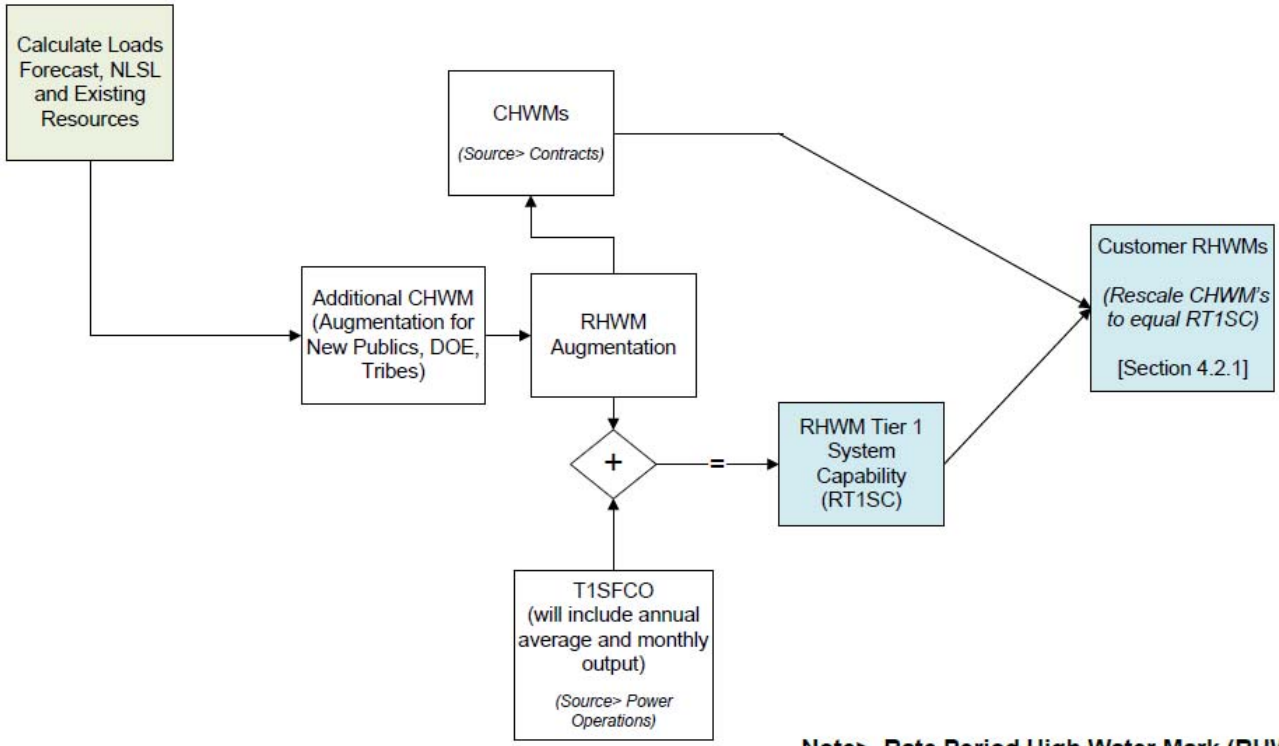
RHWM Process Workshop
May 8th
9:00-12:00

Rates Hearing Room

RHWM Process Workshop Agenda
May 8th - 9:00 to 12:00

Topic	Presenter
Intro and Purpose of Workshop	Stiffler
Part 1	
RHWM Process + Process and Timeline	Bliven/Stiffler
Part 2	
Tier 1 System Firm Critical Output (T1SFCO)	
• Changes from BP-12 - HYDSIM	Fodrea
• Annual Firm Wind Energy	Llewellyn
• T1SFCO Study Results	Misley
Part 3	
RHWM Computation Examples	Stiffler
Discussion: •Tradeoff in planning certainty and accuracy of Above HWM load forecast •Other topics?	All
Next Steps: •Publish draft RHWM outputs June 1, 2012 •Customer review of numbers in advance of June 12, 2012 Workshop.	Bliven/Stiffler

RHWM Process

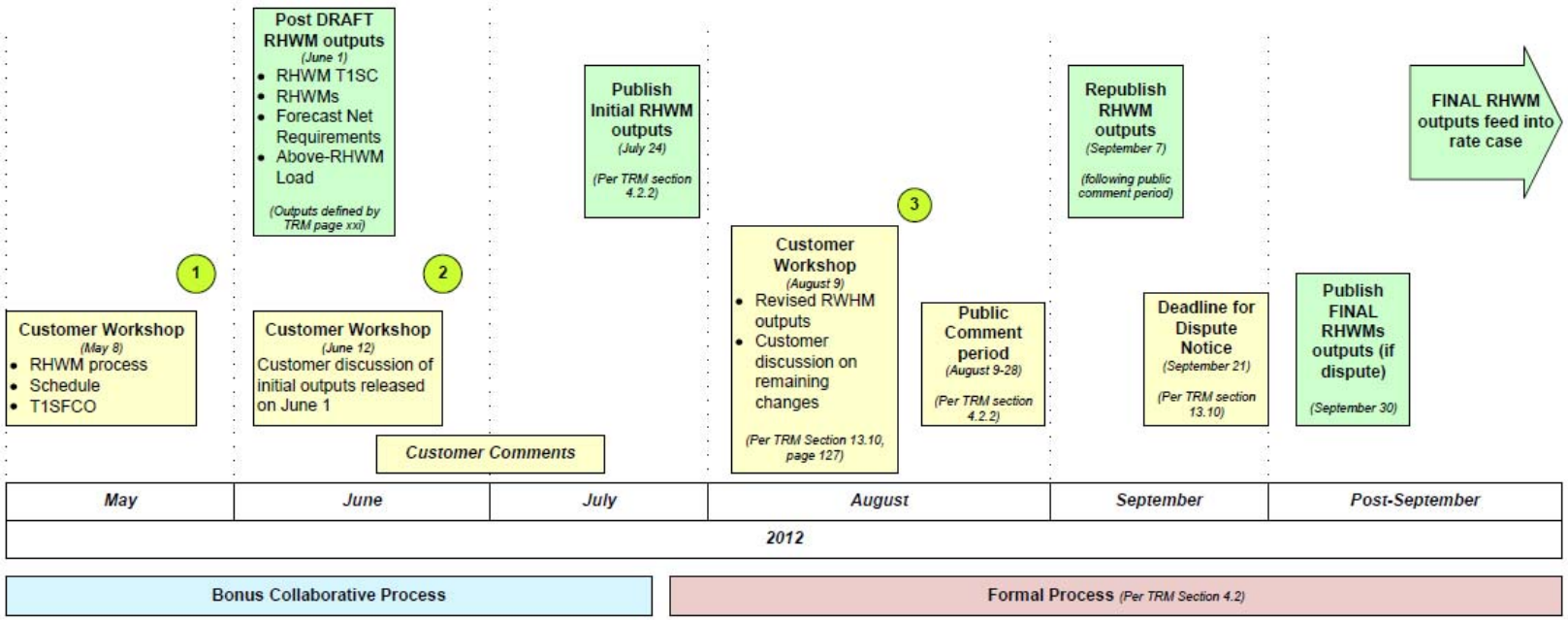


2014 RHWM Calculations and Data Sources – Tiered Rate Methodology

Note> Rate Period High Water Mark (RHWM) will include the following outputs (*as noted in the Tiered Rate Methodology (TRM) on Page xxi)*:

- RHWM Tier 1 System Capability (including RHWM Augmentation)
- RHWM (by customer)
- Forecast Net Requirement (by customer)
- Above-RHWM load (by customer)

RHWM Timeline



Workshop Objectives

Workshop #1 Objectives

1
- Review RHWM process with customers
- Review schedule and milestones
- Present and discuss Tier 1 System Firm Critical Output (T1SFCO)

Workshop #2 Objectives

2
- Address Customer RHWM process questions (*Goal: To work through as many questions and issues before the formal process begins*)
- Review RHWM formal process schedule
- Discuss public comment period process
- Discuss dispute process (including dispute notice deadline)
- Method of communication for customers filings (Comments, Dispute Notices – how to file, applicable filing deadlines if customers have comments or disputes)

Workshop #3 Objectives

3
- Begin formal RHWM Process

FY 2014-2015 T1SFCO for RHWM
May Customer Workshop

Tier 1 System Firm Critical Output

Agenda

- Review T1SFCO Study
  - Explain differences since BP-12
  - Present new annual firm wind methodology
  - Present T1SFCO study results

Next Few Slides

Federal Tier 1 System Firm Critical Output

- HYDSIM Study Updates Since the BP-12 Final Proposal Study
  - Canadian Operations
    - Canadian operations were updated based on 2014 and 2015 Annual Operating Plans (Treaty AOP studies). The Canadian project operations changed based on the loads in the AOP studies.
    - The dry-year provisions from the new Non-Treaty Storage Agreement were reflected in the study. This allows an additional 0.5 maf release from Mica or Arrow during May or June of the driest 20% of years. This provision provides ~8kcfs additional flow in June of 1937.
  - 2010-level Modified Streamflows
    - 2010-level Modified Streamflows were incorporated into the study. The BP-12 studies used 2000-level modified flows.
    - Modified streamflow data sets are developed every ten years as required under the PNCA to reflect updated estimates of irrigation depletions and expand the data another ten years.
    - The 2010-level streamflows include less water than the 2000-level streamflows. More details on next slide
  - Brownlee Operations
    - The Brownlee operations were updated to be consistent with more recent operating assumptions targeting specific elevations each month while meeting minimum flow requirements. The previous rate case study's operating rules for Brownlee produced unreasonable results with the new reduced streamflow data.
  - 2012 PNCA Data
    - New Federal project data (H/K, storage tables, rating curves, etc.) and Miscellaneous minor flow requirement changes
    - The last Rate Case studies were based on 2010 PNCA data.
  - Availability Factors
    - Grand Coulee outages are based on 2011 actual average outages with 2 large units out of service in all months (~65% average availability, ~4% lower than BP12).
    - Chief Joseph outages are based on 2010-2011 actual average outages (~90% average availability, ~4% higher than BP-12).
    - Outages at all other federal projects are based on 2007-2011 actual average outages.
    - Reserve assumptions are nearly the same as BP-12 but are updated with the mid-December installed wind fleet forecast and the 3x3 standard for operating contingency reserves.
  - Updated Lack-of-Market Spill Estimates from AURORA Model
    - Used HOSS heavy/light ratios instead of generic AURORA heavy/light assumptions
    - Updated AURORA dispatch optimization logic
    - Higher load in FY14/FY15 than FY12/13 in AURORA
    - Used 30 wind profiles and 200 transmission profiles in AURORA instead of just using 2009 actuals

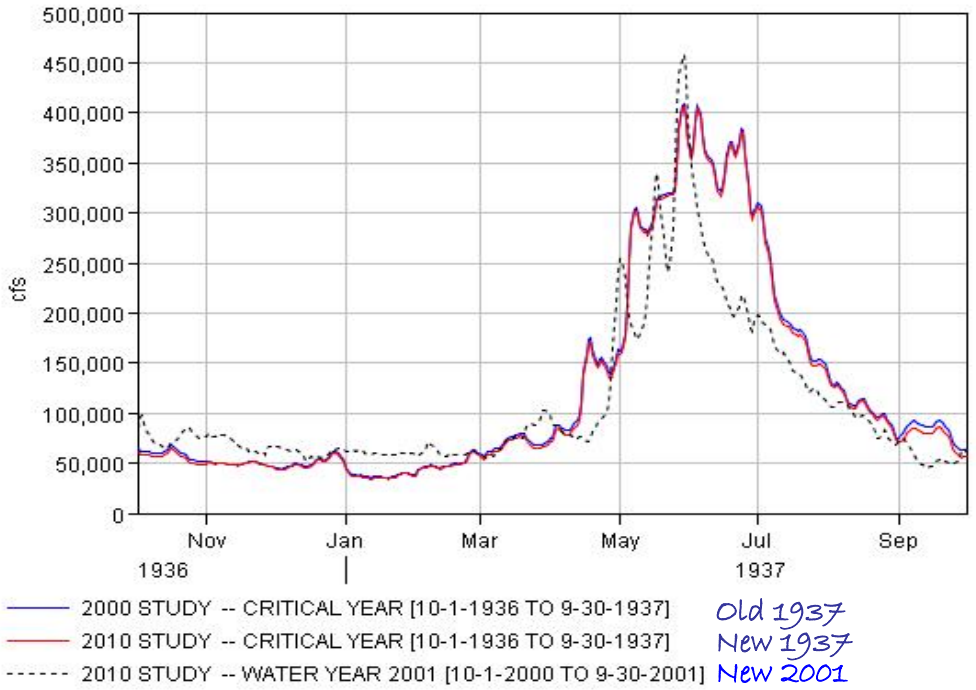
Federal Tier 1 System Firm Critical Output – HYDSIM Study

1 2010 Modified Streamflow Data

- New streamflow data were published in Aug 2011.
- New 2010 data includes 80 years: Oct 1928 - Sep 2008, ten new years plus modified data for the first 70 years.
- New 2010 data includes 2% less water on average compared to the previous 2000 data set.
- Changes are mostly due to more accurate USBR calculation of irrigation withdrawals since 2000.
- New forecast data will also be included in HYDSIM study.

2 Critical Year Not Changing from 1937 to 2001

- Overall, 2001 has 8% less water than 1937. (Volume under dashed line is less than volume under red and blue lines across the whole year.)
- However, the critical period is based on drafting the system from fullest point to lowest point, which generally occurs from late summer thru early spring.
- Fall/Winter flows are 33% higher in 2001 compared to 1937. (Volume under dashed line is greater than volume under red and blue lines across the first half of the year.)
- Spring/Summer flows are 17% lower in 2001, but not enough to offset the fall winter increase and cause a change in the critical year.
- The Northwest Power Pool will run studies later this year for an official PNCA determination of the critical period with the new streamflow data, and we expect 1937 to remain the critical year.



2010 vs 2000 Streamflows during Critical Year (1937)

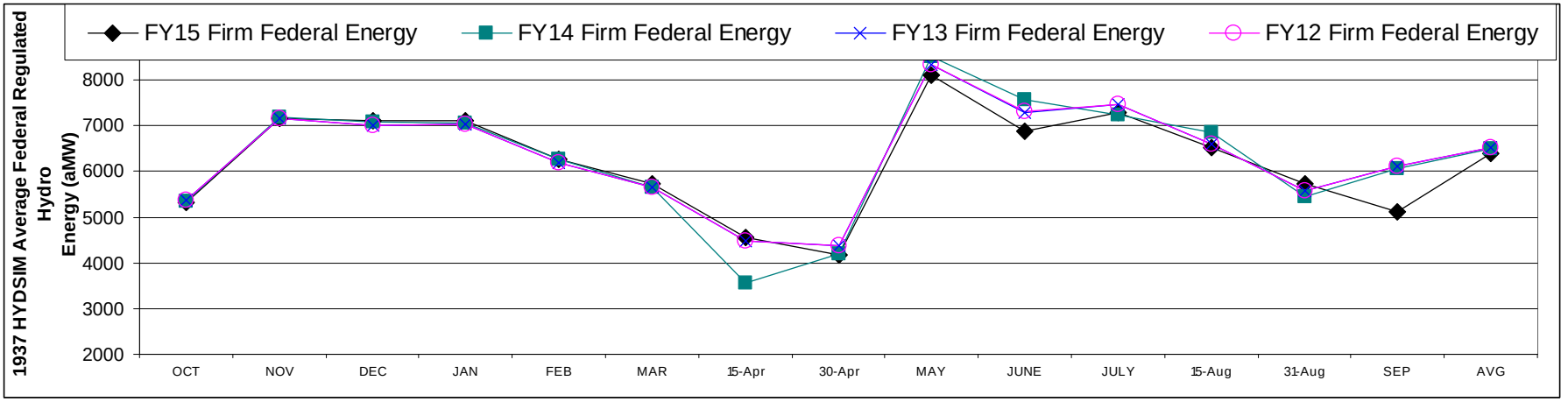
- 1937 has 2% less water in the new streamflow data.
  - In the chart the red line is slightly lower than blue line.
  - 7% less water during the fall and minimal difference throughout rest of year.
  - Most of the difference is in the Snake River Basin.
- This contributes toward reducing the T1SFCO.

Federal Tier 1 System Firm Critical Output – HYDSIM Results

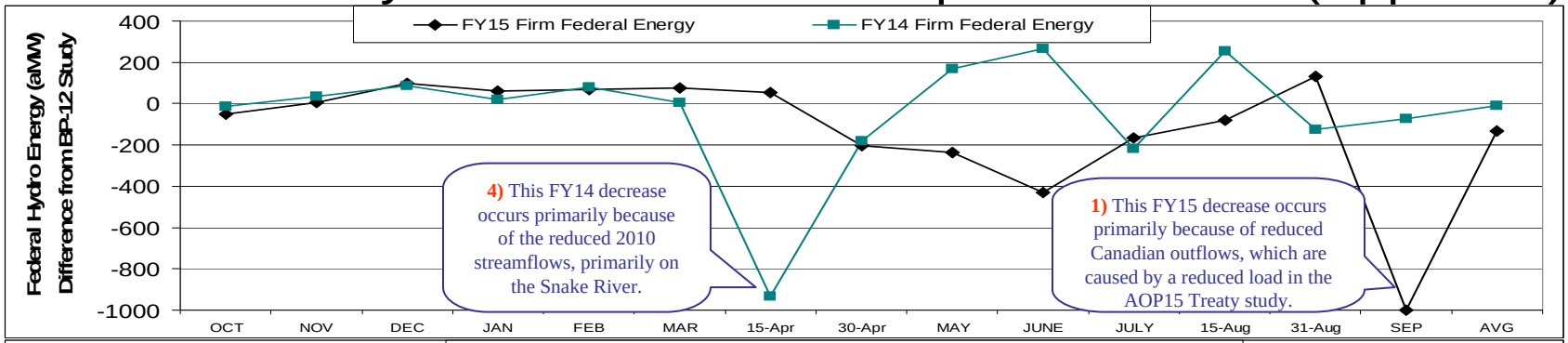
- The new estimate of FY14 & FY15 firm average annual regulated hydro energy is ~73 aMW lower than FY12 & FY13.
- Differences are primarily caused by the 2010-level Modified Streamflows and updated Canadian operations.
- Also, because the two years of studies include different Canadian operations, their annual average generation and monthly shapes differ more than they did in BP-12.

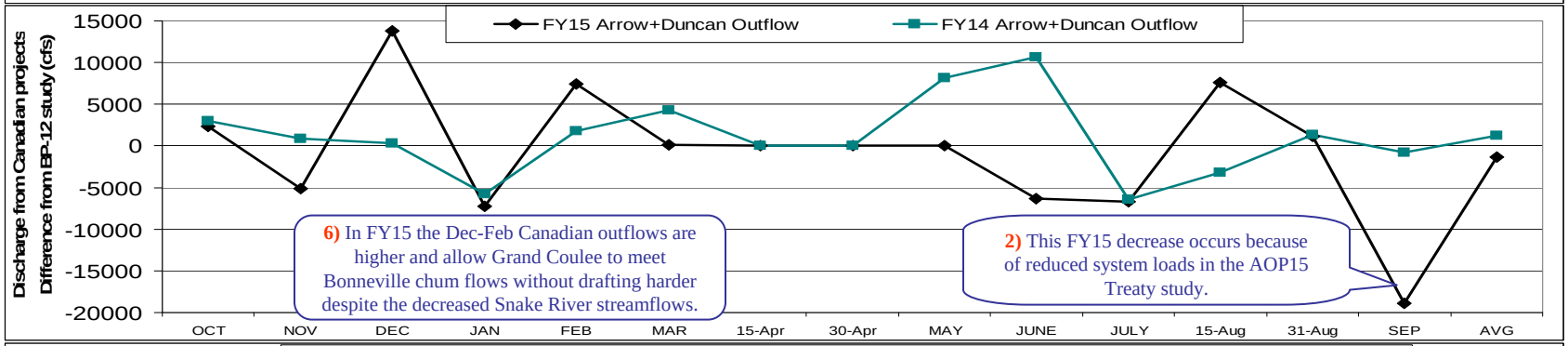
FIRM REGULATED HYDRO ENERGY FROM HYDSIM (aMW)

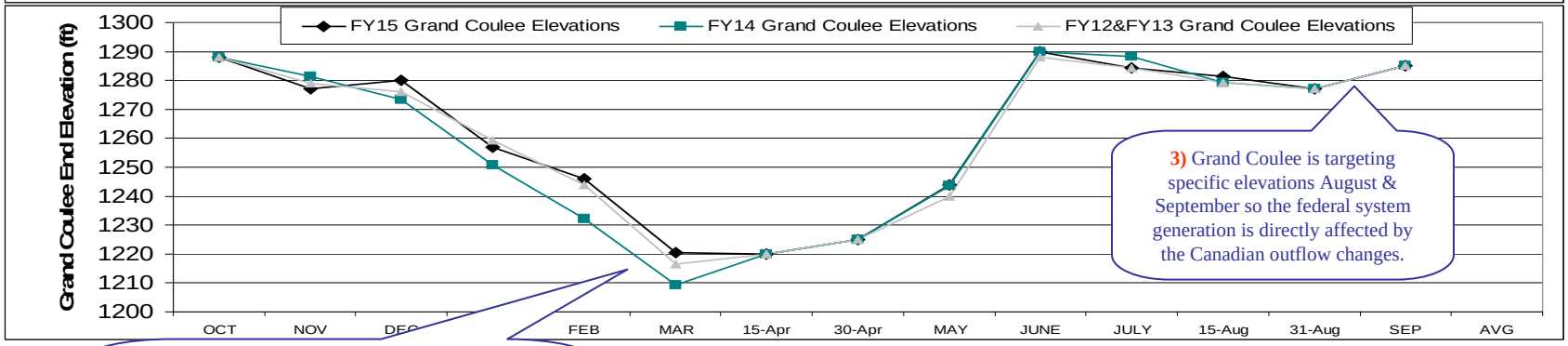
	OCT	NOV	DEC	JAN	FEB	MAR	APR1	APR2	MAY	JUNE	JULY	AUG1	AUG2	SEP	AVG.
FY12	5364	7161	7005	7037	6194	5648	4488	4382	8334	7314	7463	6596	5586	6124	6518
FY13	5364	7161	7005	7037	6194	5648	4488	4382	8331	7287	7463	6596	5586	6124	6516
BP12 FY12&FY13 avg	5364	7161	7005	7037	6194	5648	4488	4382	8333	7301	7463	6596	5586	6124	6517
FY14	5350	7195	7091	7057	6275	5654	3555	4203	8503	7568	7245	6849	5461	6052	6506
FY15	5314	7167	7102	7099	6263	5725	4543	4180	8094	6872	7296	6516	5719	5121	6383
New FY14&FY15 avg	5332	7181	7097	7078	6269	5690	4049	4192	8299	7220	7271	6683	5590	5587	6445
difference from FY12&FY13	-32	20	92	41	75	42	-439	-191	-34	-81	-193	87	4	-538	-73



Federal Tier 1 System Firm Critical Output - HYDSIM (Appendix)







FY 2014-2015 T1SFCO for RHWM
May Customer Workshop

Tier 1 System Firm Critical Output

Next Few Slides

Agenda

- Review T1SFCO Study
  - Explain differences since BP-12
  - Present new annual firm wind methodology
  - Present T1SFCO study results

Today's Discussion

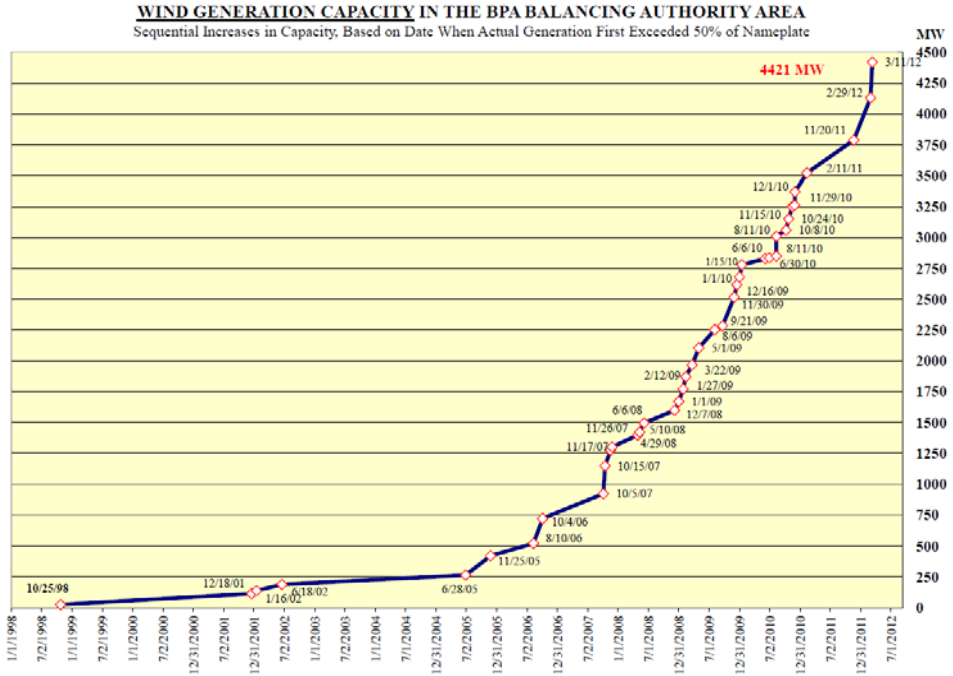
- Provide an overview of forecasting annual firm wind energy:
  - Context
  - Methodology
  - Implications
  - Next steps

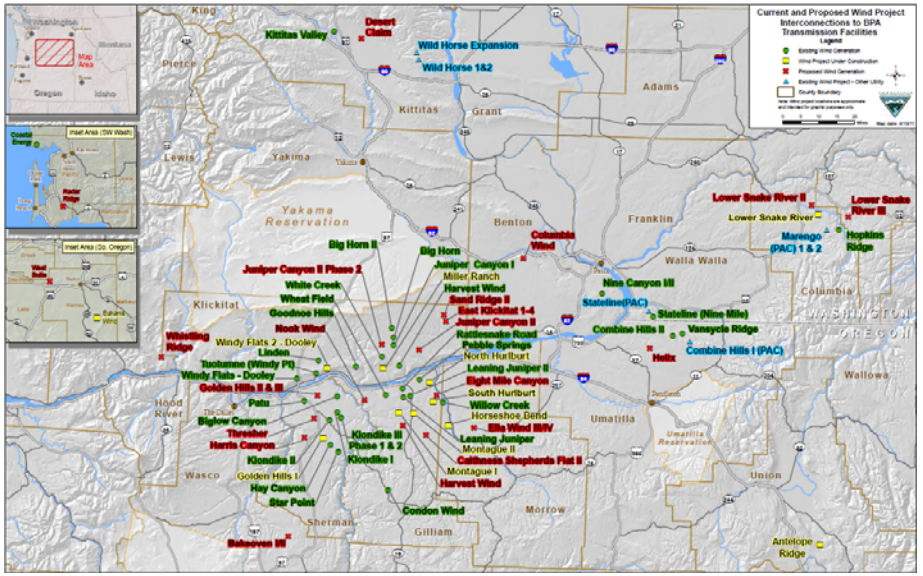
Past & Current Wind Energy Forecasts

- Regional and federal long-term planning studies, such as the White Book, Assured Operating Plan, Wholesale Power Rate Case, and Tier 1 System Firm Critical Output:
  - Originally included wind developers' generation estimates.
  - After sufficient BPA meter data became available, wind developers' estimates were replaced with average historical monthly generation for each wind project.
- Generation estimates in Exhibit A of Regional Dialogue Contracts are based on each wind project's lowest historical Fiscal Year generation, per the 2008 Exhibit A Data Standards.

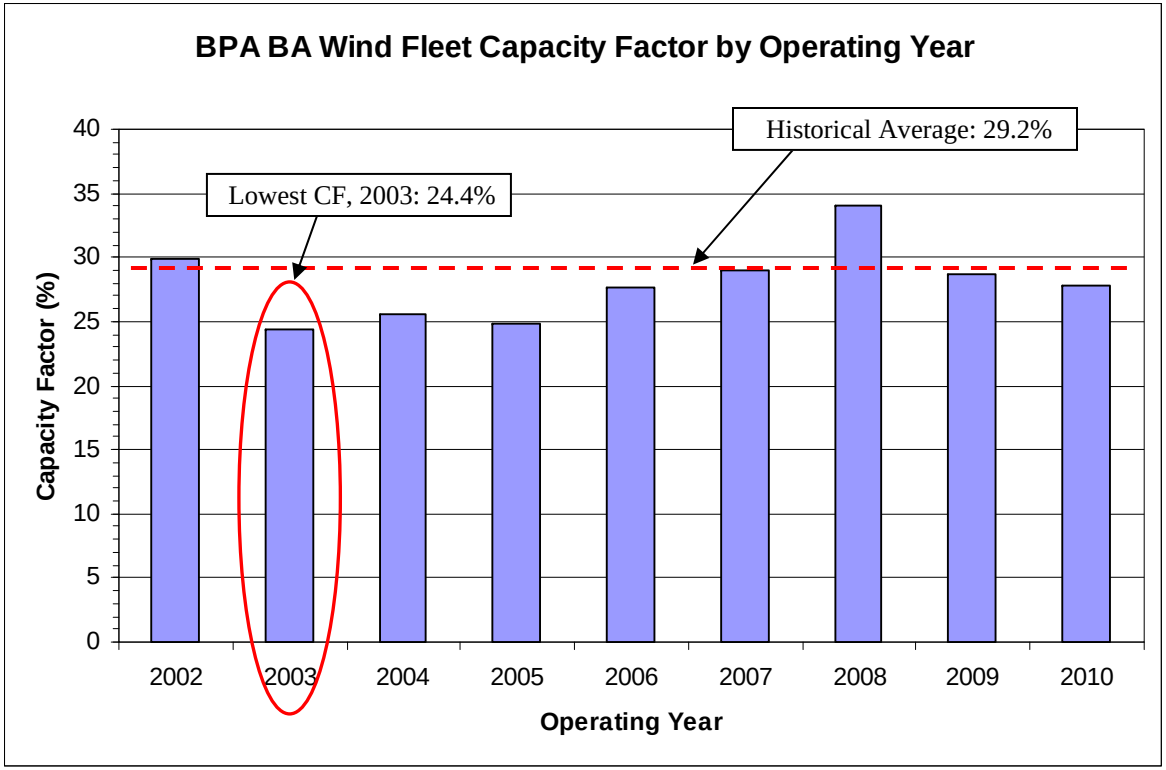
Why estimate annual firm wind energy?

- Growth of installed wind capacity in the region.
- Change in wind fleet performance as additional projects have been developed.
- Other resource forecasts are determined using methodologies that capture the uncertainties inherent in the resource. Using average historical monthly generation for wind does not capture uncertainties inherent in wind nor is it the best estimate of what is reasonable or likely to occur.



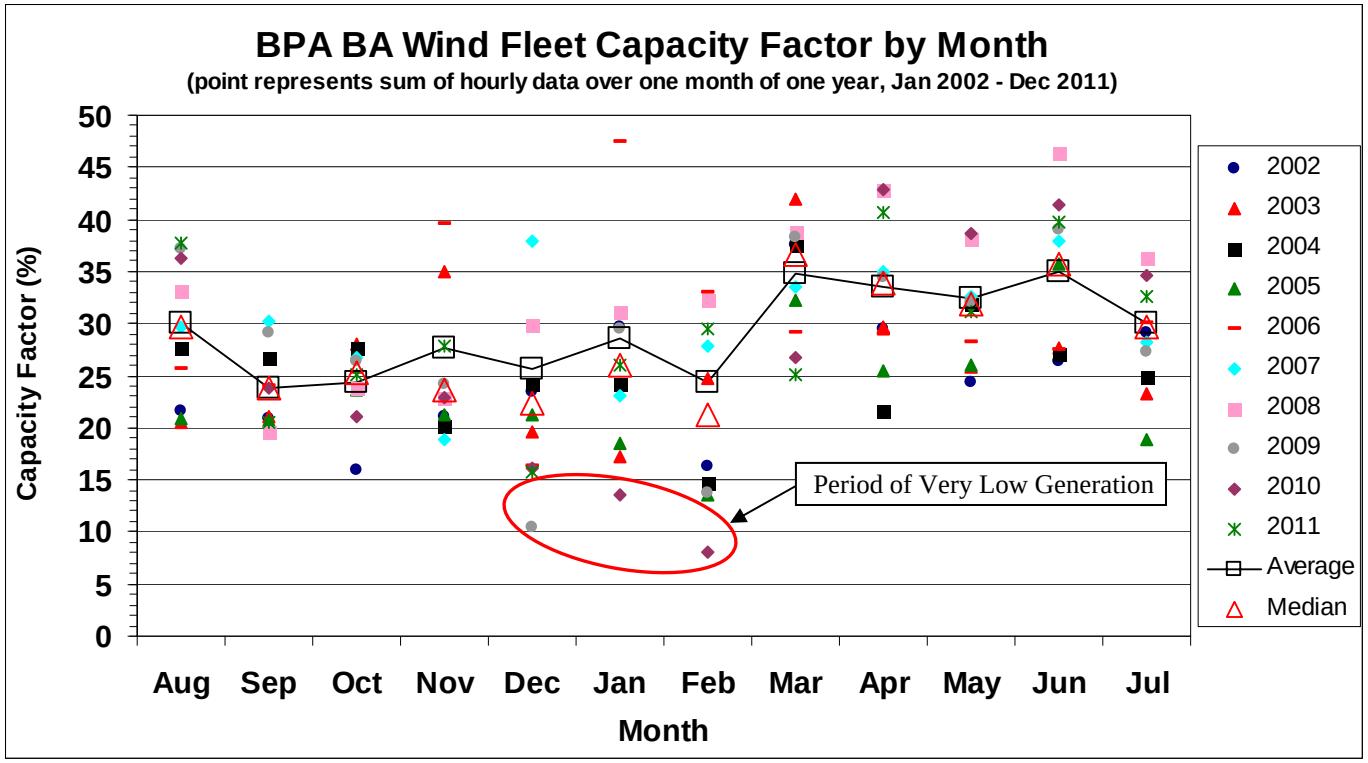


Annual Wind Energy Variability



- Over the historical record (October 1998 – December 2011), the average wind fleet capacity factor was 29.2%
- Over the same time period, the median wind fleet capacity factor was 28.4%
- Thus, there is less than a 50% probability of realizing the current wind energy forecast.

Monthly Wind Energy Variability



- The historical record also shows substantial monthly variability in wind energy.
- The historical record demonstrates that, even with today's wind fleet, very low wind energy may occur in a given month or season (i.e. December 2009 – February 2010).

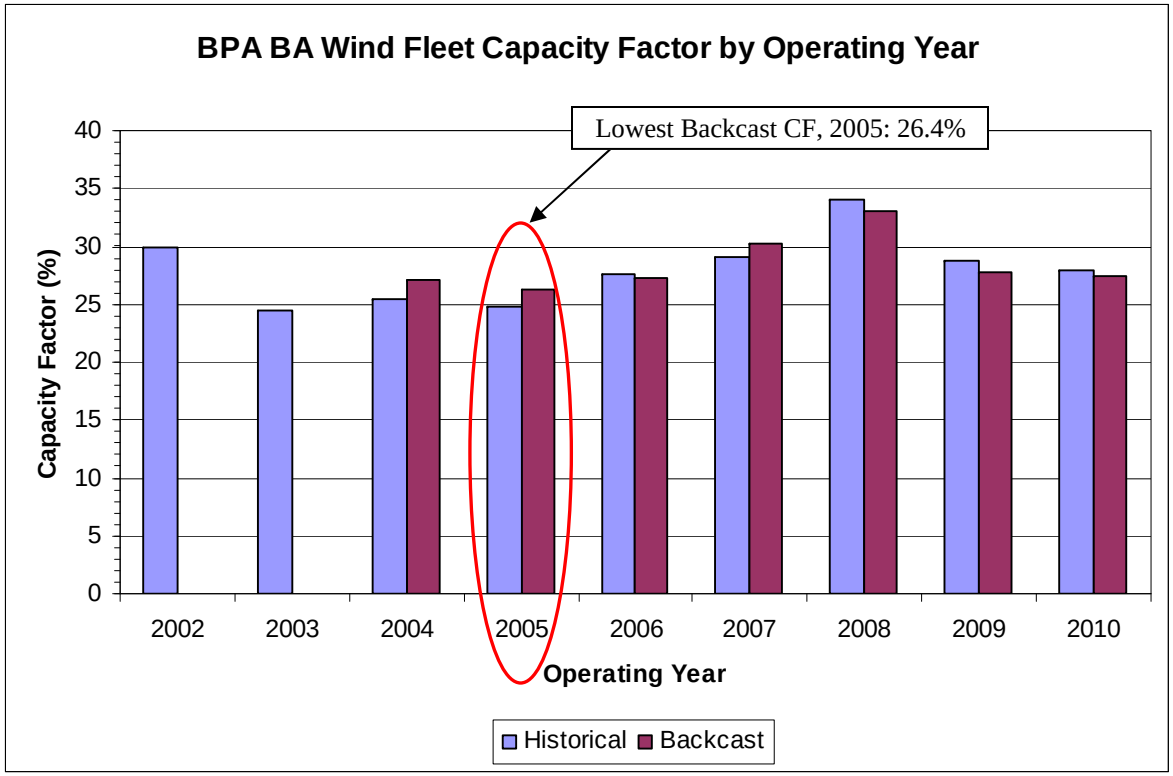
Wind Backcast Model

- Statistical model is developed that predicts hourly wind fleet capacity factors from historical meteorological data (i.e. surface pressure gradients).
- Model is calibrated using the last complete year of data to reflect the performance characteristics of the current (2010) wind fleet.
- Model is applied to historical meteorological data to estimate wind fleet capacity factors.
- Model can be applied only back to November 2002 due to the limited availability of meteorological data for prior years.
- No industry standard for how to evaluate wind energy in long-term planning.

Estimating Annual Firm Wind Energy

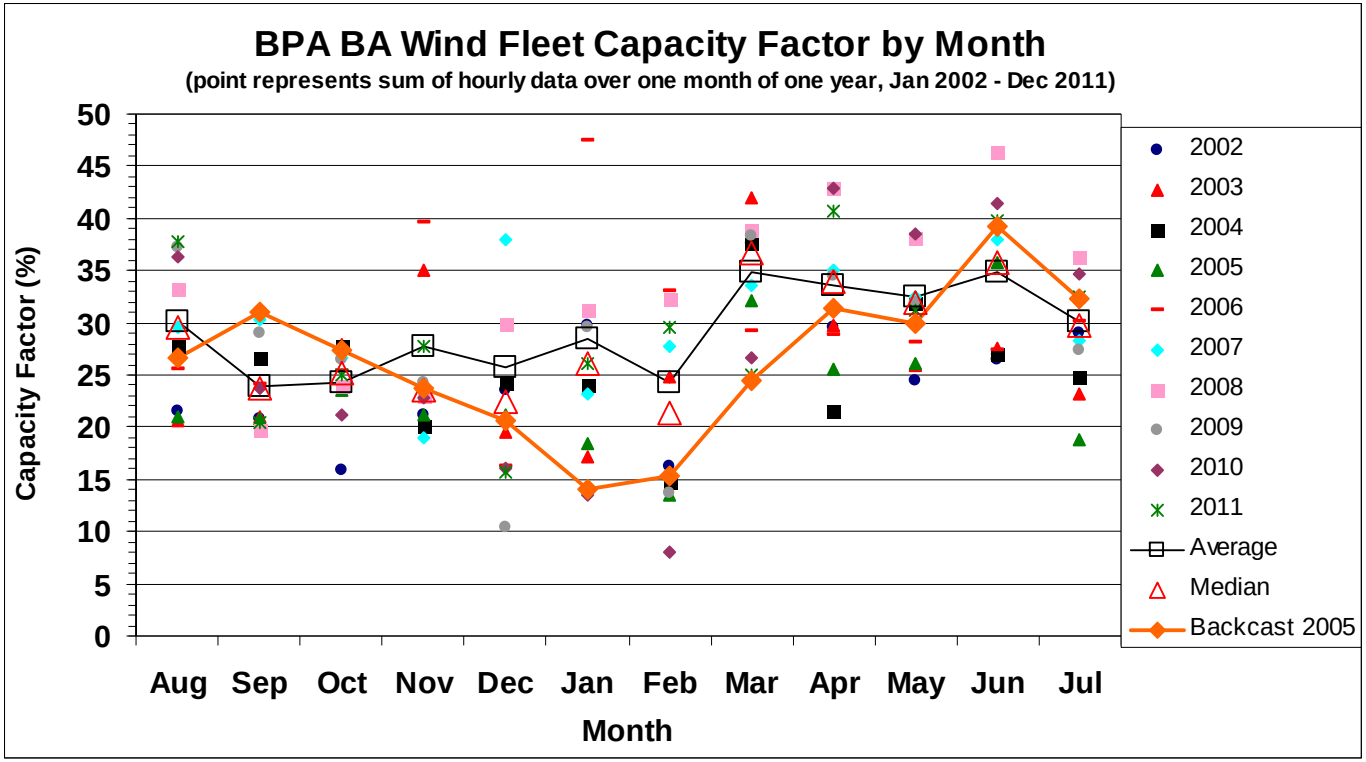
- To estimate annual firm wind energy:
  - For wind projects that have insufficient historical generation data, the lowest backcast model annual generation estimate is used.
  - For all other wind projects, each wind project's historical generation during the year with the lowest backcast model estimate is used.
- There is approximately an 86% probability of realizing annual wind energy greater than the annual firm wind energy estimate in any given year (based on 7 years of backcast model data).
- Annual firm wind energy estimates will be updated annually to reflect current wind fleet performance and incorporate additional wind generation and meteorological data.

Wind Backcast Model Results



- Operating Year 2005 has the lowest annual wind energy estimate of 26.4%.
- Thus, Operating Year 2005 provides the current estimate of annual firm wind energy.

Wind Backcast Model Results, cont.



- Operating Year 2005 includes relatively low wind energy estimates over the winter season.
- Important to capture potential low winter wind energy due to positive correlation with unregulated and regulated water flows and high winter loads.

Annual Firm Wind Energy Impacts

- Canadian Entitlement
  - May reduce the Canadian Entitlement in the 2018 Assured Operating Plan by approximately 3 aMW, equivalent to approximately $1 million.*
  - May reduce the Canadian Entitlement in the 2025 Assured Operating Plan by approximately 9 aMW, equivalent to approximately $3 million.*
- Wholesale Power Rates
  - Reduces the Tier 1 System Firm Critical Output in 2014 and 2015 by approximately 5 aMW.
  - Reduces the firm amount from wind resources used for Rate Period (RP) Augmentation in 2014 and 2015 by approximately 2 aMW.
- Customer Dedicated Resources
  - No impact to existing dedicated wind resources.
  - New wind resource additions will continue to be evaluated using the 2008 Exhibit A Data Standards until project-specific backcast model estimates are available.

* Incorporating annual firm wind energy into the Assured Operating Plan is subject to negotiations. Values reflect rough estimates based on Final Wholesale Power Rate Case 2012 and Operating Year 2013 Mid-C power prices (annual average of $41.31/MWh).

Next Steps

- Begin implementation of the methodology in the following studies:
  - 2012 White Book
  - 2018 Assured Operating Plan
  - 2014 Wholesale Power Rate Case and Tier 1 System Firm Critical Output
- Once project-specific backcast model estimates are available, implement in Exhibit A of Regional Dialogue Contracts for new wind resource additions. In the interim, continue to use methodology described in the 2008 Exhibit A Data Standards.
- Evaluate new annual firm wind energy forecast each year to determine whether it continues to provide a good estimate of firm energy.

FY 2014-2015 T1SFCO for RHWM
May Customer Workshop

Tier 1 System Firm Critical Output

Agenda

- Review T1SFCO Study
  - Explain differences since BP-12
  - ~~Present new annual firm wind methodology~~
  - Present T1SFCO study results

Next Few Slides

Federal Tier 1 System Firm Critical Output

2014-2015 Fiscal Years
RHWM Process - Study 80 (preliminary)

1.	Draft T1SFCO Projections (Study 80) Energy in aMW	2014	2015	Average
2.	Total Federal System Hydro Generation (Table 3.1)	*6,907*	*6,784*	*6,846*
3.	Total Designated Non-Federally Owned Resources (Table 3.2)	*1,098*	*945*	*1,022*
4.	Total Designated BPA Contract Purchases (Table 3.3)	*161*	*156*	*159*
5.	Total Designated System Obligations (Table 3.4)	*(984)*	*(951)*	*(967)*
6.	**Federal Tier 1 System Firm Critical Output**	*7,183*	*6,935*	*7,059*

2012-2013 Fiscal Years
CHWM Process - Study 75

1.	T1SFCO Projections (Study 75) Energy in aMW	2012	2013	Average
2.	Total Federal System Hydro Generation (Table 3.1)	*6,943*	*6,942*	*6,942*
3.	Total Designated Non-Federally Owned Resources (Table 3.2)	*1,103*	*951*	*1,027*
4.	Total Designated BPA Contract Purchases (Table 3.3)	*387*	*385*	*386*
5.	Total Designated System Obligations (Table 3.4)	*(1,231)*	*(1,210)*	*(1,221)*
6.	**Federal Tier 1 System Firm Critical Output**	*7,202*	*7,067*	*7,135*

Federal Tier 1 System Firm Critical Output

T1SFCO Projection Differences (Study 80-Study 75) Energy in aMW	Study 80 (prelim) 2-Year Average	Study 75 2-Year Average	Difference
1. Table 3.1: Total Federal System Hydro Generation	**6,846**	**6,942**	**(97)**
a) Regulated Hydro Generation (HYDSIM & Encroachments)			*(72)*
b) Independent Hydro updates			*(24)*
2. Table 3.2: Total Designated Non-Federally Owned Resources	**1,022**	**1,027**	**(5)**
a) Changed to annual firm wind			*(5)*
3. Table 3.3: Total Designated BPA Contract Purchases	**159**	**386**	**(227)**
a) Removed netted BPA Tx contracts (So. Idaho, Harney and Wells)			*(220)*
b) Expiration of PPL Seasonal Exchange			*(4)*
c) Miscellaneous			*(3)*
4. Table 3.4: Total Designated System Obligations	**(967)**	**(1,221)**	**253**
a) Removed netted BPA Tx contracts (So. Idaho, Harney and Wells)			*220*
b) Canadian Entitlement Return to Canada			*26*
c) Federal Power Tx Losses			*9*
d) Miscellaneous			*(3)*
5. Difference Federal Tier 1 System Firm Critical Output (Lines 1+2+3+4)	**7,059**	**7,135**	**(76)**

Federal Tier 1 System Firm Critical Output

Table 3.1: Federal System Hydro Generation (Prelim 2014 T1SFCO Process - Study 80)
Energy in aMW

1.	Regulated Hydro	2014	2015	Average
2.	Albeni Falls	25.3	25.8	25.5
3.	Bonneville Hydro	408.2	397.9	403.0
4.	Chief Joseph Hydro	1,142.0	1,110.7	1,126.4
5.	Dworshak Hydro	142.7	142.7	142.7
6.	Grand Coulee Hydro	1,951.4	1,904.8	1,928.1
7.	Hungry Horse	83.8	83.8	83.8
8.	Ice Harbor Hydro	154.6	154.6	154.6
9.	John Day Hydro	825.5	810.4	817.9
10.	Libby	182.1	182.1	182.1
11.	Little Goose Hydro	175.8	175.8	175.8
12.	Lower Granite Hydro	168.7	168.9	168.8
13.	Lower Monumental Hydro	179.9	179.9	179.9
14.	McNary Hydro	494.0	484.5	489.3
15.	The Dalles Hydro	619.4	608.5	614.0
16.	**Independent Hydro**			
17.	Anderson Ranch	13.0	13.0	13.0
18.	Big Cliff	9.7	9.7	9.7
19.	Black Canyon	6.2	6.2	6.2
20.	Boise River Diversion	1.1	1.1	1.1
21.	Bonneville Fishway **(Already Included in new Bonneville PNCA plant data)**	*0.0*	*0.0*	*0.0*
22.	Chandler	5.6	5.6	5.6
23.	Cougar	18.8	18.8	18.8
24.	Cowlitz Falls	26.2	26.2	26.2
25.	Detroit	33.3	33.3	33.3
26.	Dexter	9.3	9.3	9.3
27.	Foster	12.2	12.2	12.2
28.	Green Peter	26.9	26.9	26.9
29.	Green Springs - USBR	7.3	7.3	7.3
30.	Hills Creek	17.8	17.8	17.8
31.	Idaho Falls - City Plant	4.1	4.1	4.1
32.	Idaho Falls - Lower Plant 1 & 2	5.7	5.7	5.7
33.	Idaho Falls - Upper Plant	4.1	4.1	4.1
34.	Lookout Point	35.3	35.3	35.3
35.	Lost Creek	30.0	30.0	30.0
36.	Minidoka	11.2	11.2	11.2
37.	Palisades	69.2	69.2	69.2
38.	Roza	6.9	6.9	6.9
39.	***Total Federal System Hydro Generation***	***6,907.2***	***6,784.3***	***6,845.8***

- Independent Hydro estimates are updated based on project owners' data reflecting 2010-level Modified Streamflows.
- Bonneville Fishway generation is included in Bonneville Dam's Regulated Hydro using the updated h/k plant data included in 2012 PNCA data.

Federal Tier 1 System Firm Critical Output

Table 3.2: Designated Non-Federally Owned Resources (Prelim 2014 T1SFCO Process - Study 80)
Energy in aMW

1.	Project	2014	2015	Average
2.	Ashland Solar Project	0.0	0.0	0.0
3.	Columbia Generating Station	1,030.0	877.6	953.8
4.	Condon Wind Project	9.6	9.6	9.6
5.	Dworshak/Clearwater Small Hydropower	2.6	2.6	2.6
6.	Elwha Hydro **(Generation off-line beginning 6/1/2011)**	*0.0*	*0.0*	*0.0*
7.	Foote Creek 1	4.0	4.0	4.0
8.	Foote Creek 2	0.5	0.5	0.5
9.	Foote Creek 4	4.4	4.4	4.4
10.	Fourmile Hill Geothermal **(Not included)**	*0.0*	*0.0*	*0.0*
11.	Georgia-Pacific Paper (Wauna)	19.2	19.2	19.2
12.	Glines Canyon Hydro **(Generation off-line beginning 6/1/2011)**	*0.0*	*0.0*	*0.0*
13.	Klondike I	6.8	6.8	6.8
14.	Stateline Wind Project	20.7	20.7	20.7
15.	White Bluffs Solar	0.0	0.0	0.0
16.	***Total Designated Non-Federally Owned Resources***	***1,097.9***	***945.5***	***1,021.7***

- Highlighted rows reflect changes since the BP-12 study.

Federal Tier 1 System Firm Critical Output

Table 3.3: Designated BPA Contract Purchases (Draft 2014 T1SFCO Process - Study 80)
Energy in aMW

1.	Contract Purchases	Contract #	2014	2015	Average
2.	Priest Rapids CER for Canada	97PB-10099	29.1	29.2	29.2
3.	Rock Island #1 CER for Canada	97PB-10102	11.0	11.0	11.0
4.	Rock Island #2 CER for Canada	97PB-10102	7.0	7.0	7.0
5.	Rock Reach CER for Canada	97PB-10103	37.3	37.4	37.4
6.	Wanapum CER for Canada	97PB-10100	28.2	28.2	28.2
7.	Wells CER for Canada	97PB-10101	23.9	23.9	23.9
8.	BCHP to BPA PwrS	99PB-22685	1.0	1.0	1.0
9.	PASA to BPA Pk Repl	DE-MS79-94BP93658	1.1	0.0	0.6
10.	PASA to BPA S/N/X	DE-MS79-94BP93658	0.4	0.3	0.3
11.	PASA to BPA Xchg Nrg	DE-MS79-94BP93658	1.9	1.6	1.7
12.	PPL to BPA So Idaho **(netted 0 with Table 3.4 line 26)**	89BP-92524	*0.0*	*0.0*	*0.0*
13.	RVSD to BPA Pk Repl	94BP-93958	4.9	5.0	5.0
14.	RVSD to BPA Seas Xchg	94BP-93958	4.3	4.3	4.3
15.	RVSD to BPA Xchg Nrg	94BP-93958	7.3	7.3	7.3
16.	SPP to BPA Harney Wells **(netted 0 with Table 3.4 line 21)**	88BP-92436	*0.0*	*0.0*	*0.0*
17.	PPL to BPA SNX (Spring Return)	DE-MS79-94BP94332	0.0	0.0	0.0
18.	PPL to BPA SPX (Summer Return)	DE-MS79-94BP94332	3.8	0.0	1.9
19.	***Total Designated BPA Contract Purchases***		***161.3***	***156.3***	***158.8***

- Lines 12 & 16 were updated to reflect the zeroing out of transmission pass-through contracts that netted to zero and are no longer going to be reflected in the studies. In Study 75 these contracts were included (~220 aMW) but were offset by obligations (also ~220 aMW) in Table 3.4 lines 21 & 26 such that the purchases and obligations for transmission pass-through netted to zero. Because they netted to zero in the previous study's T1SFCO, this change does not affect the overall Federal T1SFCO.

Federal Tier 1 System Firm Critical Output

Table 3.4: Designated BPA System Obligations (Draft 2014 T1SFCO Process - Study 80)
Energy in aMW

1.	System Obligations	Contract #	2014	2015	Average
2.	BPA to BRCB Columbia Basin Project	Ibp-4512; 14-03-001-12160	135.5	135.5	135.5
3.	BPA to BRCJ Chief Joseph	14-03-17506; 14-03-49151	8.2	8.2	8.2
4.	BPA to BRCR Crooked River Project	14-03-73152	1.1	1.1	1.1
5.	BPA to BROP Owyhee Project	EW-78-Y-83-00019	3.4	3.4	3.4
6.	BPA to BRRP Rathdrum Prairie Project	14-03-49151	0.7	0.7	0.7
7.	BPA to BRSID Southern Idaho Projects	EW-78-Y-83-00019	19.6	19.6	19.6
8.	BPA to BRSIN Spokane Indian Development	14-03-49151	0.3	0.3	0.3
9.	BPA to BRSV Spokane Valley	14-03-63656	0.7	0.7	0.7
10.	BPA to BRTD The Dalles Reclamation Project	14-03-32210	2.0	2.0	2.0
11.	BPA to BRTV Tualatin Project	14-03-49151	0.6	0.6	0.6
12.	BPA to BRUB Umatilla Basin Project	10GS-75345	0.0	0.0	0.0
13.	BPA to BRYK Yakima Project	DE-MS79-88BP9259	1.7	1.7	1.7
14.	BPA To BCHA Can Ent	99EO-40003	499.6	474.6	487.1
15.	BPA to BHEC 2012PSC	97PB-10051	5.2	5.2	5.2
16.	BPA to PASA C/N/X	94BP-93658	1.1	0.0	0.6
17.	BPA to PASA S/N/X	94BP-93658	0.4	0.0	0.2
18.	BPA to RVSD C/N/X	94BP-93958	4.9	5.0	5.0
19.	BPA to RVSD Seas Xchg	94BP-93958	4.3	4.3	4.3
20.	Federal Intertie Losses **(Calculated: 3.0% of Intertie Sales in Table 3.4 lines 16-19)**	*-Calculated-*	0.3	0.3	0.3
21.	BPA to SPP Pwr S **(netted 0 with Table 3.3 line16)**	88BP-92436	*0.0*	*0.0*	*0.0*
22.	BPA to AVWP WP3 S	85BP-92186	45.3	45.6	45.5
23.	BPA to PPL SNX (Spring Delivery)	94BP-94332	0.0	0.0	0.0
24.	BPA to PPL SPX (Summer Delivery)	94BP-94332	0.0	0.0	0.0
25.	BPA to PSE Pwr S (Up. Baker 2)	09PB-12126	0.8	0.8	0.8
26.	BPA to PPL SoID **(netted 0 with Table 3.3 line 12)**	89BP-92524	*0.0*	*0.0*	*0.0*
27.	BPA to PSE WP3 S	85BP-92185	45.3	45.6	45.5
28.	BPAP to BPAT **(Ditmer/Substation Service)**	09PB-12128	9.1	9.1	9.1
29.	Federal Power Trans. Losses **(Calculated: 2.82% of totals in Tables 3.1, 3.2, & 3.3)**	*-Calculated-*	230.3	222.4	226.3
30.	Transmission Returns (Slice) **(27.027%*1.9%* sum of Tables 3.1, 3.2, & 3.3 less sum of Table 3.4 lines 1-29)**	*-Calculated-*	-36.7	-35.4	-36.1
31.	***Total Designated System Obligations***		***983.7***	***951.2***	***967.4***

- Lines 21 & 26 were updated to reflect the zeroing out of transmission pass-through obligations that netted to zero and are no longer going to be reflected in the studies. In Study 75 these obligations were included (~220 aMW) but were offset by contracts (also ~220 aMW) in Table 3.3 lines 12 & 16 such that the purchases and obligations for transmission pass-through netted to zero. Because they netted to zero in the previous study's T1SFCO, this change does not affect the overall Federal T1SFCO.

Calculation Examples

- Please refer to separate handout.