Attachments to

ADMINISTRATOR'S DRAFT EQUIVALENT BENEFITS ANALYSIS DETERMINATION TO EXTEND CONTRACT NO. 10PB-12175 WITH ALCOA (INITIAL PERIOD EXTENSION REQUEST)

October 6, 2010

BONNEVILLE
POWER ADMINISTRATION

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Attachment A

Letter from Alcoa Requesting Extension Consistent with EBT

ALCOA

Alcoa Primary Metals
Intalco Works
4050 Mountain View Road
P.O. Box 937
Ferndale, WA 98248 USA
Tel: 1 360 384 7061
Fax:1 360 384 6185

September 2, 2010

Via e-mail and U.S. Mail

Mark E. Miller
Account Executive
Bonneville Power Administration
905 NE 11th Avenue
PO Box 3621
Portland, OR 97208-3621

Re: Contract No. 10 PB-12175 - Request for Extension of Initial Period

Dear Mark:

Pursuant to Sections 5.1.1 and 17.5 of the above referenced Power Sales Agreement ("Agreement") between Bonneville Power Administration and Alcoa Inc. ("Alcoa"), this letter is to request that BPA extend the Initial Period under the Agreement for such period (not exceeding one year) as BPA may determine that it will receive Equivalent Benefits from Firm Power Sales to Alcoa under the Agreement for the 320 aMW presently being purchased under the Agreement. To permit Alcoa to make operating and employment decisions on a timely basis, we request that BPA make its determination within 30 days, or by October 2, 2010.

By making this request, Alcoa does not concede that the Equivalent Benefits Test ("EBT") is appropriate or lawful. However, delays in the briefing schedule in *Alcoa v. BPA*, 9th Circuit case No. 10-70211, make it extremely unlikely that the Court will rule on the lawfulness of the EBT prior to the time that Alcoa would have to make a shutdown decision affecting the Intalco Works smelter. Therefore, in order to permit the smelter to operate while the Court deliberates, we hereby request an Extended Initial Period as contemplated under the Agreement that is presently being reviewed by the Court.

Please contact me if you have any questions concerning this request.

Sincerely,

Mike Rousseau

Mike Rousseau
Plant Manager

Attachment B

Equivalent Benefits Test Tables – Cumulative Contract-to-September 30th

TABLE 1 - Usage and Rates

Month	Alcoa Ferndale Usage			Projected IP Rates		
	Demand (kW)	HLH (MWh)	LLH (MWh)	Demand ($ / kW)	HLH ($ / MWh)	LLH ($ / MWh)
Dec-09	285,000	36,480	31,920	$2.30	$35.24	$31.13
Jan-10	300,000	120,000	103,200	$1.96	$38.46	$32.24
Feb-10	315,000	120,960	90,720	$1.99	$37.72	$31.73
Mar-10	320,000	138,240	99,520	$1.85	$35.94	$30.08
Apr-10	320,000	133,120	97,280	$1.74	$32.23	$26.95
May-10	320,000	128,000	110,080	$1.44	$31.69	$22.29
Jun-10	320,000	133,120	97,280	$1.32	$31.18	$23.29
Jul-10	320,000	133,120	104,960	$1.61	$33.33	$28.66
Aug-10	320,000	133,120	104,960	$1.89	$37.31	$31.40
Sep-10	320,000	128,000	102,400	$1.96	$36.49	$32.26

TABLE 2 - BPA's Projected Revenue

Month	Revenues by Rate Determinant			Projected IP Revenue	
	Demand ($)	HLH ($)	LLH ($)	Month ($)	Cumulative Total Contract-to-Date ($)
Dec-09	$211,452	$1,285,555	$993,670	$2,490,676	$2,490,676
Jan-10	$588,000	$4,615,200	$3,327,168	$8,530,368	$11,021,044
Feb-10	$626,850	$4,562,611	$2,878,546	$8,068,007	$19,089,051
Mar-10	$592,000	$4,968,346	$2,993,562	$8,553,907	$27,642,958
Apr-10	$556,800	$4,290,458	$2,621,696	$7,468,954	$35,111,912
May-10	$460,800	$4,056,320	$2,453,683	$6,970,803	$42,082,715
Jun-10	$422,400	$4,150,682	$2,265,651	$6,838,733	$48,921,448
Jul-10	$515,200	$4,436,890	$3,008,154	$7,960,243	$56,881,691
Aug-10	$604,800	$4,966,707	$3,295,744	$8,867,251	$65,748,942
Sep-10	$627,200	$4,670,720	$3,303,424	$8,601,344	$74,350,286
Cumulative for the Period (December 22, 2009 through September 30, 2010)				$74,350,286	

TABLE 3 - BPA's Forecasted Revenues Obtained from the Market

Month	Forecasted Market HLH Price ($ / MWh)	Forecasted Market LLH Price ($ / MWh)	Forecasted Revenues Obtained from the Market HLH ($)	LLH ($)	Month ($) (HLH + LLH)	Cumulative Total Contract-to-Date ($)
Dec-09	$51.48	$42.40	$1,878,136	$1,353,408	$3,231,544	$3,231,544
Jan-10	$46.65	$40.36	$5,597,884	$4,164,786	$9,762,670	$12,994,214
Feb-10	$44.54	$39.66	$5,387,731	$3,597,599	$8,985,330	$21,979,544
Mar-10	$39.94	$33.42	$5,521,395	$3,326,151	$8,847,546	$30,827,090
Apr-10	$38.40	$31.00	$5,111,719	$3,015,421	$8,127,140	$38,954,230
May-10	$29.70	$24.69	$3,801,972	$2,717,591	$6,519,563	$45,473,792
Jun-10	$15.83	$2.91	$2,107,378	$283,441	$2,390,820	$47,864,612
Jul-10	$35.37	$21.77	$4,708,111	$2,285,216	$6,993,327	$54,857,939
Aug-10	$39.35	$27.17	$5,238,573	$2,852,068	$8,090,641	$62,948,580
Sep-10	$36.28	$26.77	$4,643,752	$2,741,636	$7,385,388	$70,333,968
Cumulative for the Period (December 22, 2009 through September 30, 2010)					$70,333,968	

TABLE 4 - BPA's Net Benefit before Adjustment

Month	Net Revenue or (Cost) Month ($)	Cumulative Total Contract-to-Date ($)
Dec-09	($740,868)	($740,868)
Jan-10	($1,232,302)	($1,973,170)
Feb-10	($917,323)	($2,890,493)
Mar-10	($293,639)	($3,184,131)
Apr-10	($658,186)	($3,842,318)
May-10	$451,240	($3,391,077)
Jun-10	$4,447,913	$1,056,836
Jul-10	$966,916	$2,023,752
Aug-10	$776,611	$2,800,363
Sep-10	$1,215,956	$4,016,318
Cumulative for the Period (December 22, 2009 through September 30, 2010)	$4,016,318	

TABLE 5a - BPA's Net Benefit Adjustments

Value of Reserves

Month	Month ($)	Cumulative Total Contract-to-Date ($)
Dec-09	$54,720	$54,720
Jan-10	$178,560	$233,280
Feb-10	$169,344	$402,624
Mar-10	$190,208	$592,832
Apr-10	$184,320	$777,152
May-10	$190,464	$967,616
Jun-10	$184,320	$1,151,936
Jul-10	$190,464	$1,342,400
Aug-10	$190,464	$1,532,864
Sep-10	$184,320	$1,717,184
Cumulative for the Period	$1,717,184	

(December 22, 2009 through September 30, 2010)

TABLE 5b - BPA's Net Benefit Adjustments

Avoided Tx and Ancillary Service Costs

Month	Month ($)	Proportional Month ($)	Cumulative Total Contract-to-Date ($)
Dec-09	$0	$0	$0
Jan-10	$26,500	$23,382	$23,382
Feb-10	$10,305	$9,548	$32,930
Mar-10	$8,833	$8,314	$41,243
Apr-10	$17,666	$16,627	$57,870
May-10	$680,462	$640,435	$698,306
Jun-10	$658,512	$619,776	$1,318,082
Jul-10	$365,840	$344,320	$1,662,402
Aug-10	$148,692	$139,946	$1,802,347
Sep-10	$11,778	$11,085	$1,813,432
Cumulative for the Period		$1,813,432	

(December 22, 2009 through September 30, 2010)

TABLE 5c - BPA's Net Benefit Adjustments

Demand Shift

Month	Month ($)	Proportional Adjusted Month ($)	Cumulative Total Contract-to-Date ($)
Dec-09	$0	$0	$0
Jan-10	$0	$0	$0
Feb-10	$0	$0	$0
Mar-10	$0	$0	$0
Apr-10	$0	$0	$0
May-10	$0	$0	$0
Jun-10	$0	$0	$0
Jul-10	$0	$0	$0
Aug-10	$0	$0	$0
Sep-10	$0	$0	$0
Cumulative for the Period (December 22, 2009 through September 30, 2010)		$0	

TABLE 6 - BPA's Net Benefit after Adjustments

BPA's Adjusted Net Revenue or (Cost)

Month	Net Revenue or (Cost) (A) Month ($)	Value of Reserves (B) Month ($)	Avoided Tx Costs (C) Month ($)	Demand Shift (D) Month ($)	A + B + C + D Month ($)	Cumulative Total Contract-to-Date ($)
Dec-09	($740,868)	$54,720	$0	$0	($686,148)	($686,148)
Jan-10	($1,232,302)	$178,560	$23,382	$0	($1,030,360)	($1,716,508)
Feb-10	($917,323)	$169,344	$9,548	$0	($738,432)	($2,454,939)
Mar-10	($293,639)	$190,208	$8,314	$0	($95,117)	($2,550,056)
Apr-10	($658,186)	$184,320	$16,627	$0	($457,239)	($3,007,295)
May-10	$451,240	$190,464	$640,435	$0	$1,282,140	($1,725,156)
Jun-10	$4,447,913	$184,320	$619,776	$0	$5,252,009	$3,526,853
Jul-10	$966,916	$190,464	$344,320	$0	$1,501,700	$5,028,554
Aug-10	$776,611	$190,464	$139,946	$0	$1,107,020	$6,135,574
Sep-10	$1,215,956	$184,320	$11,085	$0	$1,411,361	$7,546,935
Cumulative for the Period (December 22, 2009 through September 30, 2010)					$7,546,935	

Attachment C

Equivalent Benefits Test Tables – Cumulative Initial Period (Dec 22, 2009 through May 26, 2011)

TABLE 1 - Usage and Rates

Month	Alcoa Ferndale Usage			Projected IP Rates		
	Demand (kW)	HLH (MWh)	LLH (MWh)	Demand ($ / kW)	HLH ($ / MWh)	LLH ($ / MWh)
Oct-10	320,000	133,120	104,960	$2.05	$31.92	$27.01
Nov-10	320,000	128,000	102,720	$2.19	$33.33	$29.58
Dec-10	320,000	133,120	104,960	$2.30	$35.24	$31.13
Jan-11	320,000	128,000	110,080	$1.96	$38.46	$32.24
Feb-11	320,000	122,880	92,160	$1.99	$37.72	$31.73
Mar-11	320,000	138,240	99,520	$1.85	$35.94	$30.08
Apr-11	320,000	133,120	97,280	$1.74	$32.23	$26.95
May-11	320,000	107,520	92,160	$1.44	$31.69	$22.29

TABLE 2 - BPA's Projected Revenue

Month	Revenues by Rate Determinant			Projected IP Revenue	
	Demand ($)	HLH ($)	LLH ($)	Month ($)	Cumulative Total Contract-to-Date ($)
Oct-10	$656,000	$4,249,190	$2,834,970	$7,740,160	$82,090,446
Nov-10	$700,800	$4,266,240	$3,038,458	$8,005,498	$90,095,944
Dec-10	$736,000	$4,691,149	$3,267,405	$8,694,554	$98,790,498
Jan-11	$627,200	$4,922,880	$3,548,979	$9,099,059	$107,889,557
Feb-11	$636,800	$4,635,034	$2,924,237	$8,196,070	$116,085,627
Mar-11	$592,000	$4,968,346	$2,993,562	$8,553,907	$124,639,534
Apr-11	$556,800	$4,290,458	$2,621,696	$7,468,954	$132,108,488
May-11	$386,477	$3,407,309	$2,054,246	$5,848,033	$137,956,521
Cumulative for the Period (October 1, 2010 through May 26, 2011)				$63,606,234	

TABLE 3 - BPA's Forecasted Revenues Obtained from the Market

Month	Forecasted Market		Forecasted Revenues Obtained from the Market			
	HLH Price ($ / MWh)	LLH Price ($ / MWh)	HLH ($)	LLH ($)	Month ($) (HLH + LLH)	Cumulative Total Contract-to-Date ($)
Oct-10	$35.22	$26.86	$4,688,907	$2,819,709	$7,508,615	$77,842,583
Nov-10	$40.18	$31.03	$5,143,671	$3,187,784	$8,331,455	$86,174,039
Dec-10	$43.04	$33.68	$5,729,934	$3,534,763	$9,264,697	$95,438,736
Jan-11	$40.72	$31.38	$5,212,489	$3,454,488	$8,666,977	$104,105,713
Feb-11	$41.95	$32.67	$5,154,286	$3,011,137	$8,165,423	$112,271,137
Mar-11	$39.90	$29.92	$5,515,448	$2,977,576	$8,493,024	$120,764,160
Apr-11	$36.06	$26.78	$4,800,395	$2,604,710	$7,405,105	$128,169,266
May-11	$33.34	$20.39	$3,584,806	$1,878,927	$5,463,733	$133,632,999
Cumulative for the Period (October 1, 2010 through May 26, 2011)					$63,299,031	

TABLE 4 - BPA's Net Benefit before Adjustment

Month	Net Revenue or (Cost) Month ($)	Net Revenue or (Cost) Cumulative Total Contract-to-Date ($)
Oct-10	$231,545	$4,247,863
Nov-10	($325,958)	$3,921,905
Dec-10	($570,144)	$3,351,762
Jan-11	$432,082	$3,783,844
Feb-11	$30,647	$3,814,491
Mar-11	$60,884	$3,875,374
Apr-11	$63,848	$3,939,222
May-11	$384,299	$4,323,522
Cumulative for the Period (October 1, 2010 through May 26, 2011)	$307,203	

TABLE 5a - BPA's Net Benefit Adjustments

Month	Value of Reserves Month ($)	Value of Reserves Cumulative Total Contract-to-Date ($)
Oct-10	$190,464	$1,907,648
Nov-10	$184,576	$2,092,224
Dec-10	$190,464	$2,282,688
Jan-11	$190,464	$2,473,152
Feb-11	$172,032	$2,645,184
Mar-11	$190,208	$2,835,392
Apr-11	$184,320	$3,019,712
May-11	$159,744	$3,179,456
Cumulative for the Period (October 1, 2010 through May 26, 2011)	$1,462,272	

TABLE 5b - BPA's Net Benefit Adjustments

Avoided Tx and Ancillary Service Costs

Month	Month ($)	Proportional Month ($)	Cumulative Total Contract-to-Date ($)
Oct-10	$8,986	$8,458	$1,821,890
Nov-10	$24,941	$23,474	$1,845,364
Dec-10	$78,517	$73,899	$1,919,262
Jan-11	$371,637	$349,776	$2,269,039
Feb-11	$369,606	$347,865	$2,616,903
Mar-11	$422,785	$397,915	$3,014,818
Apr-11	$374,722	$352,679	$3,367,498
May-11	$478,690	$450,532	$3,818,030
Cumulative for the Period (October 1, 2010 through May 26, 2011)		$2,004,598	

TABLE 5c - BPA's Net Benefit Adjustments

Demand Shift

Month	Month ($)	Proportional Adjusted Month ($)	Cumulative Total Contract-to-Date ($)
Oct-10	($72,700)	($68,423)	($68,423)
Nov-10	$68,857	$64,806	($3,617)
Dec-10	$7,935	$7,468	$3,851
Jan-11	$177,252	$166,825	$170,676
Feb-11	$198,399	$186,729	$357,405
Mar-11	$470,401	$442,730	$800,135
Apr-11	$178,253	$167,768	$967,903
May-11	$637,056	$599,582	$1,567,485
Cumulative for the Period (October 1, 2010 through May 26, 2011)		$1,567,485	

TABLE 6 - BPA's Net Benefit after Adjustments

BPA's Adjusted Net Revenue or (Cost)

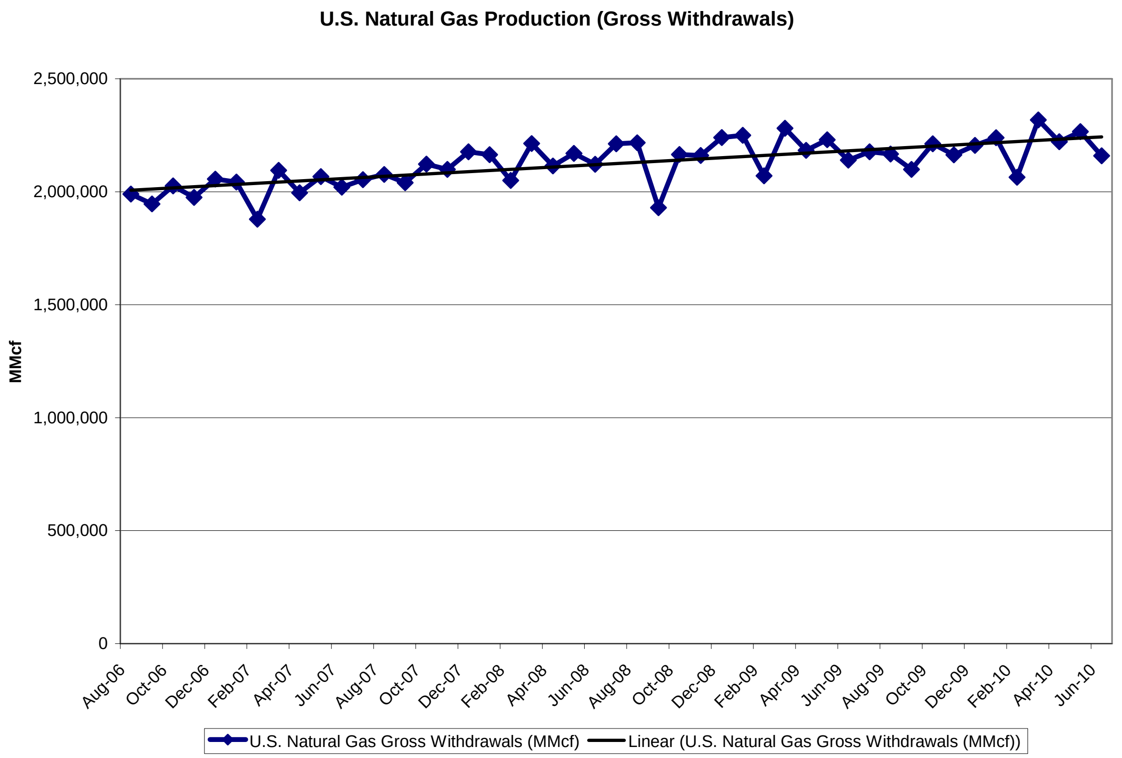
Month	Net Revenue or (Cost) (A) Month ($)	Value of Reserves (B) Month ($)	Avoided Tx Costs (C) Month ($)	Demand Shift (D) Month ($)	A + B + C + D Month ($)	Cumulative Total Contract-to-Date ($)
Oct-10	$231,545	$190,464	$8,458	($68,423)	$362,043	$7,908,978
Nov-10	($325,958)	$184,576	$23,474	$64,806	($53,102)	$7,855,876
Dec-10	($570,144)	$190,464	$73,899	$7,468	($298,313)	$7,557,563
Jan-11	$432,082	$190,464	$349,776	$166,825	$1,139,147	$8,696,710
Feb-11	$30,647	$172,032	$347,865	$186,729	$737,272	$9,433,983
Mar-11	$60,884	$190,208	$397,915	$442,730	$1,091,737	$10,525,720
Apr-11	$63,848	$184,320	$352,679	$167,768	$768,615	$11,294,335
May-11	$384,299	$159,744	$450,532	$599,582	$1,594,157	$12,888,492
Cumulative for the Period (October 1, 2010 through May 26, 2011)					$5,341,558	

Attachment D

Natural Gas Statistics

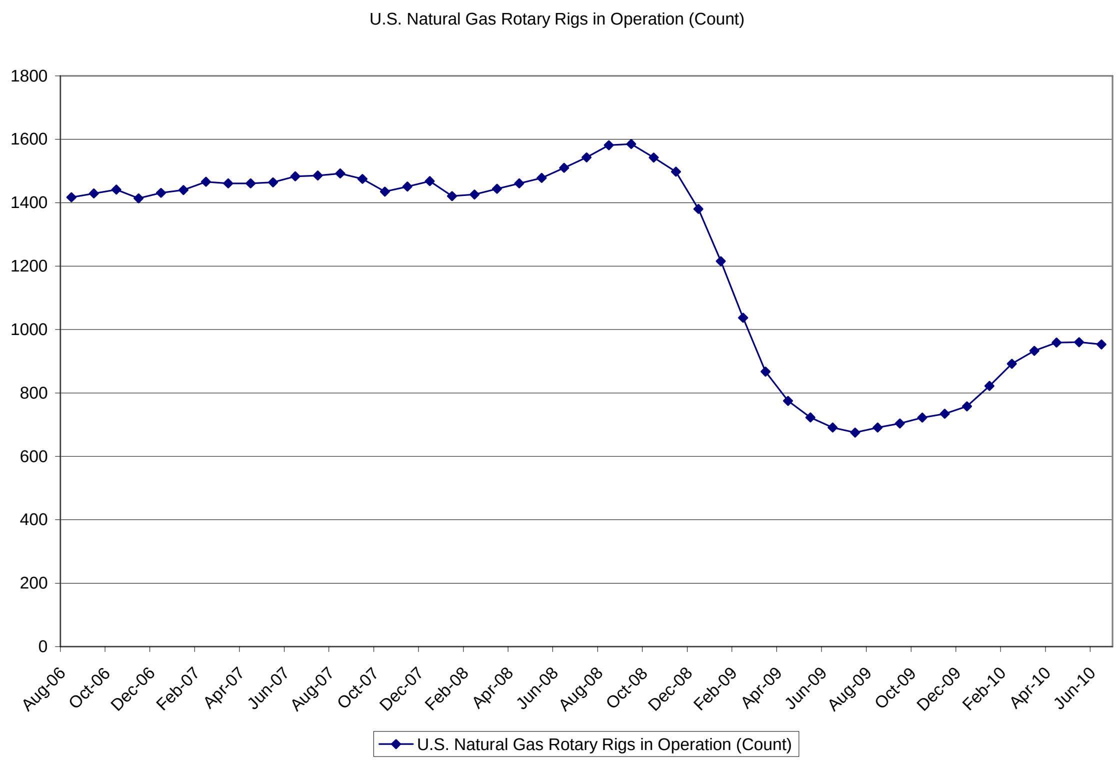
Natural Gas Statistics

Figure 1 – Natural Gas Production



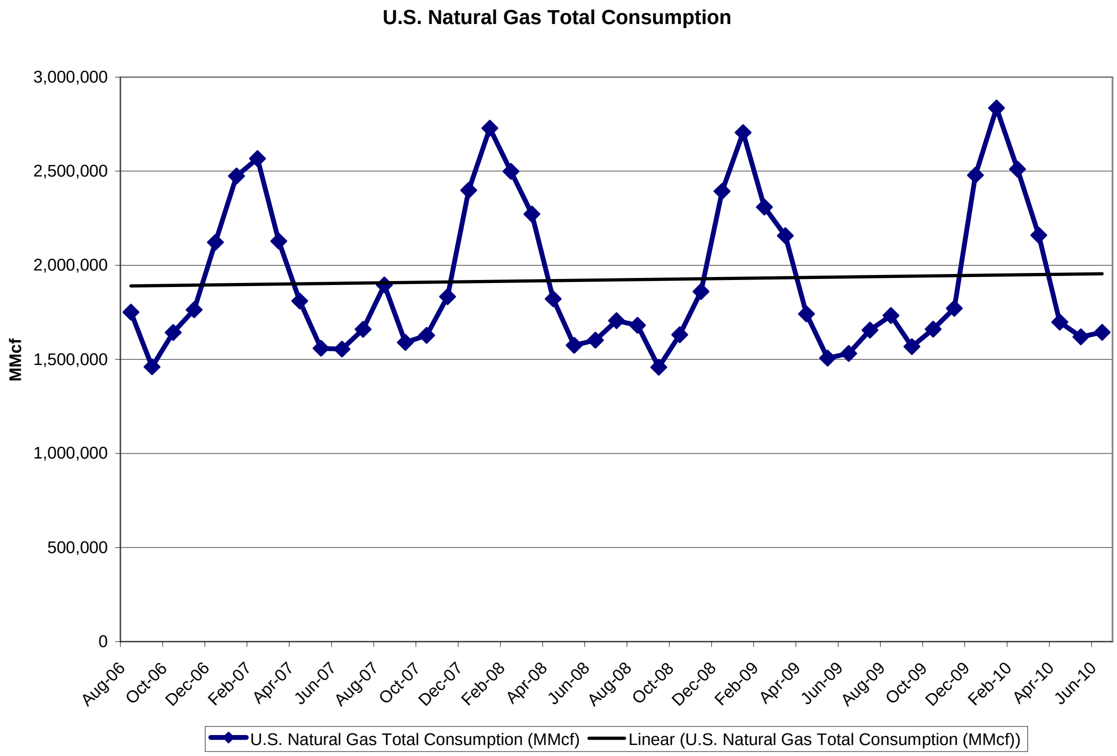
Source: United States Department of Energy, Energy Information Administration, August 30, 2010

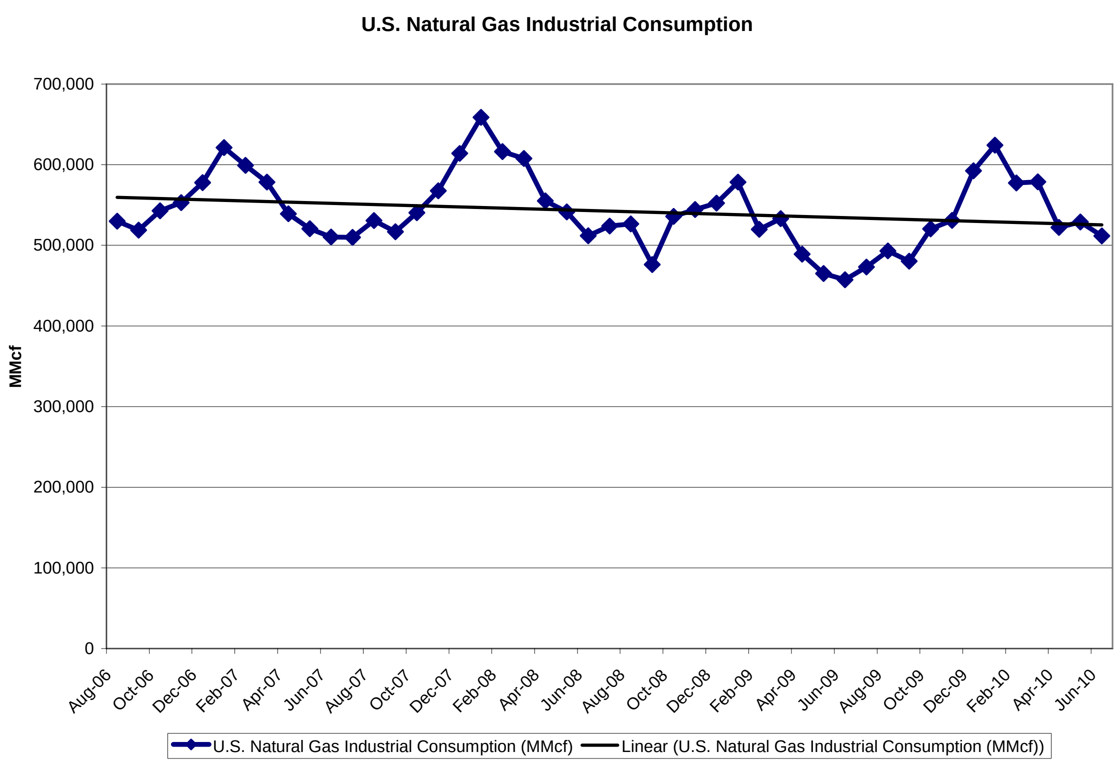
Figure 2 – Natural Gas Rig Count



Source: United States Department of Energy, Energy Information Administration, September 2, 2010.

Figure 3 – U.S. Natural Gas Total Consumption and Industrial Consumption





Source: United States Department of Energy, Energy Information Administration, August 30, 2010.

Figure 4 – Natural Gas Storage

Weekly Natural Gas Storage Report

Released: September 16, 2010 at 10:30 a.m. (eastern time) for the Week Ending September 10, 2010.
Next Release: September 23, 2010

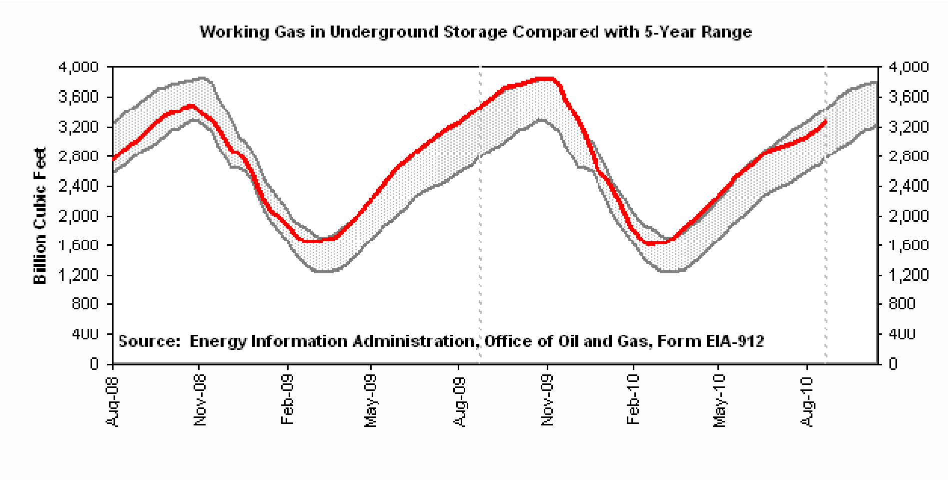
Working Gas in Underground Storage, Lower 48

other formats: Summary TXT CSV

Region	Stocks in billion cubic feet (Bcf)			Historical Comparisons			
				Year Ago (09/10/09)		5-Year (2005-2009) Average	
	09/10/10	09/03/10	Change	Stocks (Bcf)	% Change	Stocks (Bcf)	% Change
East	1,766	1,712	54	1,870	-5.6	1,759	0.4
West	491	478	13	471	4.2	418	17.5
Producing	1,010	974	36	1,108	-8.8	899	12.3
Total	**3,267**	**3,164**	**103**	**3,449**	**-5.3**	**3,075**	**6.2**

Notes and Definitions

Summary
Working gas in storage was 3,267 Bcf as of Friday, September 10, 2010, according to EIA estimates. This represents a net increase of 103 Bcf from the previous week. Stocks were 182 Bcf less than last year at this time and 192 Bcf above the 5-year average of 3,075 Bcf. In the East Region, stocks were 7 Bcf above the 5-year average following net injections of 54 Bcf. Stocks in the Producing Region were 111 Bcf above the 5-year average of 899 Bcf after a net injection of 36 Bcf. Stocks in the West Region were 73 Bcf above the 5-year average after a net addition of 13 Bcf. At 3,267 Bcf, total working gas is within the 5-year historical range.



Note: The shaded area indicates the range between the historical minimum and maximum values for the weekly series from 2005 through 2009.
Source: Form EIA-912, "Weekly Underground Natural Gas Storage Report." The dashed vertical lines indicate current and year-ago weekly periods.

Source: United States Department of Energy, Energy Information Administration, September 16, 2010.

Attachment E

Updated Inputs and Assumptions Used in BPA Analysis

Updated Inputs and Assumptions Used in BPA Analysis

The Market Price Forecast Study from the WP-10 rate proceeding indicates that there are three primary drivers for the market price forecast: the load forecast, the natural gas price forecast, and assumptions about hydroelectric generation. . (*See* WP-10-FS-BPA-03 at 8.) The Market Price Forecast Study also goes on to detail how these main drivers are used in the forecasting model, AURORA$^{xmp®}$, to calculate market-clearing prices. AURORA$^{xmp®}$ is a commercially available production cost model developed and sold by a company by the name of EPIS, Inc. (See WP-10-FS-BPA-03 beginning at 1.) This section outlines the assumptions for these three areas, as well as other pertinent assumptions that BPA has used for the calculation of the Equivalent Benefits Test.

Section 3.2 of the Market Price Forecast Study (see WP-10-FS-BPA-03, beginning at 8) outlines BPA's load forecast used in the WP-10 rate proceeding, the methodology for its development, and its use as an input to BPA's electricity price forecasts. For the base-year load forecast used in AURORA$^{xmp®}$, the WECC 10-Year Coordinated Plan Summary (2006-2015) was used in WP-10. That load forecast has since been discontinued. In its place, the load forecast supplied by EPIS (Owners of AURORA$^{xmp®}$) was used in all regions of the WECC for this evaluation of the Equivalent Benefits Test, except for California where data from the California Energy Commission was used.

Section 3.3 of the Market Price Forecast Study (see WP-10-FS-BPA-03, beginning on p. 11) outlines BPA's natural gas price forecast used in the WP-10 rate proceeding, the methodology for its development, and its use as an input to BPA's electricity price forecasts. To analyze the Extended Initial Period, BPA employed its most recent published natural gas price forecast, which used the same methodology. This recent natural gas price forecast is an update to what BPA used in its WP-10 rate proceeding as an input to its forecast of electricity prices and is identical to the medium case forecast of natural gas prices used in BPA's Resource Program released September 2010.

BPA's recent distribution of streamflow expectations for FY 2011 and FY 2012 contributed to the forecasts of hydroelectric generation – outputs of HYDSIM from late July and early August of 2010 – that were used for this evaluation of the Equivalent Benefits Test. Section 3.4 of the Market Price Forecast Study (see WP-10-FS-BPA-03, at 16) outlines the hydroelectric generation forecast used in the WP-10 rate proceeding, the methodology for its development, and its use as an input to BPA's electricity price forecasts. BPA's more recent forecasts of hydroelectric generation were developed in a consistent manner.

In addition, section 3.5 of the Market Price Forecast Study describes three other factors used in the WP-10 rate proceeding that were accounted for in the forecast of market prices. (See WP-10-FS-BPA-03, at 16-17.) BPA has updated one of these three factors for use in this analysis.[1] Specifically, wind capacity built in the Pacific Northwest is modeled to be consistent with Transmission Services' forecast of installed wind generation capacity in BPA's Balancing Authority Area. For example, that forecast of installed wind generation capacity averages 4,202 MW for the portion of FY 2012 covered by this analysis (October 2011 through May 2012).[2] All other renewable resource additions to address existing Renewable Portfolio Standards (RPS) are based on the Northwest Power and Conservation Council's (the "Council") forecast of RPS resource additions included in their *6th Power Plan*.

BPA held a rate case public workshop September 14, 2010 to address additional model changes that are being considered for the Initial Proposal in the 2012 rate proceeding. Those proposed model revisions under consideration include: transmission variability; wind variability; Columbia Generating Station (CGS) variability; impact of AB 32 in California; and changes to British Columbia and California Hydro assumptions.[3] Each of these model changes is used for this evaluation of the Equivalent Benefits Test, except because of the uncertainty regarding actions to be developed by California there is no carbon price assumed for California's implementation of AB 32.[4] At the September 14th workshop BPA staff also presented an RPS-based WECC-wide generation build forecast, which met with some criticism. After further consideration, a more reasonable approach was used that combines an updated forecast of PNW wind capacity along with other RPS resource additions forecast by the Council to address RPS in the model.

In recent rate cases, BPA has decreased the loads in Oregon, Washington and Northern Idaho by approximately 2,500 aMW each year when establishing market prices. (See WP-10-FS-BPA-03 at 7.) In light of the modeling changes discussed above, BPA is continuing to study the continued applicability of this load decrement. Removing this load decrement in this analysis is a conservative assumption that causes the market price forecast to be higher than it would otherwise be, *i.e.*, it biases the results against Equivalent Benefits being achieved..

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[1] As in WP-10, AURORA[xmp®] did not retire or add resources in the PNW during FY 2011 or FY 2012 and BPA continues to model the extended outage scheduled for Columbia Generating Station in 2011 as an 87-day outage from 4/9/2011 through 7/4/2011.

[2] This updates the assumption from Transmission Services' forecast of 3,593 MW of calendar year 2011 wind resources in BPA's Balancing Authority Area used in the WP-10 rate proceeding.

[3] *2012 BPA Rate Case Customer Workshop – AURORA*, September 14, 2010. *See* Attachment F.

[4] In 2006, the Legislature passed and Governor Schwarzenegger signed AB 32, the Global Warming Solutions Act of 2006, which set the 2020 greenhouse gas emissions reduction goal into law. It directed the California Air Resources Board (ARB or Board) to begin developing discrete early actions to reduce greenhouse gases while also preparing a scoping plan to identify how best to reach the 2020 limit. The scoping plan, approved by the ARB December 12, 2008, provides the outline for actions to reduce greenhouse gases in California. The approved scoping plan indicates how these emission reductions will be achieved from significant greenhouse gas sources via regulations, market mechanisms and other actions. (See California Environmental Protection Agency, Air Resources Board website, http://www.arb.ca.gov/cc/ab32/ab32.htm)

For this Equivalent Benefits Test and consistent with the Alcoa ROD, the 2010 White Book and the WP-10 Rate Proceeding, BPA assumed 30-minute persistence forecasting for wind. This persistence level uses the least amount of balancing reserves from the Federal Base System (FCRPS) to follow variable generation from renewable resources that are intermittent, such as wind.

Consistent with the Alcoa ROD the FY 2011-2012 inventory (resources minus loads) values used for the analyses of the demand shift and avoided transmission and ancillary services expenses were based on using 3,500 simulated load and resource conditions for each month of the Extended Initial Period. However, the analysis assumed DSI load is 340 aMW. The Alcoa load under the Block Contract represents 320 aMW out of the 340 aMW DSI load assumed, or 94.1%.

Consistent with the Alcoa ROD and the WP-10 Rate Proceeding, BPA has employed a recent version of AURORA$^{xmp®}$ for its market price forecast. The version of AURORA$^{xmp®}$ used in the Alcoa ROD analyses was 9.2 (see WP-10-FS-BPA-03 at 18). BPA has since adopted the most recent version of AURORA$^{xmp®}$ provided by EPIS, Inc.,verion 10.0.1026, which is used in this analysis.

Consistent with the Alcoa ROD, BPA believes that the forward market is an important benchmark of near-term market prices, but it only comes into play if one is willing to lock in a forward purchase or sale for the period quoted. BPA believes price forecasts, in general, more accurately gauge prices that BPA would actually experience over longer time periods because BPA tends to manage most of its inventory on a shorter term basis.[5]

[5] See Alcoa ROD at 49-54.

Attachment F

2012 BPA Rate Case Customer Workshop – AURORA, September 14, 2010

2012 BPA Rate Case Customer Workshop

AURORA

September 14, 2010

Introduction

- Purpose of this workshop
  - Introduce inputs being examined that could replace AURORA defaults for market price forecasting at BPA
- Note that the information provided is a set of working data. It points out some of the changes to AURORA default data that we are considering. The information contained is a work in progress and is subject to change for the Initial Proposal.

What is AURORA?

- AURORA is electricity market forecasting software that simulates WECC-wide dispatch (a production-cost model)
  - AURORA includes a default dataset that “out of the box” can produce a forecast
  - AURORA simulates the dispatch of every generator in WECC
  - AURORA includes a forecast of generators that will be built in WECC and dispatches those generators when they are operational within the timeframe of an AURORA study

Why We Change Default Data in AURORA

- We have always updated default data when appropriate, some of the reasons include:
  - AURORA has a biannual update to the default dataset. Some updates, such as natural gas price forecast, are done on a much more regular basis at BPA.
  - BPA monitors market information and uses it to inform AURORA inputs.
  - BPA has some information that has greater detail than the defaults, e.g. regional hydro generation from HydSim.
  - We implement risk modeling, i.e. varying inputs to test a range of possible future market prices. This allows us to forecast expectation of market prices and assign probabilities to market price levels.

Changes to AURORA Defaults

- Changes that were included in the market price risk modeling for WP-10 that may be included in BPA-12 with the underlying data having been updated:
  - HydSim 70 water year PNW regional hydro generation potential
  - Northwest and California Load variability
  - Natural gas price variability
- Other model changes that are being investigated:
  - Transmission variability
  - Wind variability
  - CGS variability
  - Modeling of the impact of AB 32 in California
  - RPS-based WECC-wide generation build forecast
- Changes to BC and California Hydro records are being researched

HydSim 70 Water Year PNW Regional Hydro Generation Potential

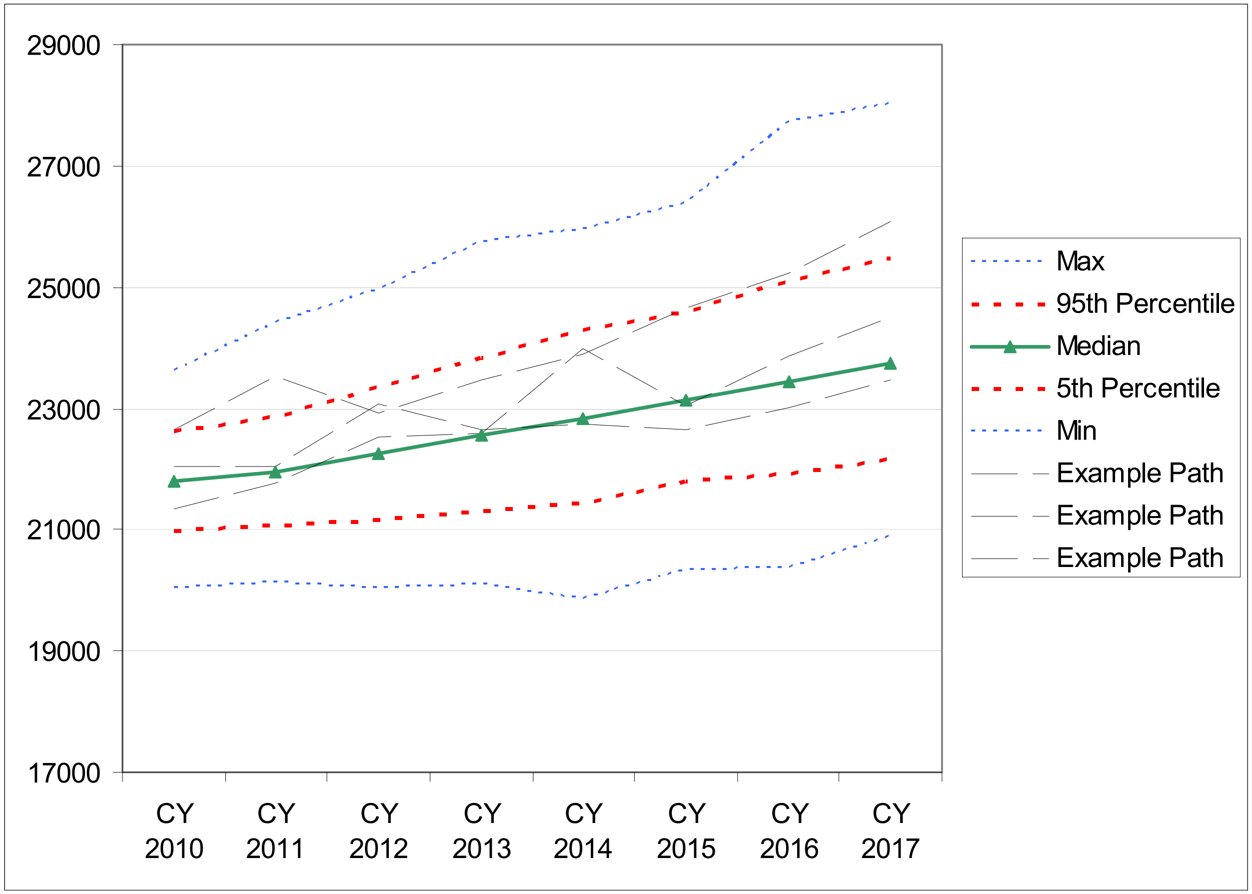
- AURORA uses a HydSim record that gives the total potential generation for the regional hydro system
  - Note: this does not translate directly to hydro generation output in AURORA, not all potential hydro energy is used
- The table on the right gives the averages of the potential record by month and for the whole record

	MW
Oct	11243
Nov	13619
Dec	15509
Jan	17472
Feb	16393
Mar	15214
1-Apr	16969
16-Apr	17251
May	20483
Jun	20155
Jul	16198
1-Aug	13498
16-Aug	12147
Sep	11527
Annual	15638

Load Variability

- AURORA uses a load forecast and a risk model as input
- Regional loads for the Northwest are based on AURORA defaults
- California loads are based on CEC data
- Risk models are used to capture variability of the loads in both the Northwest and California

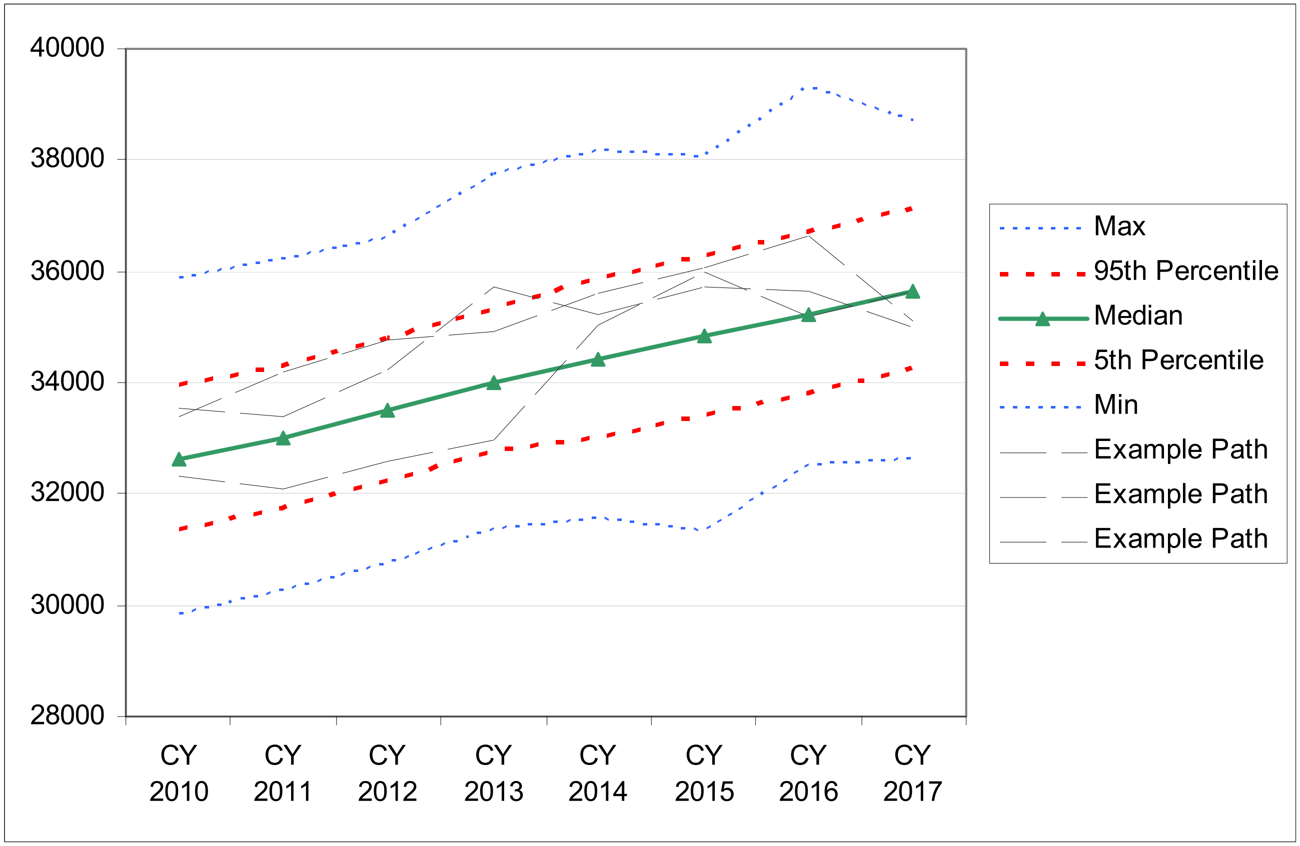
PNW Load Variability



Median Load

2010	21786
2011	21957
2012	22260
2013	22556
2014	22839
2015	23141
2016	23437
2017	23746

California Load Variability

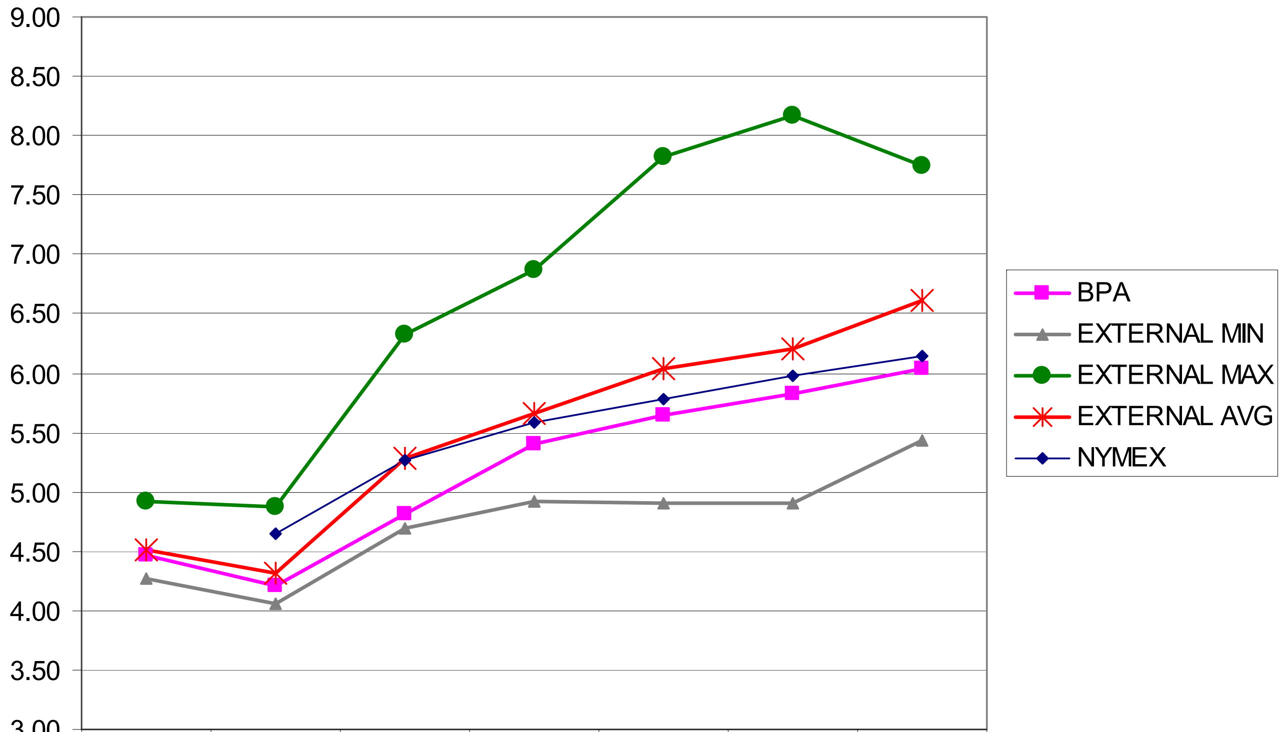


Median Load

2010	32640
2011	32997
2012	33495
2013	34010
2014	34409
2015	34823
2016	35238
2017	35651

Draft Natural Gas Forecast

BPA Henry Hub price outlook (nominal $/MMbtu)



	2010	2011	2012	2013	2014	2015	2016
BPA	4.46	4.21	4.81	5.40	5.64	5.83	6.04
EXTERNAL MIN	4.27	4.05	4.70	4.92	4.91	4.90	5.44
EXTERNAL MAX	4.91	4.87	6.33	6.87	7.82	8.16	7.74
EXTERNAL AVG	4.52	4.31	5.28	5.66	6.04	6.21	6.61
NYMEX		4.64	5.26	5.58	5.78	5.97	6.15

Caveats

- Subject to revision for Initial Proposal
- While clear consensus exists for short term, long term characterized by numerous uncertainties, each of which has a potentially dramatic effect on prices
- Divergence of external forecasts likely reflects probabilistic analysis of these uncertainties
- NYMEX does not equal cash!

Current state

- Supply: “Shale gale” dominant factor in market
  - Abundance of supply at low costs
  - Advances in drilling technology
  - Rush to production
  - High levels of production despite low prices
- Demand: Where will it come from?
  - Economic recession persistent with slower than expected recovery
  - Because of high levels of both supply and storage, large incremental growth necessary to provide upward pressure on prices
  - Tough to imagine scenarios that create this demand without significant policy implementation

Near term (2010-2011)

- Hot summer in most of nation provides no support for prices – large decline in both cash and futures markets during last 3 months
- Unchecked production with persistently high storage
- Mild winter and associated withdrawals projected for East Coast demand markets
- Sluggish recovery with little to no improvement in industrial or power sector demand
- 2011 consensus opinion in very tight range at depressed levels relative to 2010

Medium Term (2012-2013)

- Modest strengthening of prices over this period
- Economy should be on a better track by this point
- Demand increase led by power sector as coal-to-gas switching continues
- Recovery or medium/long term growth prospects for Industrial debatable – especially in dry gas (natural gas liquids potentially another story but major infrastructural issues)
- Producers able to exercise greater degree of control over market and attempt to restore supply/demand balance
- Higher price threshold for encouraging independent production
- Upward price trajectory supported by EPA emission regulations and continuing growth of renewables

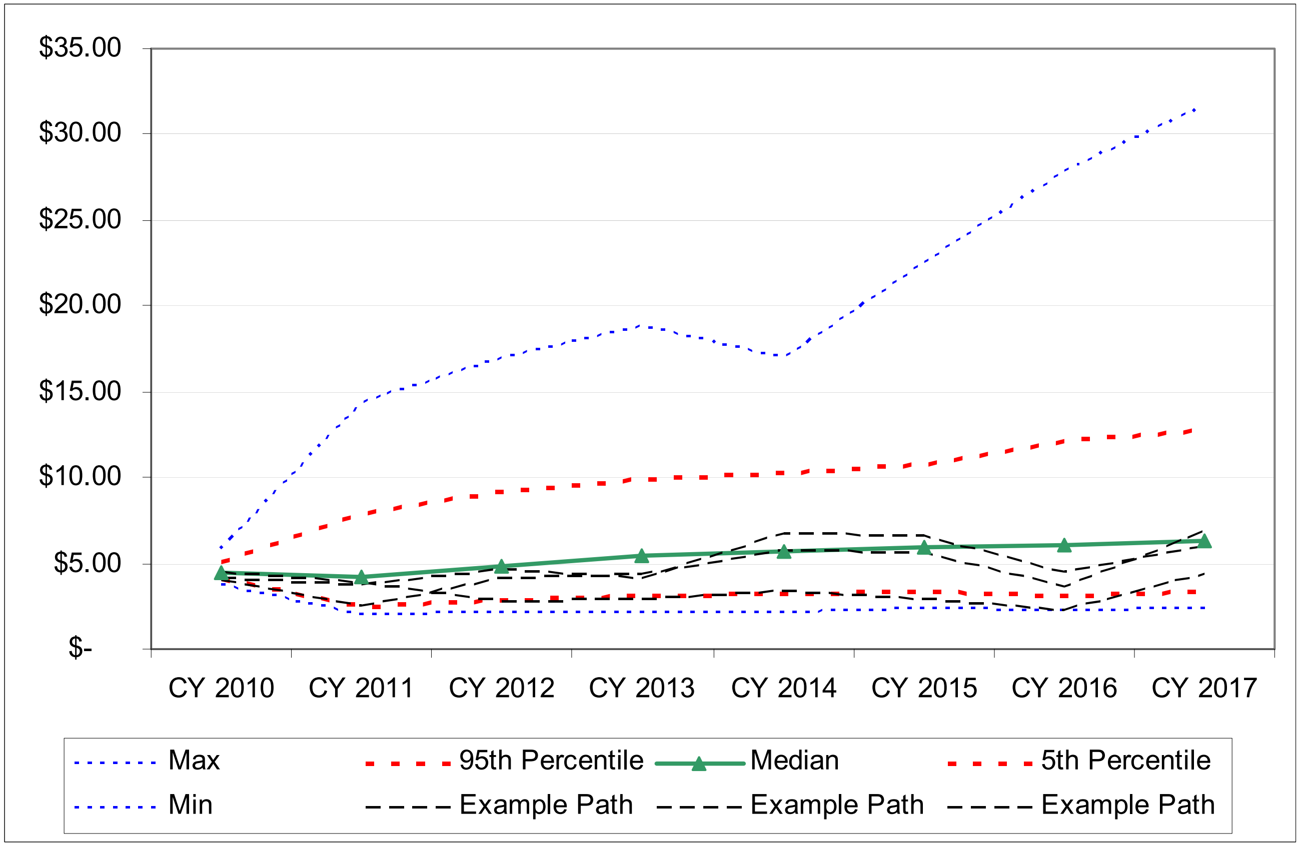
Long term (2014-2016)

- Overall flattening of price
- Journey towards price equilibrium – in this equilibrium, supply still main driver of prices
- Pipeline development and flows from major shale plays establish clearer correlation of demand centers with regionalized supply areas
- Expect lower seasonal volatility
- Pipeline constraints gradually lower, further reducing seasonal or event driven volatility

Future Uncertainties

- EPA study on hydraulic fracturing
  - Initial study results planned for late 2012
  - Event most likely to both occur and have definitive effect on industry
- Major policy initiatives
  - Further emissions controls / large scale energy bill
  - Investment in natural gas vehicles
  - Increased construction of CCGTs to accompany growing amount of wind generation
- Other factors
  - Domestic manufacturing growth could exceed estimates
  - Further incremental technologic advances in drilling techniques
  - Worldwide demand for LNG distorts breakeven price for LNG export
  - Consolidation of industry and tough regulatory environment

Natural Gas Variability



Note: Prices in Nominal $

	5th-Perc	Median	95th-Perc
2010	$ 4.07	$ 4.47	$ 5.01
2011	$ 2.49	$ 4.25	$ 7.87
2012	$ 2.79	$ 4.86	$ 9.12
2013	$ 3.13	$ 5.49	$ 9.84
2014	$ 3.24	$ 5.72	$ 10.27
2015	$ 3.38	$ 5.93	$ 10.72
2016	$ 3.14	$ 6.11	$ 12.10
2017	$ 3.29	$ 6.28	$ 12.68

Possible Approach to Transmission Variability

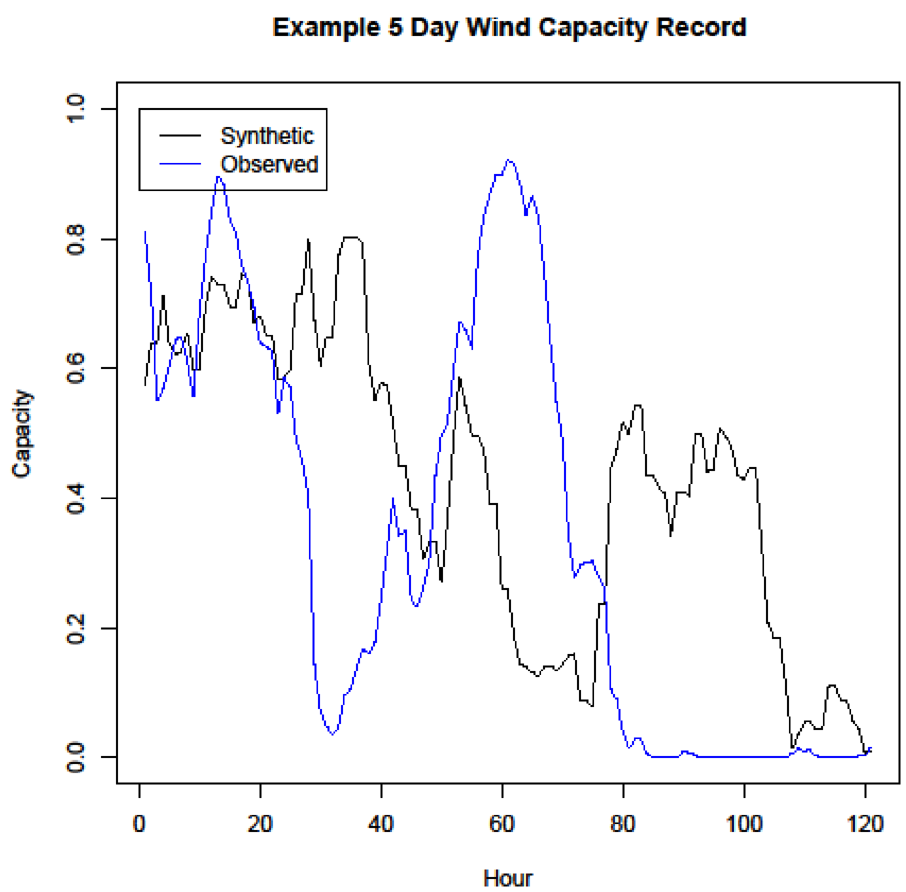
- Three transmission paths gamed
  - COI North to South (AC – 4800 MW in AURORA)
  - DC Intertie North to South (DC – 3100 MW in AURORA)
  - BC Intertie North to South (BC – 3150 MW in AURORA)
- 200 games with transmission transfer capability limited based on transmission scheduling limit
- Average percentage rating of transmission lines shown below
  - AURORA defaults to 80% for COI and DC line and 100% for BC line

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
AC	88.4%	86.1%	80.3%	78.1%	80.8%	82.4%	88.8%	89.3%	81.9%	82.3%	82.4%	87.5%
DC	73.3%	72.1%	66.6%	79.7%	84.3%	86.2%	83.9%	86.4%	75.3%	32.2%	56.7%	76.4%
BC	79.3%	77.1%	70.0%	66.8%	63.6%	61.7%	66.9%	75.5%	68.7%	70.0%	70.4%	74.3%

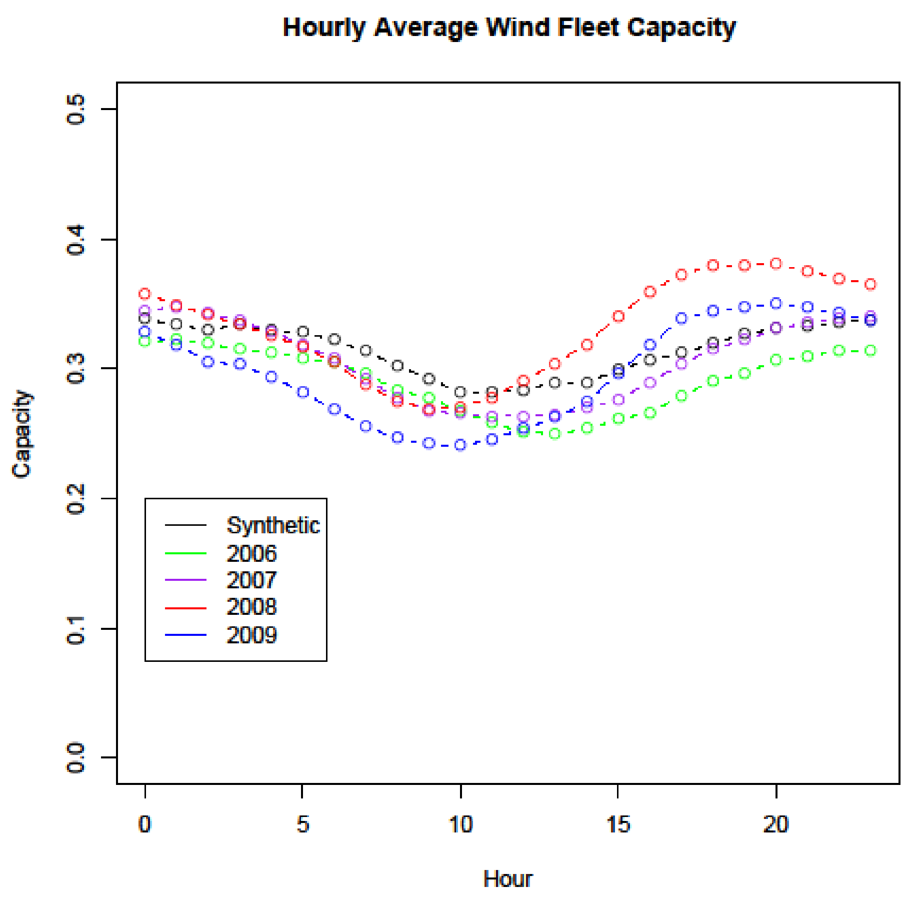
Possible Approach to Wind Variability

- 30 wind games created with a kth-Nearest-Neighbor (kNN) algorithm (also known as a local bootstrap) to have a realistic hourly wind shape and be consistent in monthly energy and annual energy variations seen in the BPA wind fleets historical record.

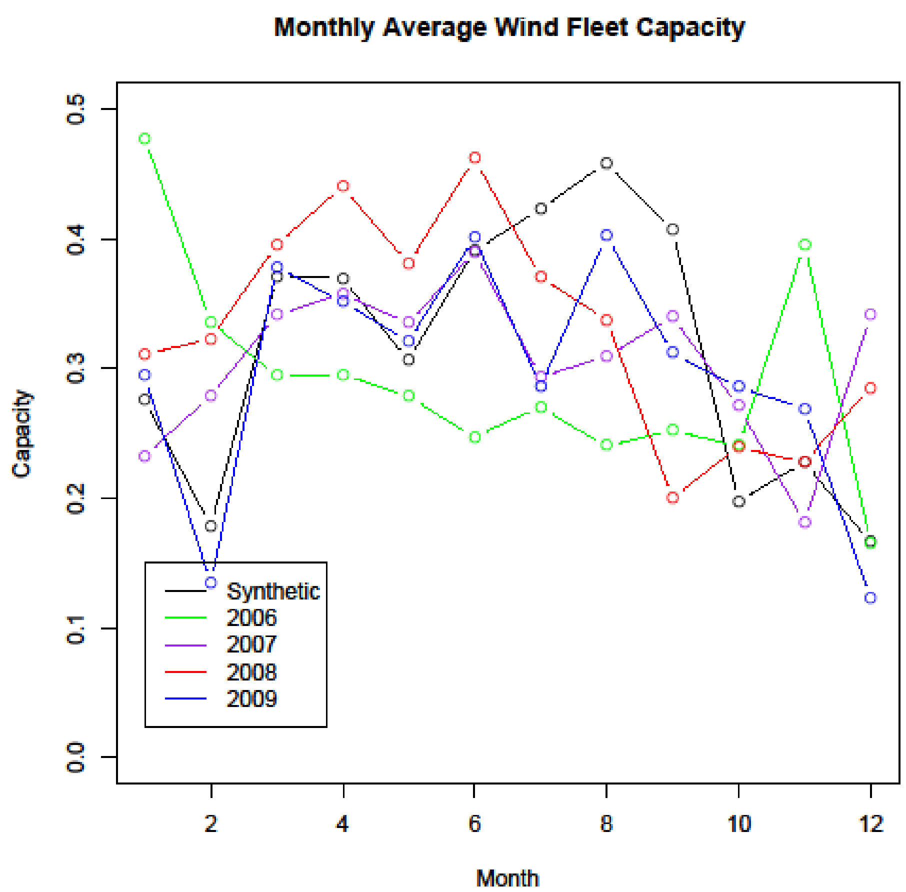
Example Wind Game Summary



Example Wind Game Summary

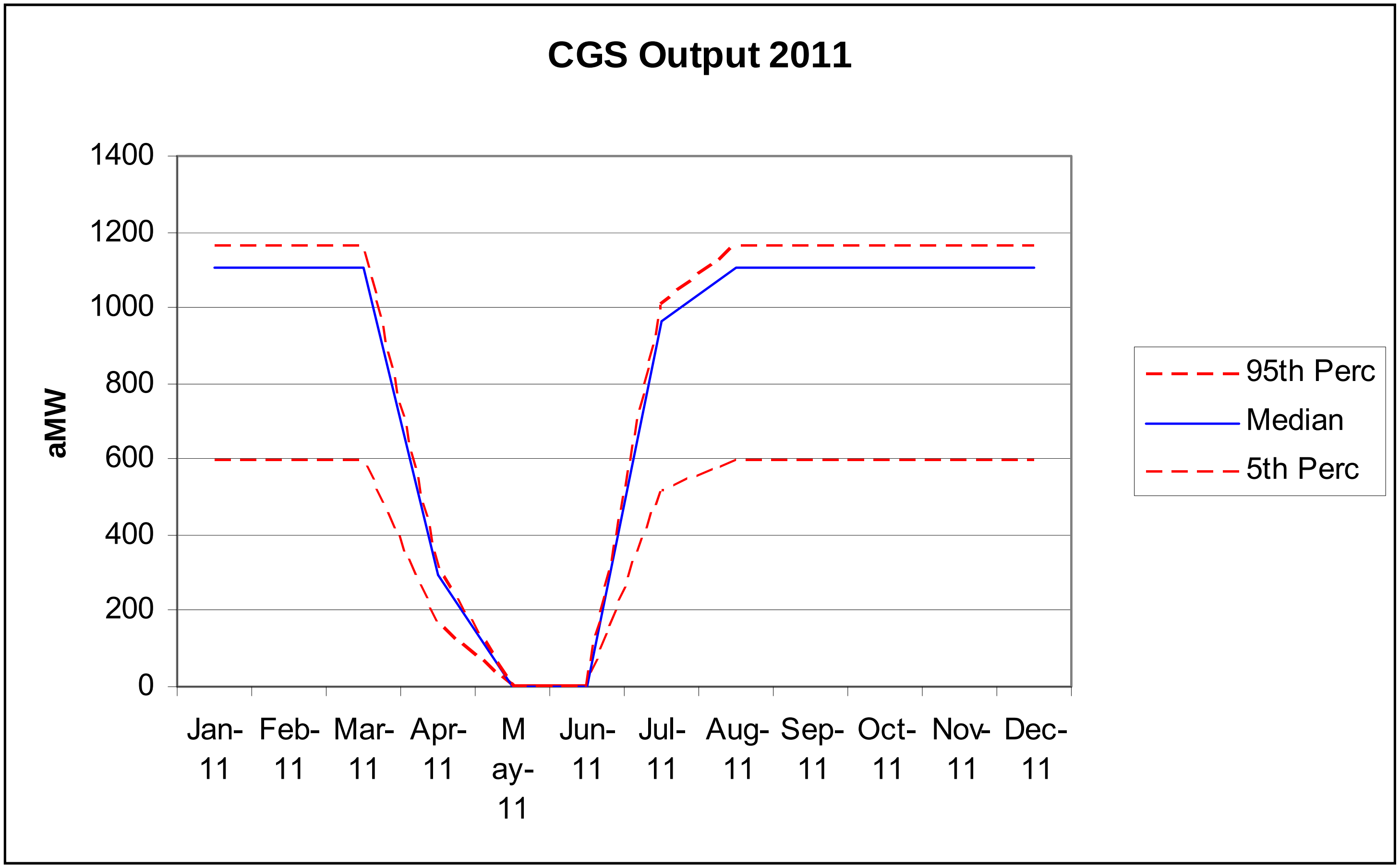


Example Wind Game Summary



CGS Variability

- AURORA CGS gaming scheme updated to match the inventory gaming as used in the WP10 rate case



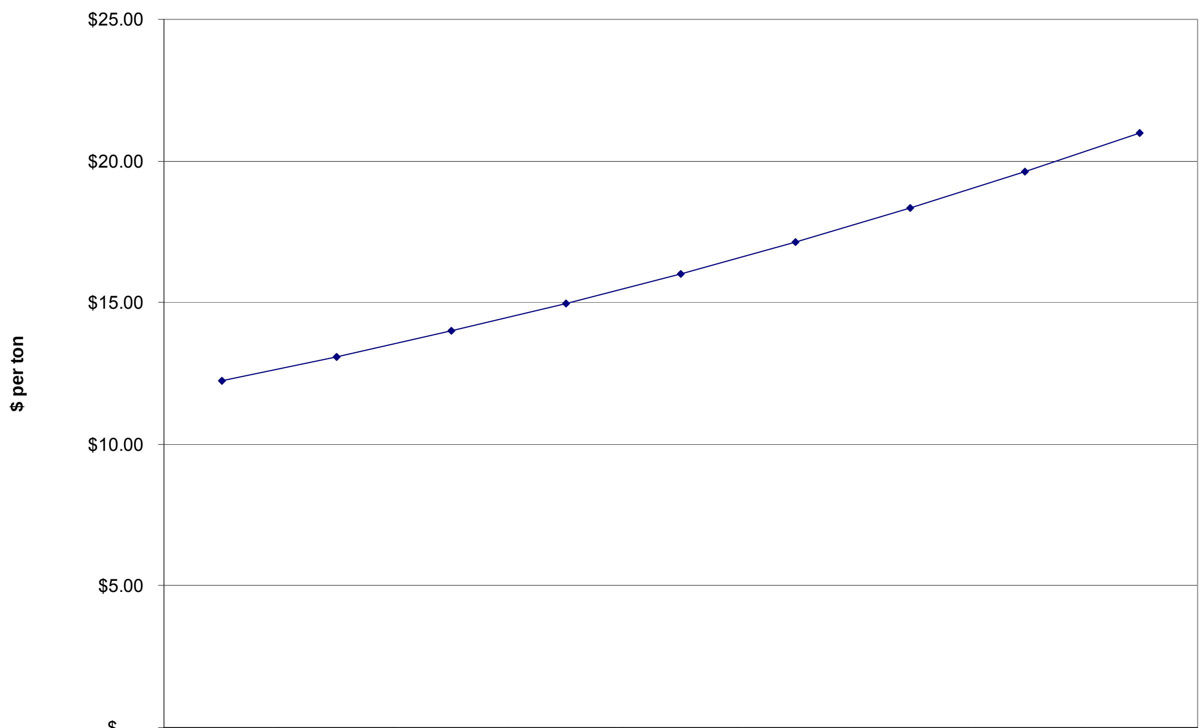
Proposal for California Carbon Emission Price

- Implemented in the model as a direct emission price on California generators
- Imported power is given a 1000 lb/MWh price which is added to wheeling charges on transmission lines going into California
- Low-level carbon price is included as a conservative assumption
- Currently modeling carbon pricing as starting in 2012, should this be shifted?
- Other ideas?

Proposal for California Carbon Emission Price

- California generators have a carbon price associated with emissions based on a CARB forecast. AURORA has a default carbon price forecast that is replaced in California by these figures and set to zero for other generators.

CARB CO2 Cost Projection



	2012	2013	2014	2015	2016	2017	2018	2019	2020
CO2 Cost	$12.22	$13.08	$13.99	$14.97	$16.02	$17.14	$18.34	$19.63	$21.00

RPS-based WECC-wide Generation Build Forecast

- BPA implemented a RPS-based resource build forecast based on System Optimizer a capacity expansion model is used to:
  - simultaneously consider generation and transmission alternatives
  - develop long-term 20-30 year resource plans including type, size, location, and timing of capital projects
  - access production cost details
  - evaluate a range of investment choices including renewables, DSM, unit retirements, and transmission upgrades
  - consider imports and exports between regions

…given a reserve margin requirement or an LOLP constraint

RPS-based WECC-wide Generation Build Forecast