Cash Flow Analysis Methodology and Assumptions

Methodology

As a year progresses, the range of potential runoff uncertainty narrows because fewer historical water years are included in the sample used to analyze the remainder of the year. This water year is in the extreme tail of all potential runoff scenarios, and there are insufficient observations in the historical record to approximate the range of uncertainty remaining in this water year. Hence, eight synthetic scenarios, which are comprised of a range of potential precipitation and runoff patterns for the remainder of the year, are used to generate potential surplus or deficit generation capability.

Price uncertainty is applied to the potential generation surplus or deficit. In the scenarios, which demonstrate deficits, the range of potential prices is used to calculate a range of power purchase expenses. In the surplus scenarios, the surplus is first reduced to approximate the storage volume necessary to increase long-term reliability. Then, the remaining surplus is sold at the range of potential power prices and/or spilled. The spill scenario dictates the spill volume, then all remaining surplus, if any, is sold.

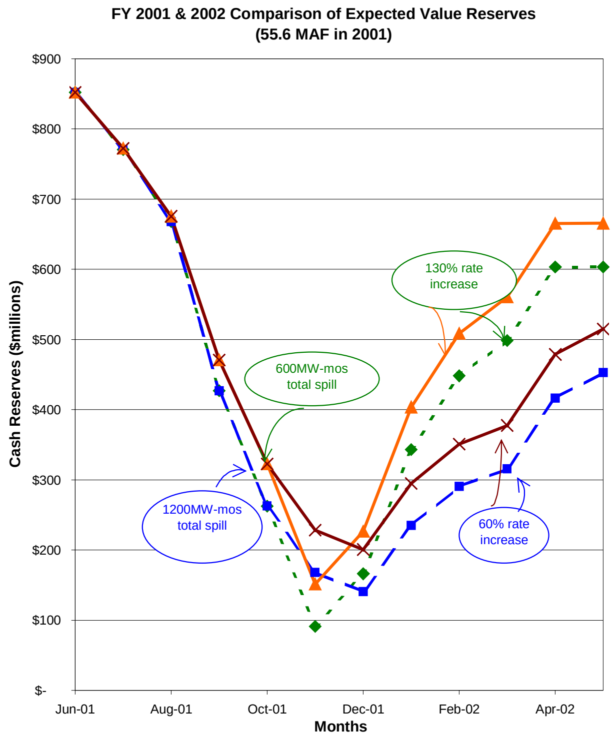
In addition to variability in generation and power prices, random Columbia Generation Station outages and load variability are included in the analysis. Load variability is not modeled in FY2002 since the augmentation scenarios include two different load scenarios.

The analysis for FY2002 resumes modeling historical water years, however anticipates a somewhat drier fall than average.

For the most part BPA expenses are spread evenly 1/12 per month with the exception of power purchase payments. Most revenues are shaped consistent with sales expectations with the exception of Slice revenues in FY2002 which are 1/12 per month.

From the above methodology and data, models generate monthly distributions of net revenues. The resulting scenarios are adjusted for cash transactions. Non-cash expenses are removed and replaced with cash payments consistent with the monthly shape of cash payments to Treasury and vendors. Monthly 4(h)(10)© revenues are applied to monthly Treasury payments. Net billing logic diverts some of the cash receipts from power and transmission sales to Energy Northwest until the Energy Northwest budget is satisfied.

The result of these cash adjustments is a distribution of potential reserve balances by month. From this distribution, models calculate the probability of having particular reserve levels in each month as shown in the illustrative chart below.



Cash Flow
(Probability of < $0 Reserves)

Total Spring and Summer Spill - FY2001

	600MW-mos spill 60% rate increase	*600MW-mos spill 130% rate increase*	*1200MW-mos spill 60% rate increase*	*1200MW-mos spill 130% rate increase*
Jun-01	0.0%	0.0%	0.0%	0.0%
Jul-01	0.0%	0.0%	0.0%	0.0%
Aug-01	0.0%	0.0%	0.0%	0.0%
Sep-01	1.6%	1.6%	1.7%	1.7%
Oct-01	5.5%	5.5%	8.2%	8.2%
Nov-01	8.4%	13.6%	13.5%	**21.3%**
Dec-01	10.9%	8.9%	17.4%	14.5%
Jan-02	6.4%	4.2%	10.6%	5.8%
Feb-02	9.6%	6.1%	11.8%	7.6%
Mar-02	13.0%	9.1%	14.7%	10.5%
Apr-02	11.7%	9.8%	13.5%	10.5%
May-02	12.4%	10.9%	13.3%	11.4%

FY2001 Ending Reserve Levels
(Probability of < $300M Reserves)

Sep-01	7.8%	7.8%	12.8%	12.8%

Assumptions:
1. Cal ISO/PX don't pay anything due.
2. 4H10c credits applied monthly starting in February.

Assumptions consistent with 6/15/2001 financial analysis

FY2001

- Uses 8 synthetic weather year traces to generate streamflows whose weighted average is equal to 55.6MAF. The range of potential runoff conditions is 52.5 – 60 MAF. These traces have not been updated since late May and do not reflect actual runoff since then.
- Assumes Columbia Generating Station return to service on June 25.
- The amount due to BPA from the Cal ISO and PX is approximately $80-85 million. BPA does not expect to receive this payment for at least another year if at all.
- The cost of the purchased power since early June has not been included in this analysis
- Actual financial results through the end of May 2001 are included.
- Assumes additional $40M expense for proposed alternative fish measures for spring spill operations in FY2001.
- Stored to a total federal system content of 28,000 MW-mos in all cases (which is our conservative guess as to what the NWPPC results will show)
- Includes aluminum company and irrigation buydowns
- Assumes deal with Grant PUD doesn’t work

- Price assumptions:

Month	June '01	July '01	August '01	Sept. '01
Price	$50.05	$133.56	$172.26	$129.70

FY2002

- Hydro operations are modeled to achieve full bi-op flow and spill operation
- Wettest 1/3 of water years eliminated for Oct-Dec 2001
- Proportional draft returned to Canada in Jan-Mar 2002 in wettest water years – in drier years the return is delayed until 2003 or beyond
- Reflects completed purchase/buy down transactions through May 29, 2001.
- Potential rate increase scenarios reflect Load Based CRAC (LBCRAC) only.
- Financial Based CRAC (FBCRAC) doesn't trigger prospectively in these results in either rate scenario because expected value reserves are projected to be greater than $300M at the end of Sept 2001 in both spill scenarios. The cash model doesn't calculate (FBCRAC) retroactively.
- LBCRAC rate increase scenarios for fiscal year 2002 are intended to represent potential scenarios of augmentation outcomes for FY2002. The two scenarios selected represent potential average rate increases for the year of 60% and 130%. The two 6-month rates that are assumed to underlie the 60% rate are 62% and 58% and for the 130% rate are 152% and 104%.
- Slice is modeled at 1600aMW.
- LBCRAC assumes augmentation to critical water.
- The shape of expenses and revenues changes significantly in the next rate period. The magnitude of the augmentation amount drives the level of power purchase requirements and the LBCRAC level.
- In October, hydro studies are requiring the storage of water for chum salmon operations, so some amount of power is purchased in every scenario that month. Consequently there are payments for power purchases in every scenario in November.
- The impact of net billing, the payment from most public customers for power and transmission purchases directly to Energy Northwest, differs noticeably depending upon the LBCRAC level. The higher the rate is, the more cash flows to Energy Northwest. However, the duration of the cash flows is shorter than when the rate is lower. Energy Northwest fiscal year starts in July. June bills commence the net billing process for Energy Northwest receipts in July.
- The FY2002 Rate Case projects about 2415 aMW of Load Following sales on average over the 5 year period. Non-Load Following sales of about 1815 aMW are projected for the period. Slice sales total 1600 aMW. Projected presubscription sales total about 840 aMW over the period. Of these sales only for those of the Load Following variety will BPA realize price-induced reductions. For the Non-Load Following (Block) and Slice sales BPA's customer utilities may experience load reductions but they will not be passed on to BPA, any response would simply serve to reduce market purchases or increase market sales. In the case of the presubscription sales, since there is no rate impact we would expect no price-induced load response.

- Price Assumptions

Month	Oct 01	Nov 01	Dec 01	Jan 02	Feb 02	Mar 02	Apr 02	May 02
Price	$226.30	$185.17	$241.42	$220.28	$165.47	$109.06	$68.24	$57.30