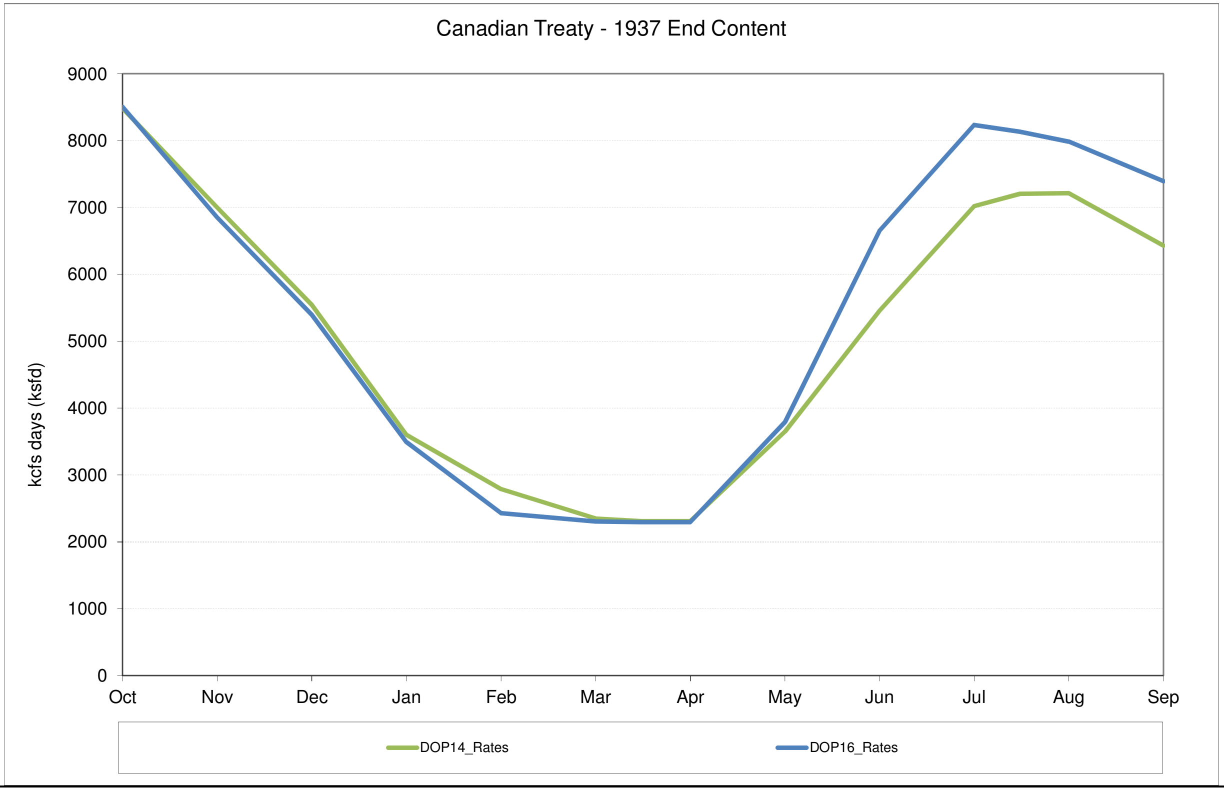


System - Residual Hydro Load (aMW)

	October	November	December	January	February	March	April I	April II	May	June	July	August I	August II	September	Annual
DOP14_Rates	10,013	11,685	13,467	13,035	11,692	10,467	9,548	11,253	13,122	13,663	12,503	10,930	11,082	11,067	11,846
DOP15_Rates	-91	465	590	597	1,562	1,563	874	-324	-1,017	-1,672	-553	286	-64	-1,276	40
DOP16_Rates	204	804	514	1,238	1,295	832	1,206	197	-1,099	-2,620	-680	462	-117	-1,161	12

Canadian Storage Operation (Mica+ Arrow + Duncan) in the Detailed Operating Plan Studies

- As shown below, in 1937 Canadian storage started the year at about the same content in both DOP14 and DOP16, however it was drafted more deeply (about 960 ksfd) at the end of the year in the DOP14. This draft is typically driven by load.

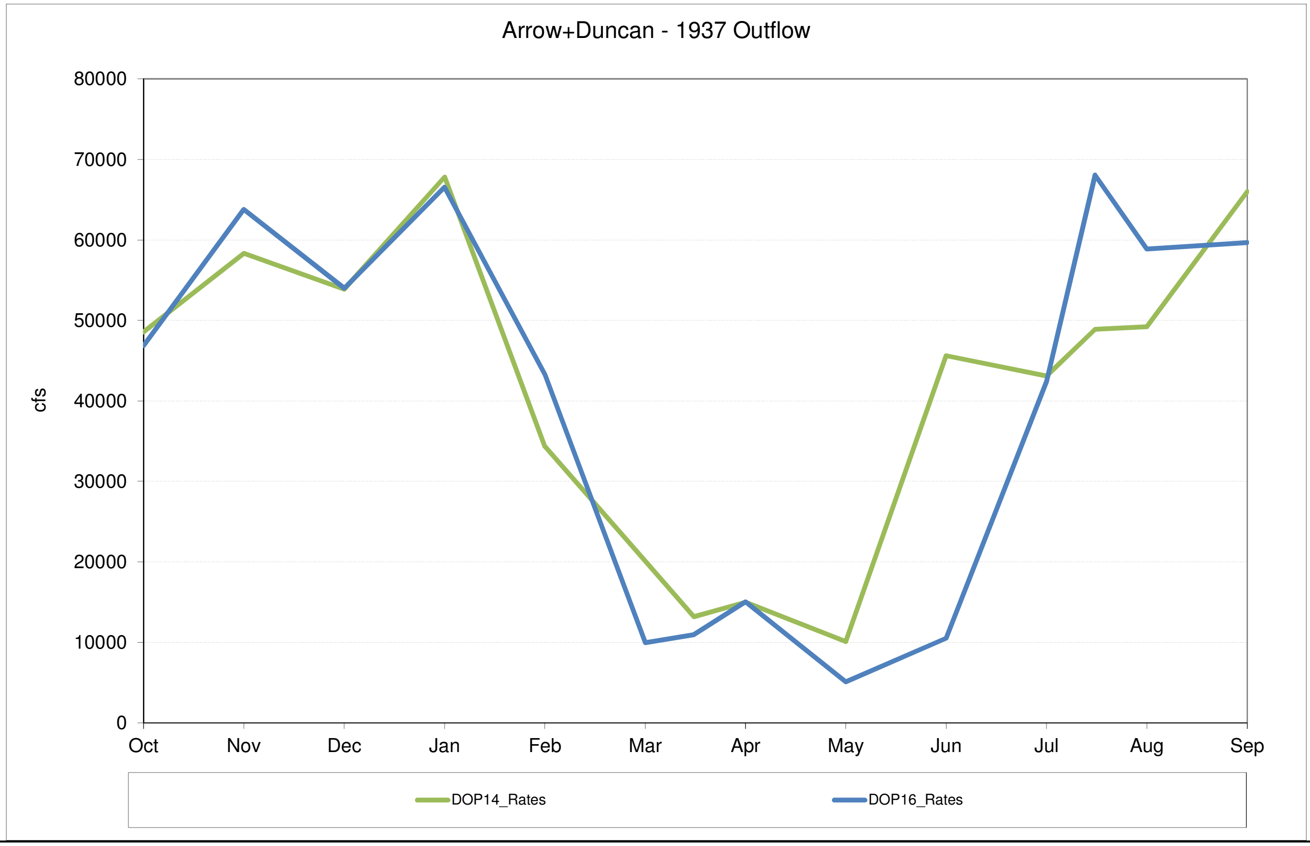


Canadian Treaty - End Content (kcfs days (ksfd))

	October	November	December	January	February	March	April I	April II	May	June	July	August I	August II	September	Annual
DOP14_Rates	8,484	7,001	5,544	3,603	2,790	2,352	2,309	2,310	3,647	5,458	7,020	7,206	7,214	6,430	5,172
DOP16_Rates	18	-146	-150	-111	-360	-47	-13	-14	141	1,194	1,215	927	772	962	299

Canadian Flows (Arrow + Duncan) in the Detailed Operating Plan Studies

- As illustrated in the graph below, Arrow + Duncan annual average 1937 flow difference between the DOPs is about 2.7 kcfs.

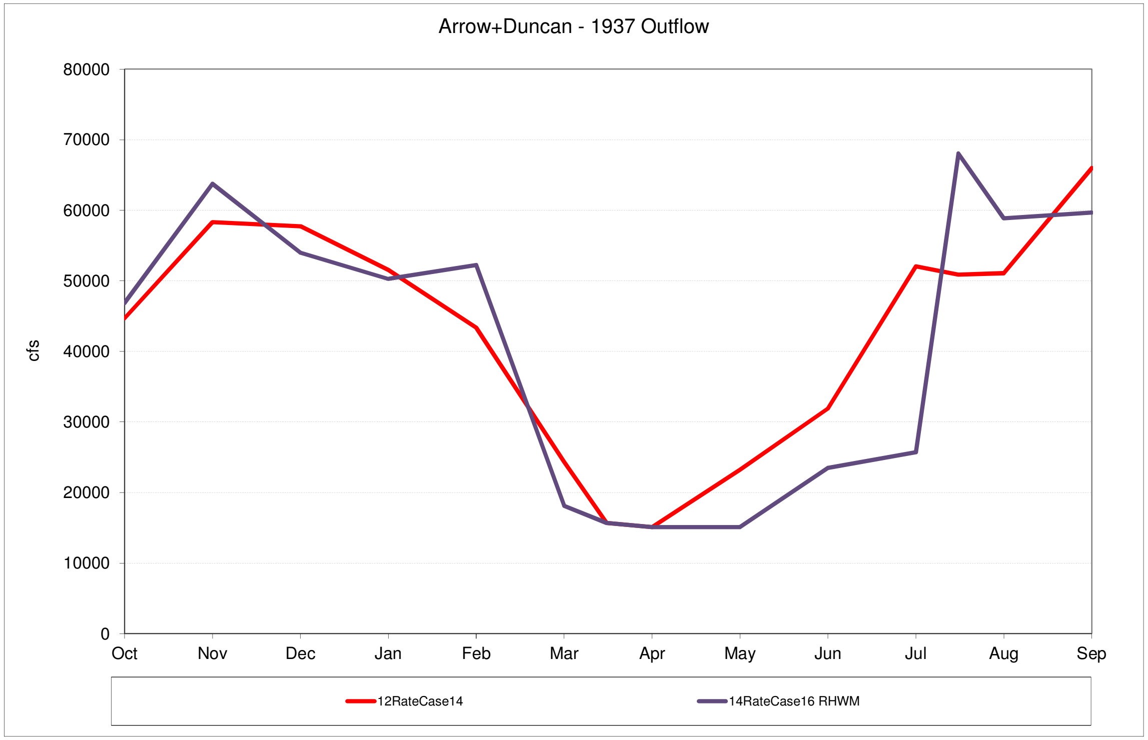


Arrow+Duncan - Outflow (cfs)

	October	November	December	January	February	March	April I	April II	May	June	July	August I	August II	September	Annual
DOP14_Rates	48,553	58,322	53,868	67,806	34,335	20,100	13,194	14,998	10,100	45,608	43,106	48,872	49,219	66,003	42,609
DOP16_Rates	-1,707	5,450	122	-1,260	8,909	-10,114	-2,228	39	-5,000	-35,078	-682	19,193	9,654	-6,329	-2,733

Canadian Flows (Arrow + Duncan) in two Rate Case Studies

- Differences come from two basic sources: 1) the underlying Treaty operation from the Assured/Detailed Operating Plans and 2) with-in year Treaty supplemental operating agreements and Non-Treaty storage agreement transactions.
- Differences in the DOP operations are reflected in the results from the Rate Case studies.



Arrow+Duncan - Outflow (cfs)

	October	November	December	January	February	March	April I	April II	May	June	July	August I	August II	September	Annual
12RateCase14	44,686	58,321	57,740	51,548	43,334	24,359	15,678	15,100	23,229	31,897	52,059	50,879	51,087	66,003	43,300
14RateCase16 RHWM	2,164	5,447	-3,749	-1,258	8,907	-6,242	0	0	-8,129	-8,397	-26,371	17,186	7,787	-6,330	-2,734

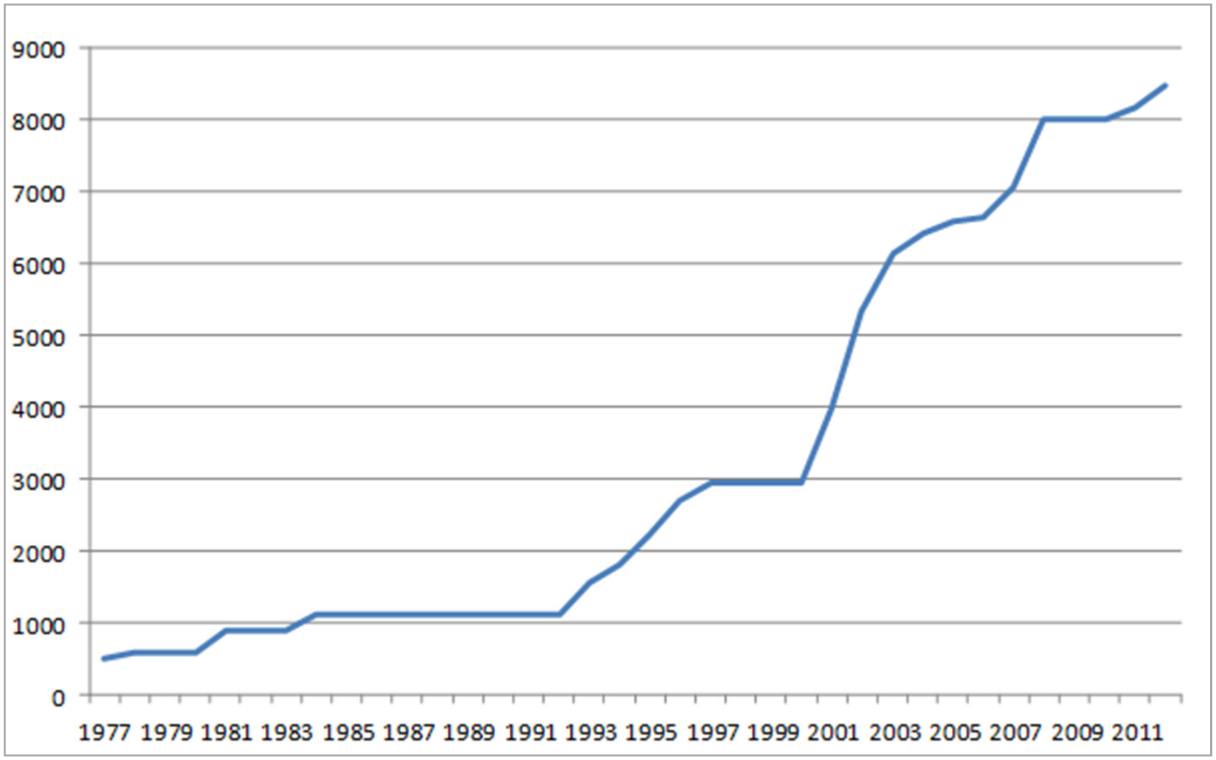
Gas Turbine Energy Capability Summary

Gas Turbines

- Two general types:
  - Combined-Cycle (includes steam generator) higher capital cost; but higher efficiency (slightly over 50%),
  - Single-Cycle (gas turbine only) lower capital cost but lower efficiency (35%).
- CTs have high level of reliability (manufactures report 95% and up), with maintenance and seasonal de-rates NERC GADS report around 90% availability – average annual (Council 6th Power Plan, Appendix I, page 72).
- The region has two major coal plant closures (Boardman and Centralia by 2020 and 2025). CTs will be a larger share of the regional resources stack.

Growth of Gas Turbines in the PNW

Total Cumulative Gas Fired Capacity in PNW (MW)



Utility Reporting of Gas Turbine Generation Forecasts

- CT generation forecasts submitted to PNUCC and incorporated in White Book and Rate Case for regional hydro regulation studies are inconsistent – as some forecasts report **full** energy capability while other CT forecasts reflect the economic dispatch of energy.
- **Peak** - Nearly all CT forecasts report monthly peaking capability (MW).
- **Energy** - Assumptions for the monthly energy estimates of CT combined-cycle and single-cycle projects vary by reporting entity:
  - Most entities report *Combined Cycle CT* forecasts at full monthly energy capability, however,
  - Some *Combined Cycle CTs* and most *Single Cycle CT* generation estimates have monthly economic dispatch forecasts. These forecasts do not reflect the true energy capability of these plants.

White Book, Rate Case, AOP, and the Future

- White Book is an inventory study, and should reflect the **full** thermal energy capability of thermal projects, not economic dispatch.
- Consistent with the White Book, the AOP uses the **full** thermal energy capability of CTs which is used to **displace** with non-firm hydro and therefore reduce the Canadian Entitlement.
- Beginning with the 2013 White Book, CT generation forecasts reflect the **full** energy capability based on NERC GADS data and thermal resource information from NWPPC's 6th Power Plan (Appendix I, page 72).
- These CT forecast procedures are already included in the White Book and Rate Case and will continue to be incorporated in future White Book and Rate Case Studies.

RHWM Process and Next Steps

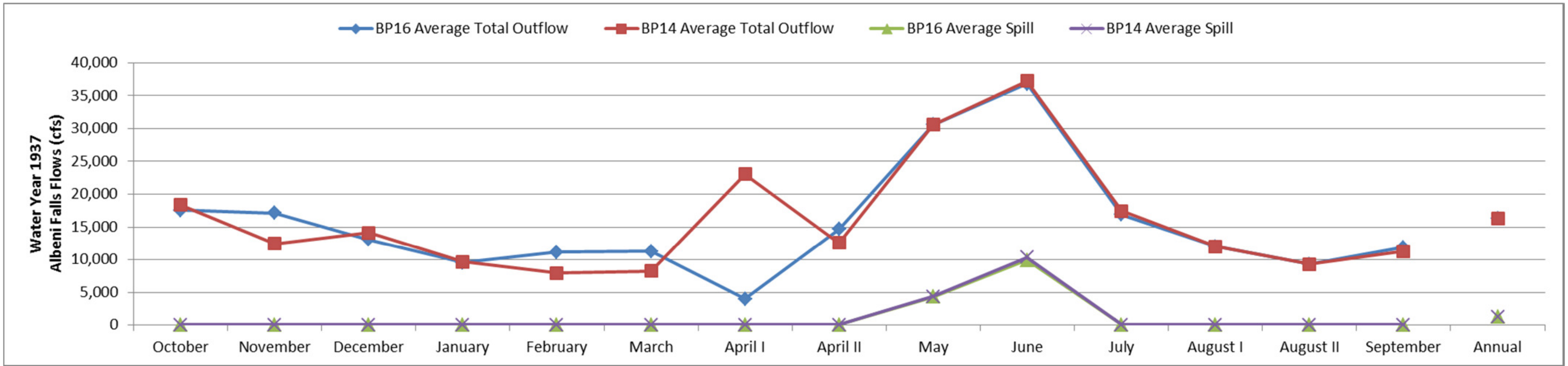
- Transparency
  - Additional data and explanations presented here as an effort to increase transparency and explain changes as clearly as possible.
  - Additional data posted to the external website with project specific monthly changes.

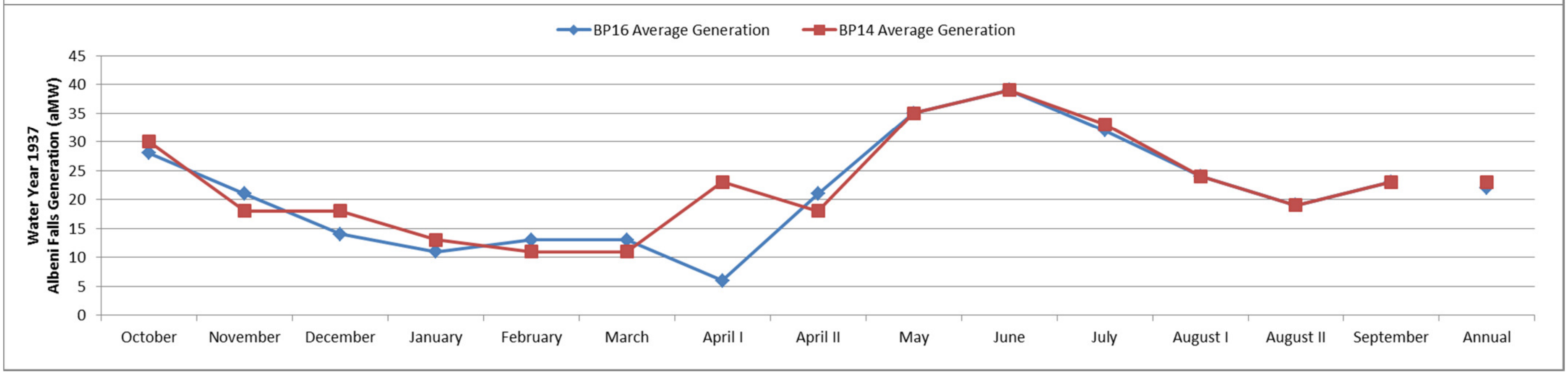
- Timing
  - Customer concern over length of comment period was expressed.
  - Desire to continue open regional discussion of these proposed changes in the Tier 1 system and associated impacts on RHWMs and customer rates.
  - Therefore, BPA is reopening the customer comment period for August 27 through September 4th.
  - For BP-18, BPA will consider revising the process to include a pre-Initial RHWM customer meeting to discuss changes in the Tier 1 System Firm Critical output.

- Next Steps
  - BPA will consider additional customer comments submitted, and will retain the September 9th workshop to discuss the RHWM process and final assumptions prior to posting final determinations in mid-September.

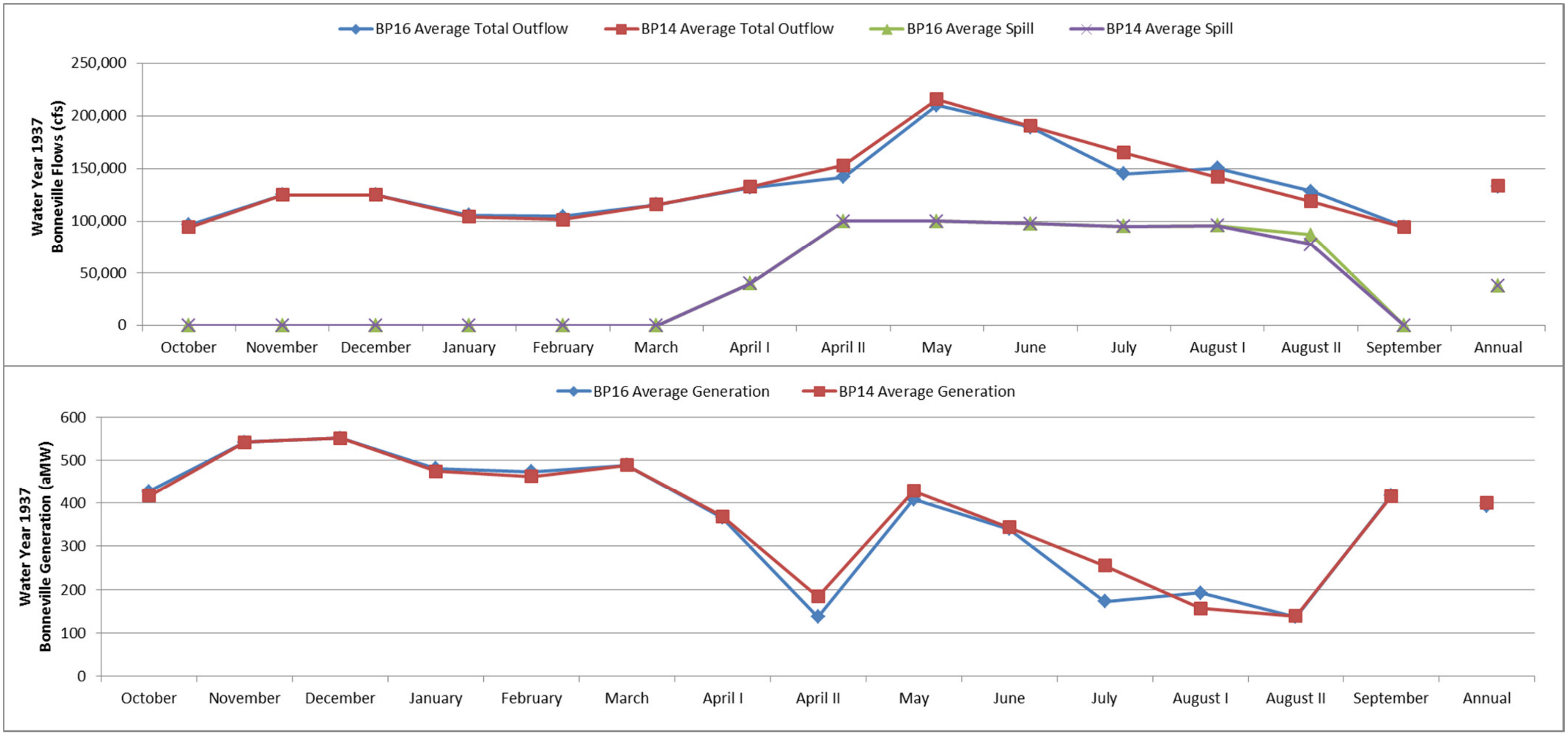
Appendix: Additional Data and Reference Material

Appendix: Albeni Falls



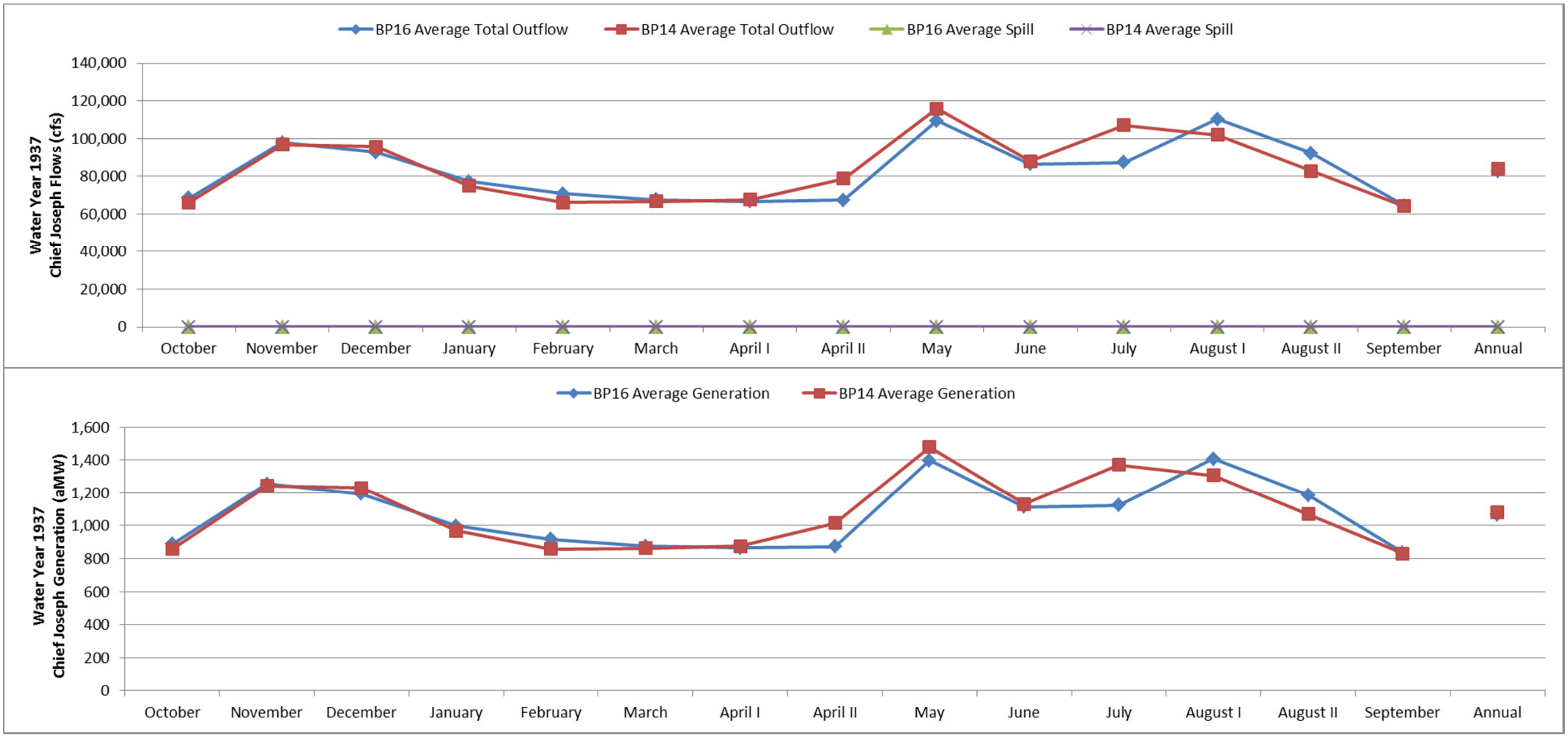


Appendix: Bonneville

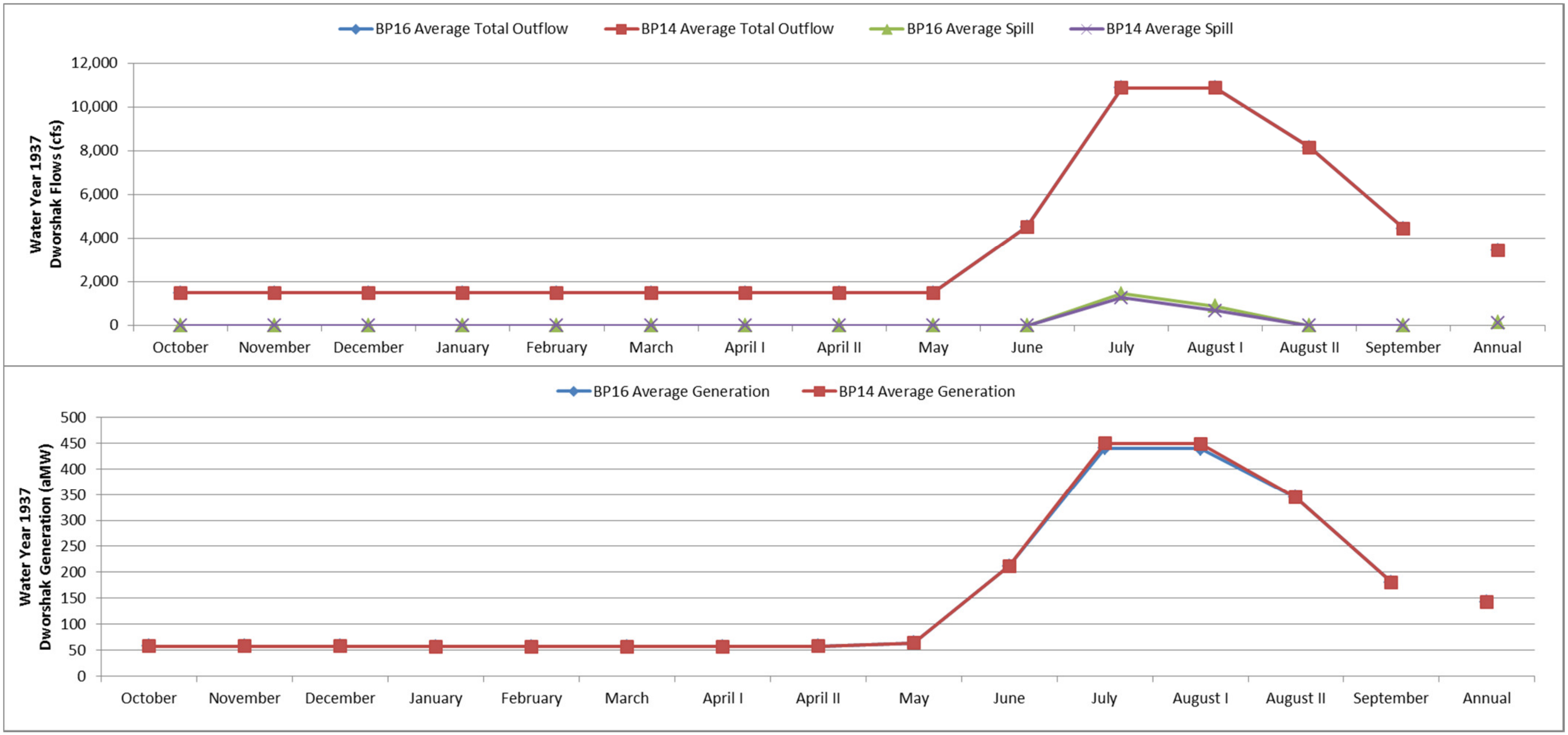


Pre-Decisional. For Discussion Purposes Only.

Appendix: Chief Joseph



Appendix: Dworshak



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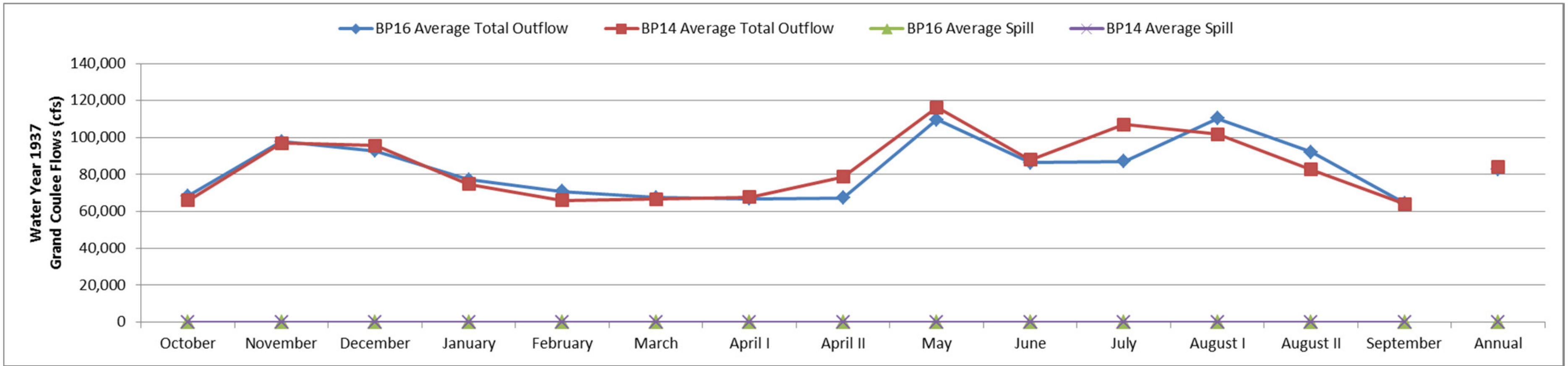
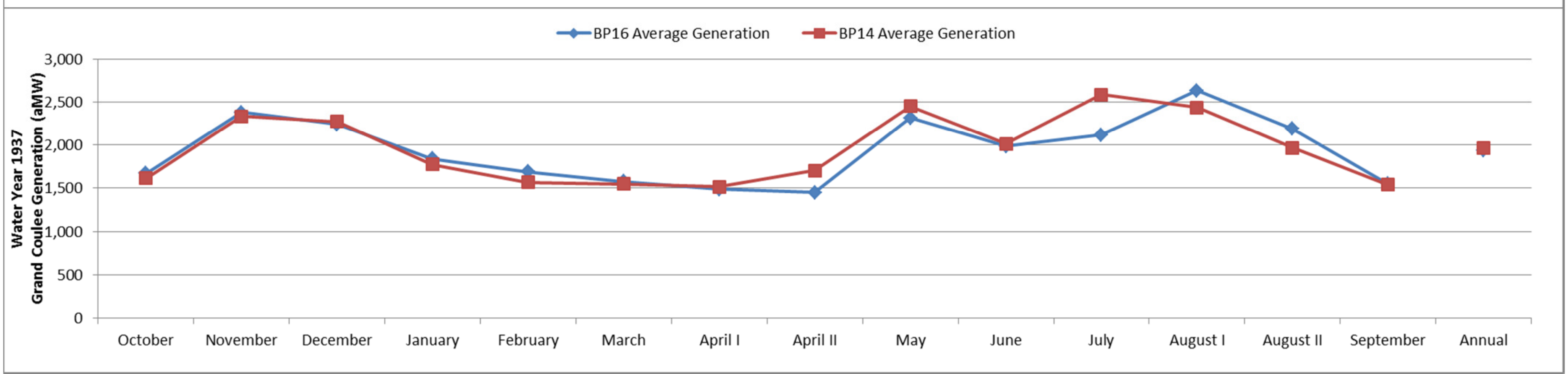
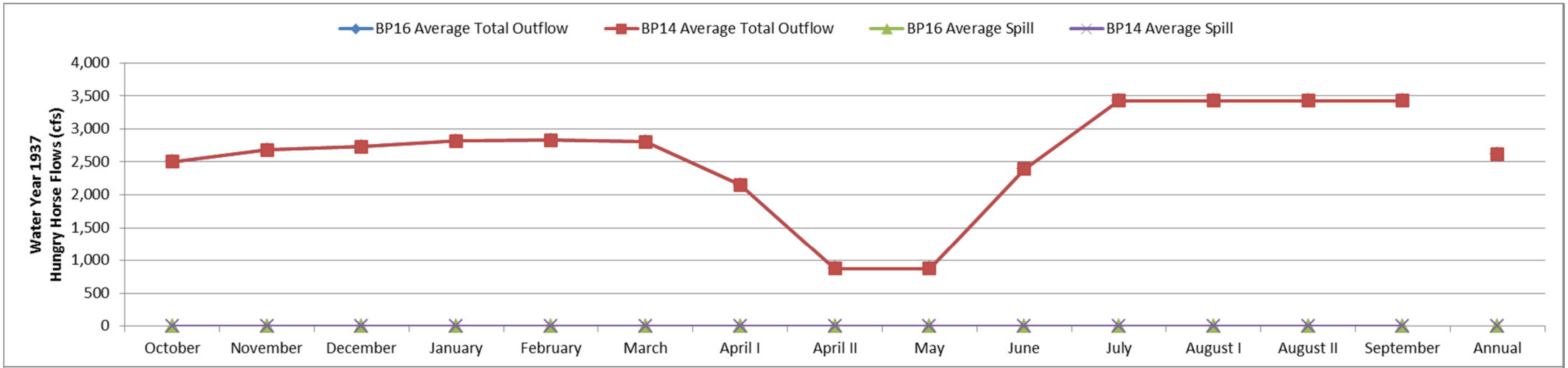
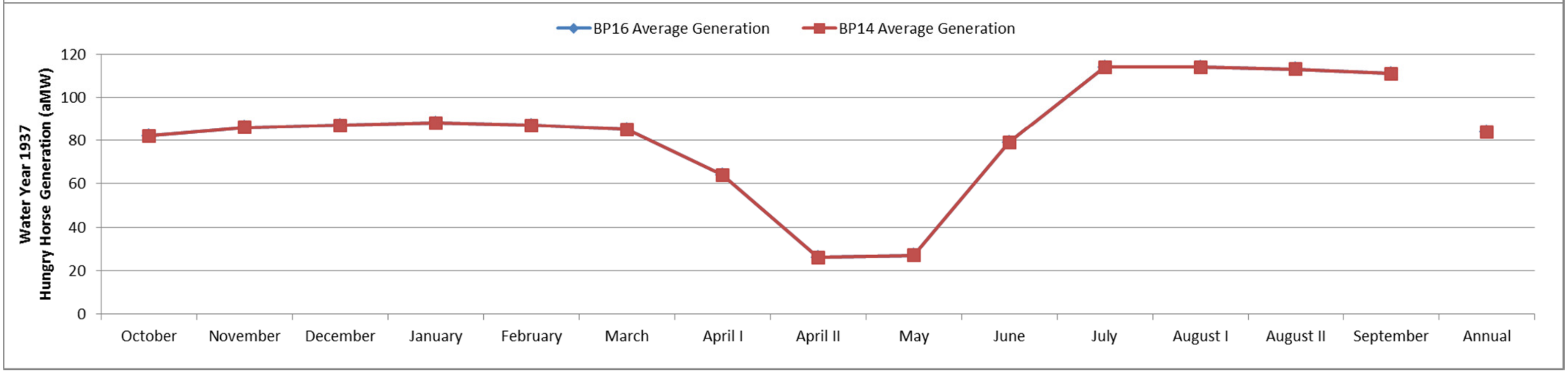
Appendix: Grand Coulee



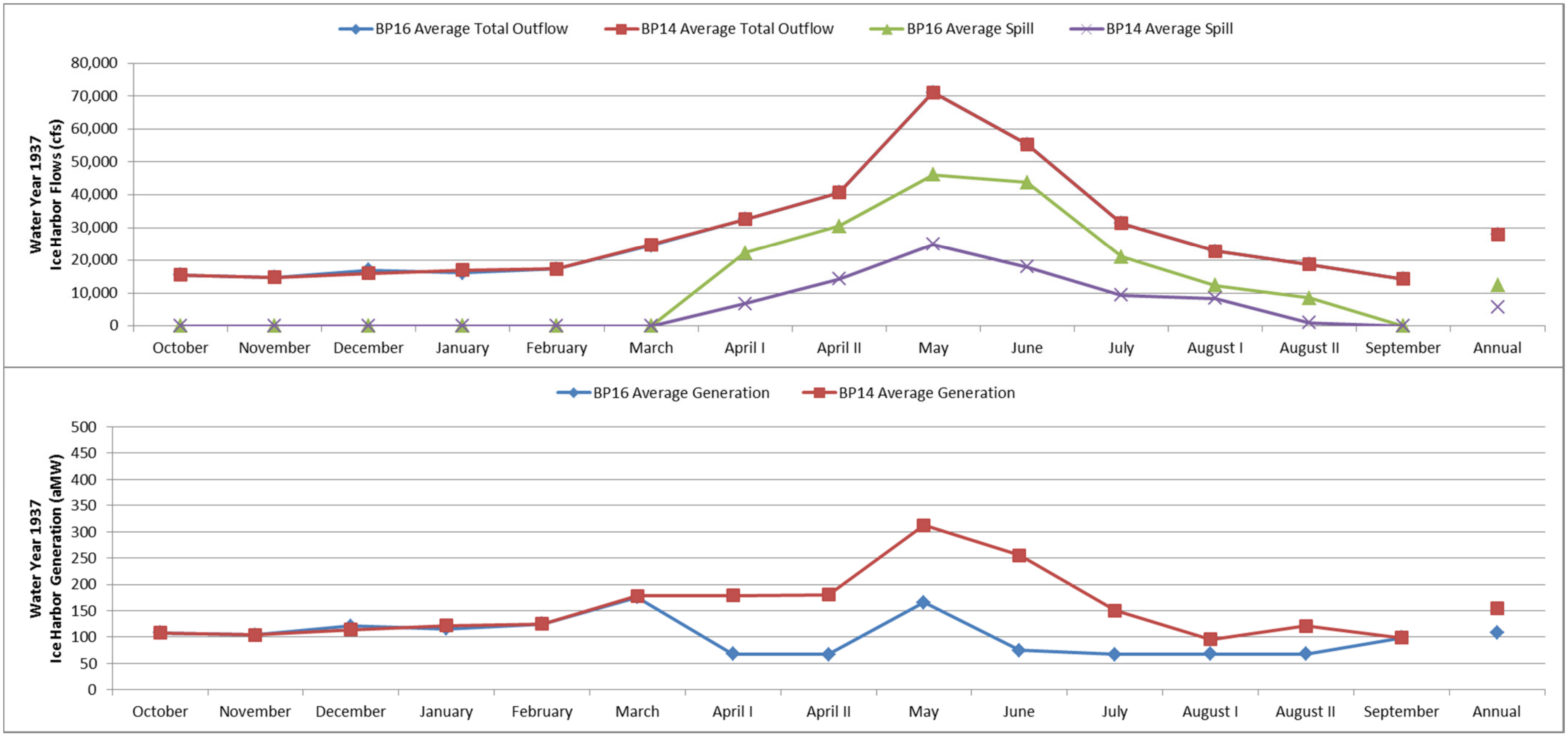


Appendix: Hungry Horse

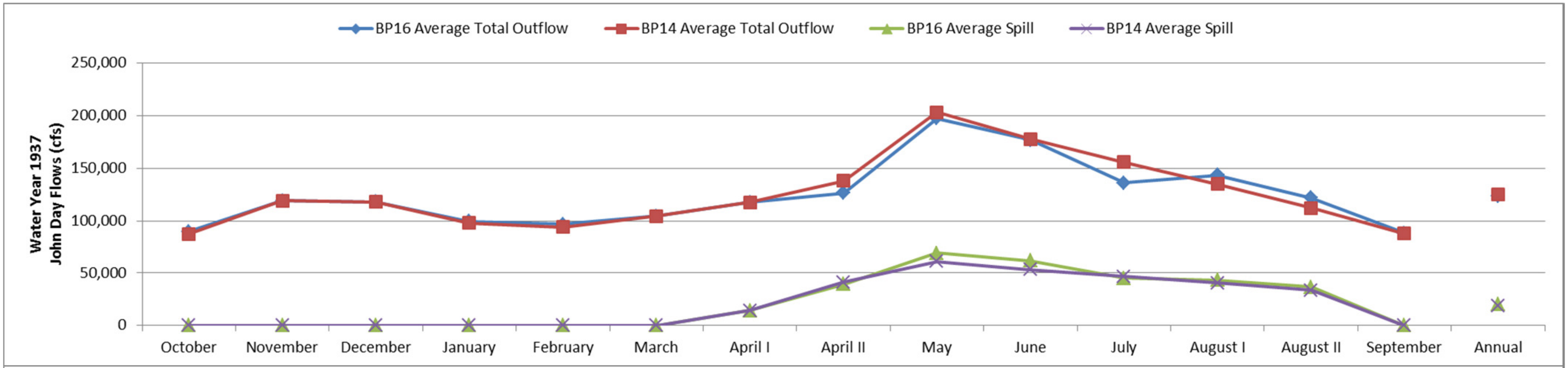


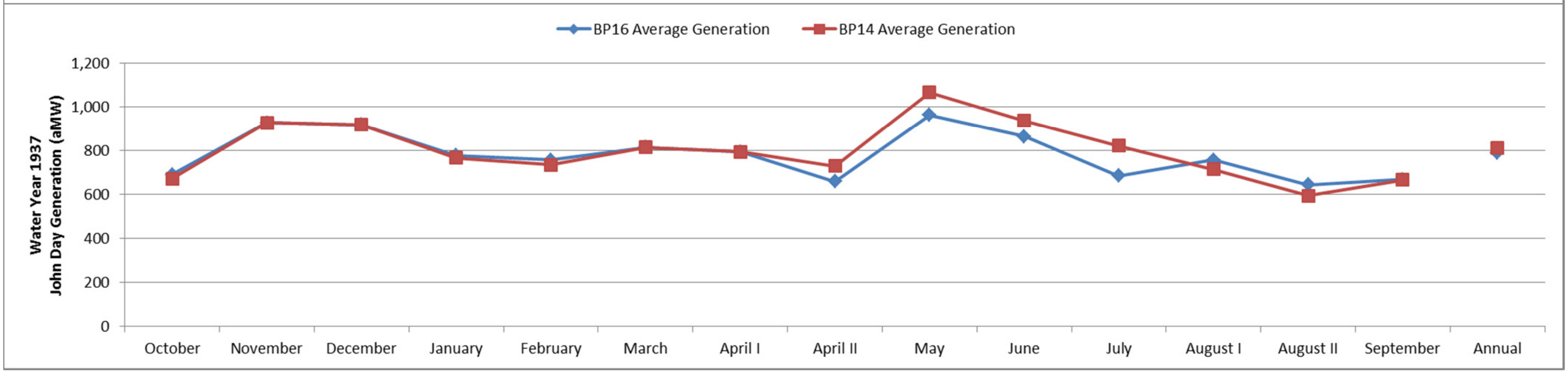


Appendix: Ice Harbor

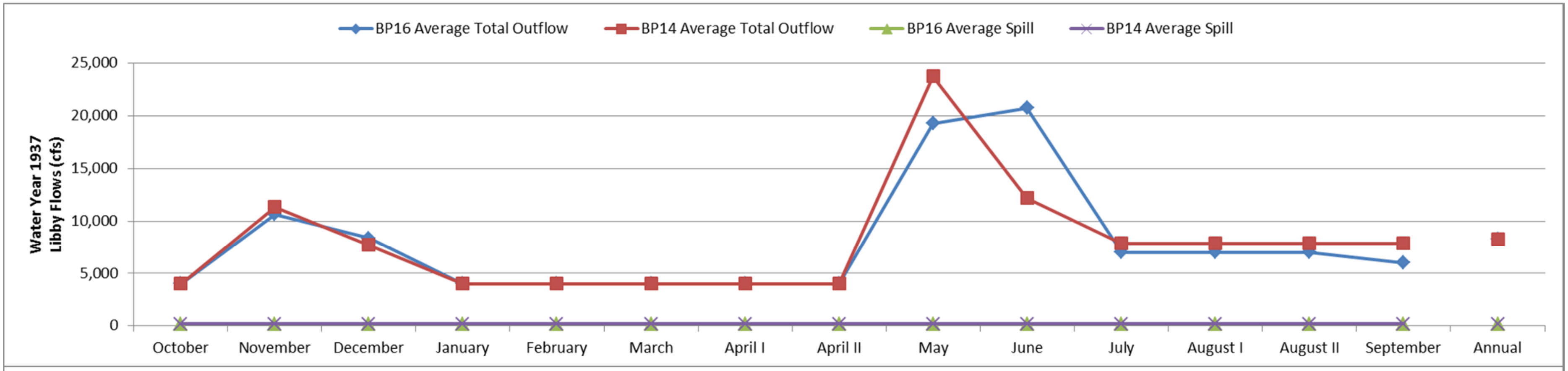


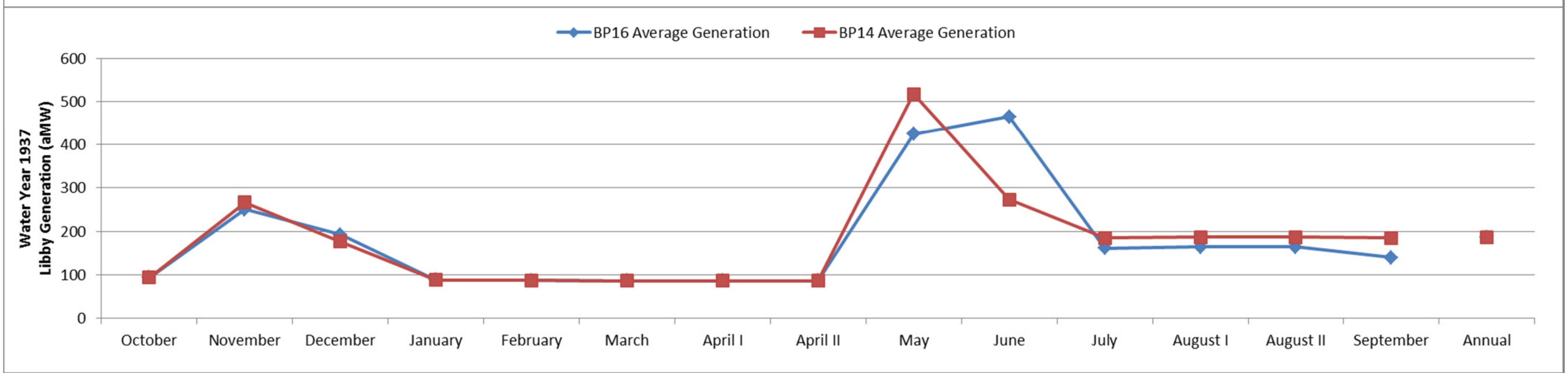
Appendix: John Day



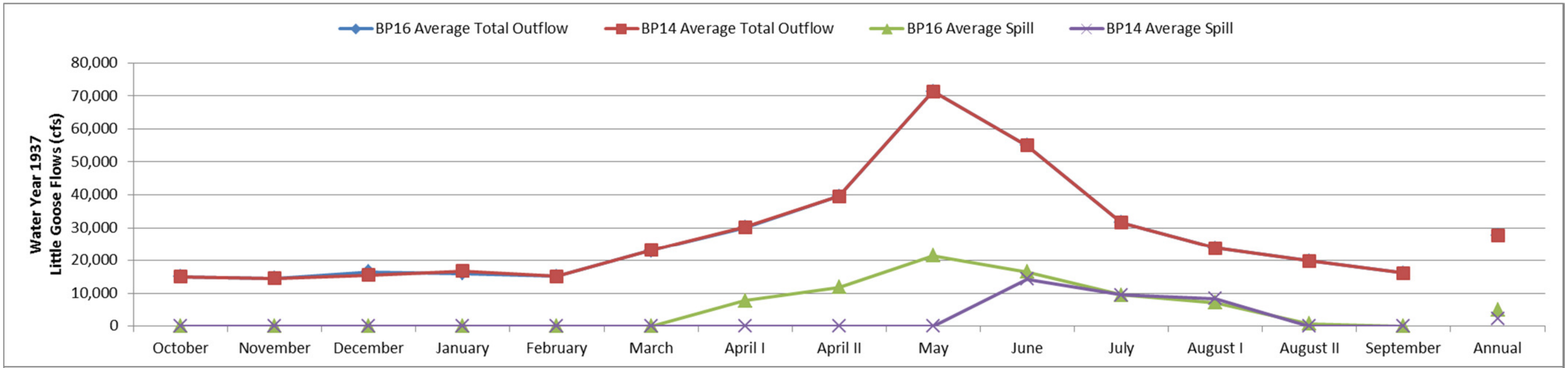


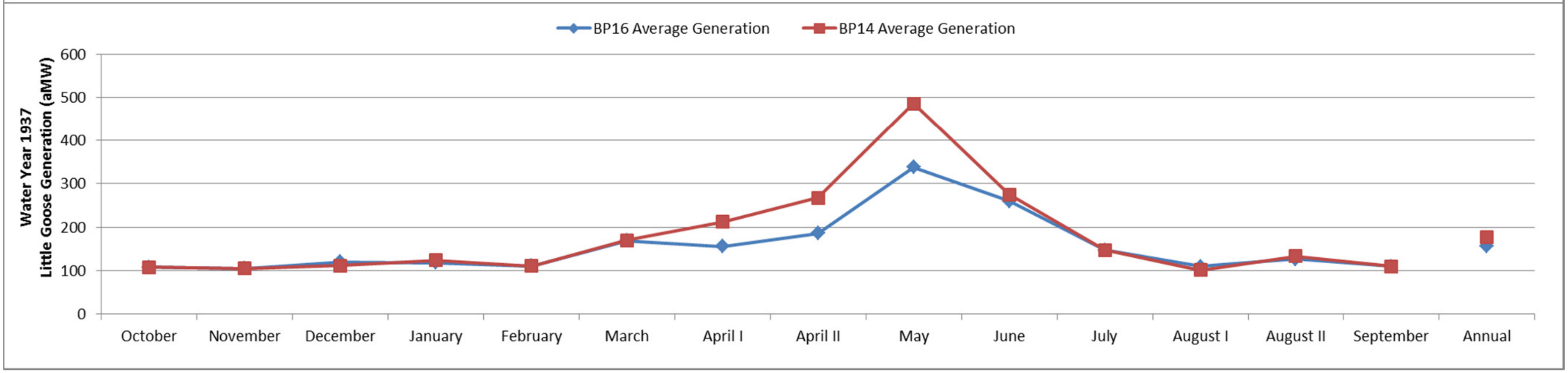
Appendix: Libby



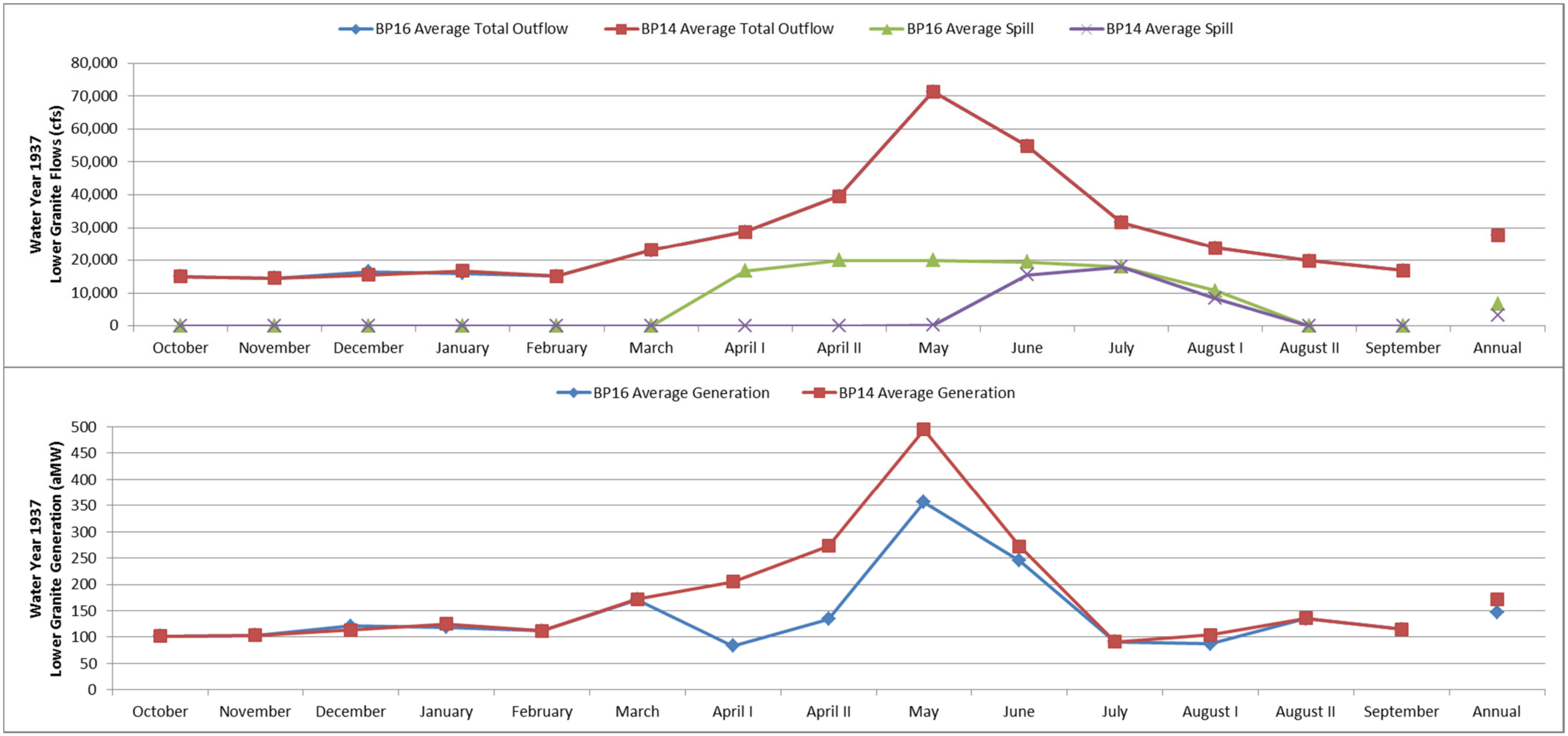


Appendix: Little Goose

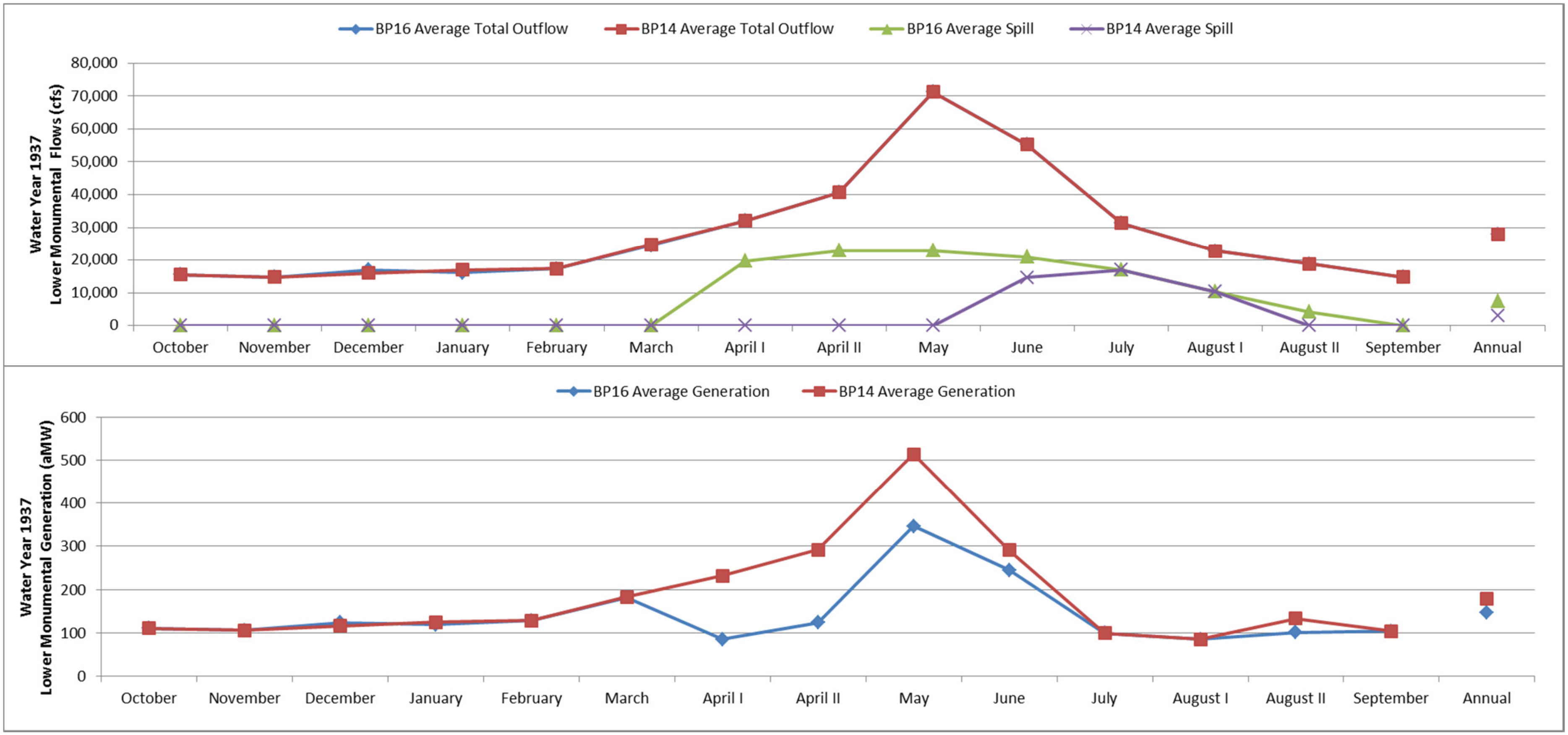




Appendix: Lower Granite



Appendix: Lower Monumental



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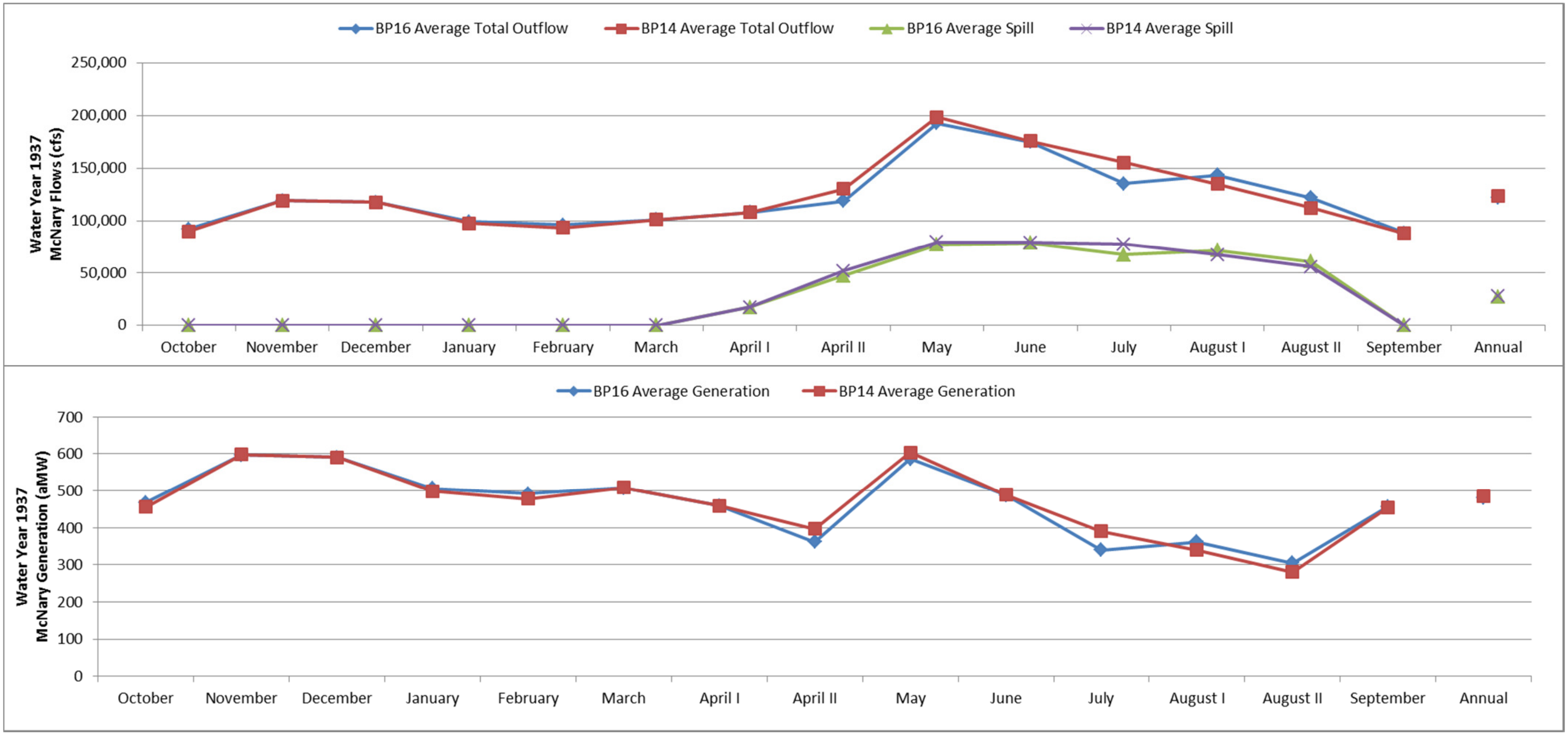
Appendix: McNary



Pre-Decisional. For Discussion Purposes Only.

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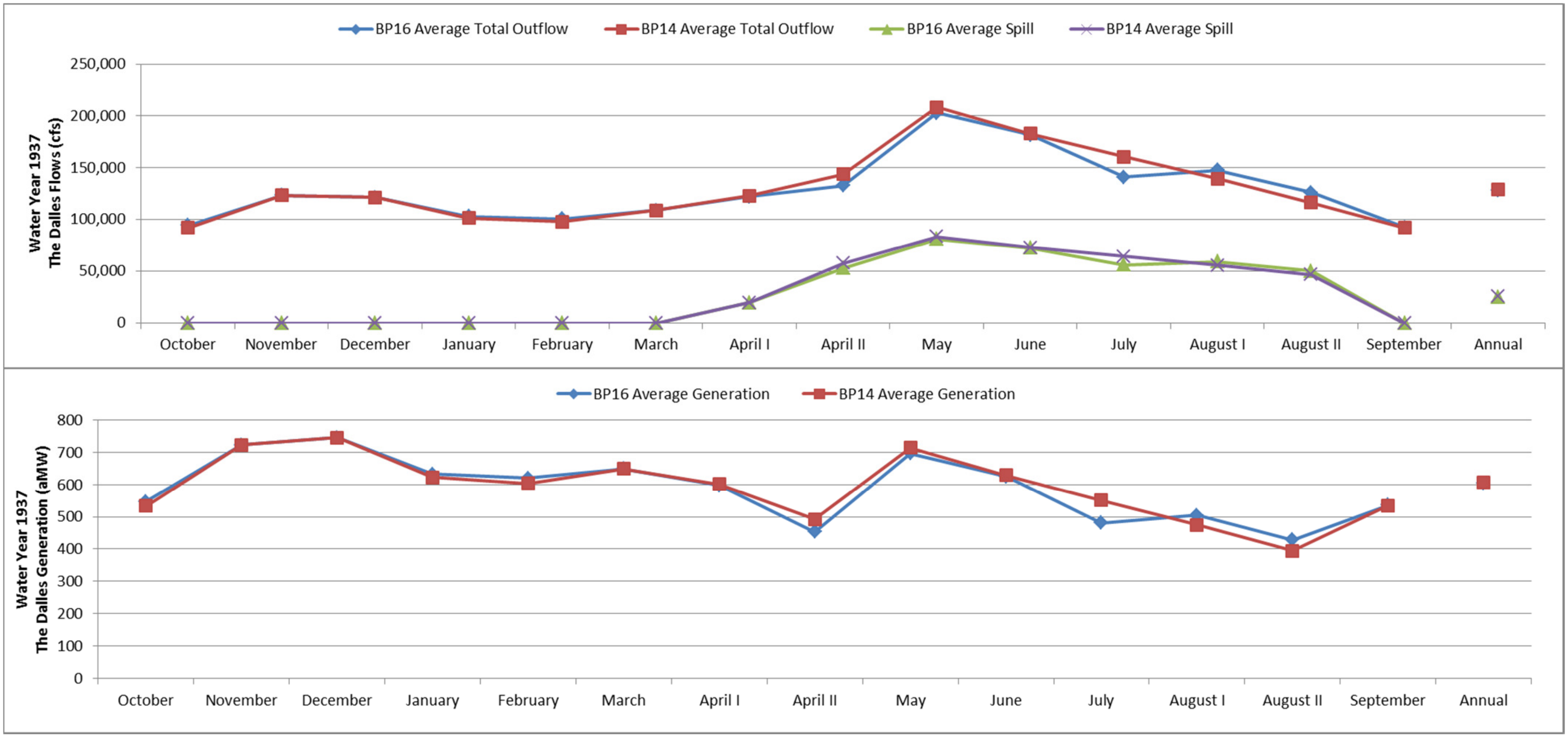
Appendix: The Dalles



Canadian Operations in Rate Case & T1SFCO Studies

AOP = Assured Operating Plan

- The 1964 Columbia River Treaty requires the US & Canada to develop an assured operating plan for operation of Canadian Storage six years in advance every year.
  - AOP16 for 2016 was published Sep 2011. AOP17 for 2017 was published Jan 2012.
  - BPA staff are currently working on AOP20 for 2020.
- AOP studies follow the protocol defined in the Treaty for an AOP to achieve an optimal power and flood control operation for the US & Canada.
  - The HYDSIM study follows standard utility practice to balance loads and resources.
    - AOP loads are based on Pacific Northwest Area loads as defined in the Treaty.
    - BC Hydro insists that these be our published White Book loads, not just an informal BPA forecast.
    - AOP16 & AOP17 loads came from the 2010 White Book.
    - Additional mutually-agreeable adjustments are made to balance loads & resources in the AOP, such as including California & Canadian imports to balance when the study has deficits.
  - The study does not include most modern non-power requirements, so the AOP does not reflect actual operations for US projects.
  - Because the AOP balances loads & resources and does not include most non-power constraints, the load assumption significantly affects the AOP.

Unlike our Rate Case study, which reflects actual operations and is so constrained by non-power operating requirements that the load does not have a significant affect.

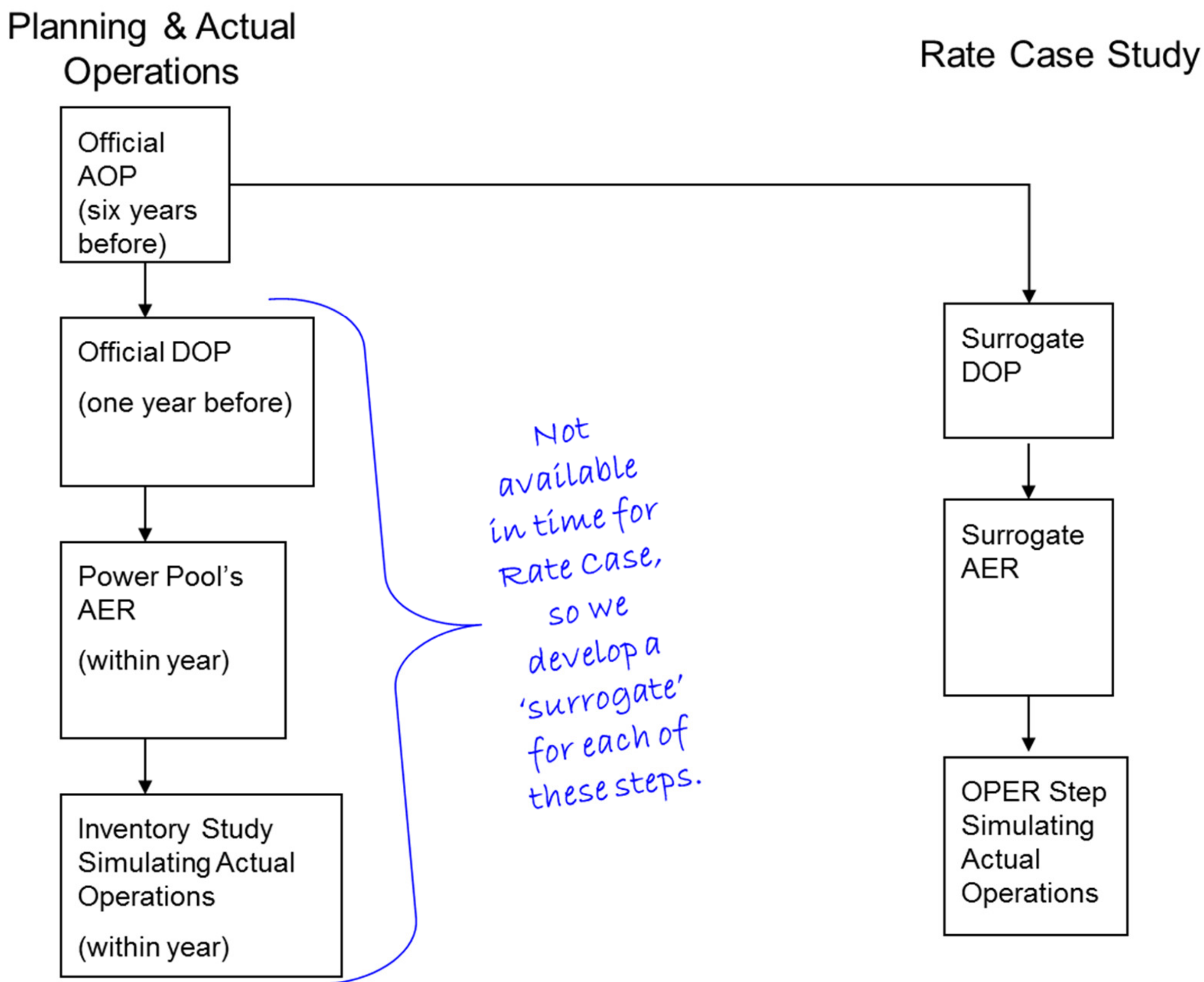
- The AOP study results determine the monthly power & flood control planning operations for Canadian storage, unless otherwise agreed (i.e. in the DOP or in annual operating agreements).
- The Canadian Entitlement is also determined in the AOP.
  - Under the Treaty, the Canadians are entitled to half of the downstream power benefits resulting from Treaty storage operations.
  - The Canadian Entitlement is set by the AOP study and is not updated or modified for differences in the DOP or annual operating agreements.

Canadian Operations in Rate Case & T1SFCO Studies

DOP = Detailed Operating Plan

- DOP is completed the year prior to the operating year.
  - Unfortunately, this means these studies are not available early enough for our T1SFCO studies or Rate Case studies.
  - For instance, the 2015 DOP was published in June 2014, but the Rate Case study for 2015 was initiated in July 2012 and completed in April 2013.
- DOP is an optional refinement of the AOP:
  - Only reflecting mutually agreeable updates,
  - Typically only includes minor changes,
    - Updated flood control procedures
    - Updated stream flow procedures
    - Updated plant data
    - Updated hydro independent data
- DOP is the study that gets used in the PNCA planning process, i.e. the studies run by the Northwest Power Pool.
- Since the official DOP is not available early enough for the Rate Case studies, we use a surrogate study.

Canadian Operations in Rate Case & T1SFCO Studies



Canadian Operations in Rate Case & T1SFCO Studies

What really gets input to the Rate Case study?

The DOP surrogate determines Canadian operations for the AER step.

- Surrogate DOP
  - We need an approximation of the DOP before the official DOP is available, sort of surrogate DOP study that is only for the Rate Case.
  - We start with the AOP – the official AOP is available for the rate period years.
  - We change this to a forecast-based study for fiscal year instead of a perfect knowledge study running August-July.
  - We update Canadian operations following the same process that will be used in the official DOP:
    - Update plant data with most recent PNCA data
    - Use the most recent streamflow data available (80-yr 2010 modified streamflow)
    - Update flood control using most recent assumptions & procedures from the Corps of Engineers

The AER step determines non-Federal operations for the OPER step.

- AER Step
  - We use the resulting Canadian operations from the surrogate DOP study in our AER step.
  - We use the PNCA planning data for all projects.
  - We run this step of the study similar to the Power Pool's AER study used for PNCA planning.
  - This step is used to estimate the operations of all the non-federal projects.

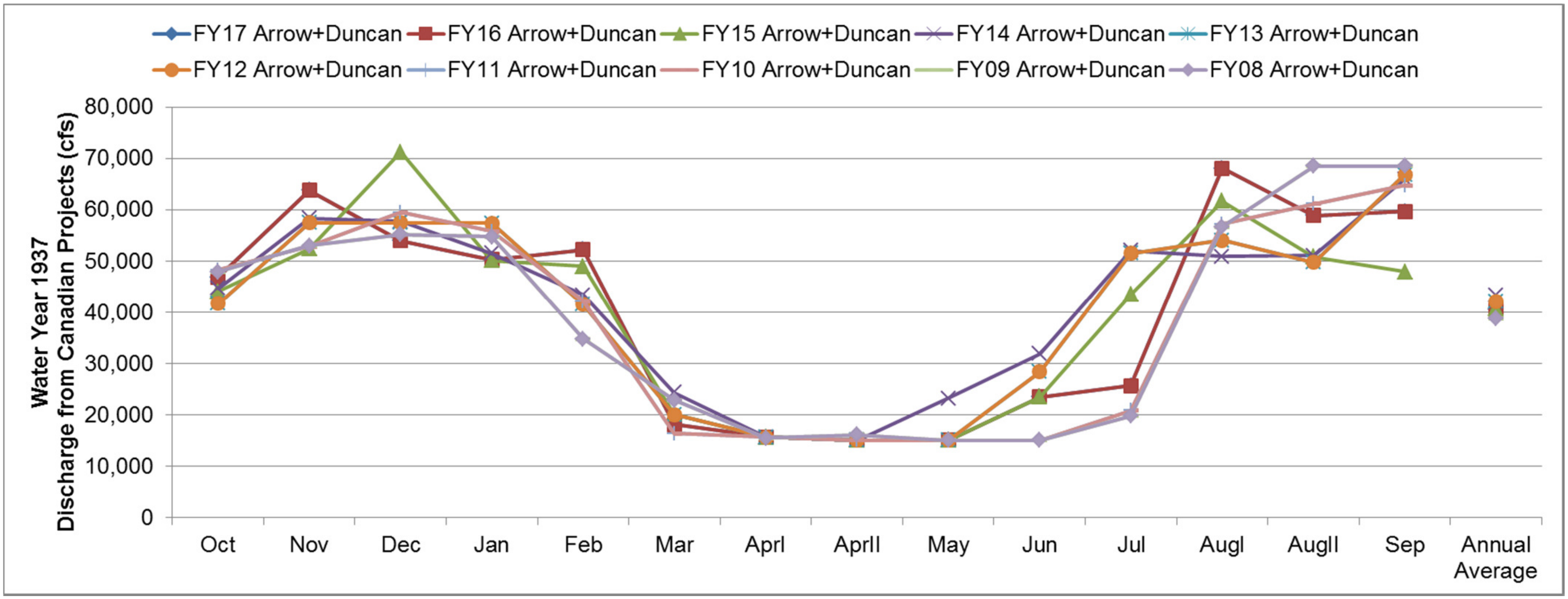
The OPER step determines Federal operations for the generation estimates used in our Rates & T1SFCO studies.

- OPER Step
  - This step is similar to the AER step but includes more refinements to better reflect expected actual operations.
  - We use the resulting US non-federal project operations from the AER step.
  - We add refinements at the federal projects where the PNCA data is either too generic or outdated.
  - We add expected Canadian operations that are not reflected in the DOP:
    - Biological Opinion flow augmentation of 1 maf
    - Arrow trout spawning logic
    - Whitefish operation downstream of Arrow
    - Non-Treaty Storage Agreement

Canadian Operations in Rate Case & T1SFCO Studies

How much do the Canadian Operations change in our Rate Case studies?

- The chart below shows the 1937 critical year Canadian project outflow from our past few Rate Case studies and the recent T1SFCO studies for FY16 & FY17.
- The operations do change from year to year in these studies.
  - The overall shape appears to be relatively consistent with the most variation in the summer months.
  - The average annual discharge ranges from about 39,000 to 43,000 cfs.



Updates in the BP-14 HYDSIM Rate Case Studies

BP-14 Initial compared to the BP-14 RHWM Studies.

- Minor Updates
  - New flood control data is not available from the Corps as previously expected, because the Treaty work has kept them from completing this analysis.
  - Reserve Requirements
    - Operating Contingency Reserves: 3% of load and 3% of generation.
    - Balancing Reserves: 30min wind persistence, 60min scheduling, with self supply, and committed intra-hour scheduling, maxed at 900 MW.
    - These assumptions do not affect HYDSIM results significantly, especially in dry years, but will affect HOSS heavy/light ratios.
  - Residual Hydro Load Forecasts
    - Does not affect HYDSIM results significantly, especially in dry years.
  - Brownlee operations are based on the Corps' 80-year modeling for PNCA data submittal.
  - Removed Grand Coulee gate maintenance operation from FY14 study, because maintenance is not required that year.
- Non-Treaty Storage Agreement's spring-summer reshaping provision.
  - The FY12-FY13 Rate Case did not include non-Treaty storage operations.
  - Tier 1 study only included the dry year provision.
  - Spring-summer NTSA provision allows us to store water in the spring if meeting BiOp flow objectives and release this water in July and/or August when the energy is more valuable.
- New Grand Coulee draft limit assumptions for HYDSIM
  - These are not new actual operating requirements but an update to modeling assumptions reflecting likely in-season management decisions when all operating objectives cannot be met.
  - Instead of drafting aggressively when needed to meet chum flows & Vernita Bar flows during Jan-March in our studies.
    - Draft only to 10 feet below the fish VDL for chum flow requirements below Bonneville The fish VDL is a variable draft limit calculated to ensure 85% chance of being at the April flood control elevation.
    - Draft further for Vernita Bar if necessary, but no lower than elevation 1260 in Jan, 1250 in Feb, 1240 in March & April.
  - These assumptions appear to provide a slight increase in generation, ~20aMW in 1937 and ~40aMW in 80-year average.
- Lack-of-Market Spill
  - Significant decrease in May and June.
  - Numerous updates in AURORA have caused this change.

Primary Drivers of Monthly Federal Generation Differences Under 1937 Water Conditions

- **April II (Second Half of April)**
  - Changes in spill at the Lower Snake projects & John Day reduces their generation. These spill changes include not modeling the Spring Maximum Transport in Dry Years operation as well as assuming the test operations shown in the 2014 BiOp spill table for Ice Harbor & John Day.
  - In the current studies, Albeni Falls operates to a lower winter elevation than in the previous Rate Case, resulting in additional fill at Albeni Falls in April that reduces its outflow. This, along with passed through flow changes from Kerr in April, reduces generation at all downstream projects (Grand Coulee – Bonneville).
- **May**
  - Changes in spill at the Lower Snake projects & John Day reduces their generation due to the same reasons listed above under April II.
  - Delayed sturgeon pulse start from mid-May to June 1st at Libby reduces its generation and outflow in May. The passed through flow change from Libby combined with less outflow from Canadian projects reduces generation at all downstream projects (Grand Coulee – Bonneville).
- **June**
  - Changes in spill at the Lower Snake projects & John Day reduces their generation due to the same reasons listed above under April II. However, the generation reductions at Lower Snake transport projects are not as large because these projects transition to summer spill in June, so the previous Rate Case included some spill for these projects.
  - Delayed sturgeon pulse start from mid-May to June 1st at Libby increases its generation and outflow in June. The passed through flow change from Libby partially offsets the lower outflow from Canadian projects.
- **July**
  - Changes in spill at Ice Harbor & John Day reduces their generation. These spill changes are due to assuming the test operations shown in the 2014 BiOp spill table.
  - Substantial decrease in outflow from Canada reduces generation at all downstream projects.