UNITED STATES DEPARTMENT OF ENERGY

BEFORE THE

BONNEVILLE POWER ADMINISTRATION

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	)	
2012 RATE ADJUSTMENT	)	**Docket Number BP-12**
PROCEEDING	)	
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	)	

DIRECT TESTIMONY

OF

NORTHWEST REQUIREMENTS UTILITIES, PACIFIC NORTHWEST GENERATING COOPERATIVE AND WESTERN MONTANA GENERATION AND TRANSMISSION COOPERATIVE

WITNESSES:

GEOFFREY H. CARR

DOUGLAS R. BRAWLEY

WILLIAM K. DRUMMOND

SUBJECTS: TRM Rate Design Effects and the Rate Increase, Demand Charge, Load Forecasts, Green Energy Premiums, Non-slice Cost Pool, Risk Mitigation, General Rate Schedule Provisions, and Generation Inputs Policy.

January 21, 2011

Q. Who is sponsoring this testimony?

A. The sponsors of this testimony are Geoffrey H. Carr (BP-12-Q-NR-01-E01), Douglas R. Brawley (BP-12-Q-PN-02), and William K. Drummond (BP-12-Q-WM-01-E01).

TRM Rate Design Effects and the Rate Increase

Q. What is the purpose of this portion of your testimony?

A. We describe the BP-12 wholesale power rate effects on NRU, PNGC and WMG&T's membership.

Q. What are the main implications of this rate proceeding?

A. This is the first rate proceeding where the BPA's Tiered Rate Methodology (TRM) is being implemented. Implementation of the TRM is the biggest single change to BPA's rate design in nearly three decades. At the same time BPA's costs are increasing. This has the effect of a 9.2 percent average rate increase on BPA's Non-Slice customers. This rate increase is before the possible implementation of any cost recovery adjustment clause that could trigger in FY 2012 or 2013. *See* BP-12-E-BPA-11, Table 1, p. 51. In contrast to prior rate cases, individual customers are affected in significantly different ways.

Q. Did you participate in the development of the TRM?

A. Staff members from NRU and PNGC participated in all aspects of the development of the TRM. Staff members from WMG&T were also actively involved in the TRM development. This includes the witnesses on this panel.

Q. Is BPA's implementation of the TRM in this rate proceeding consistent with the intent of the TRM?

A. We believe that, for the most part, BPA's Initial Proposal is consistent with the TRM. In making that statement we also include the results of the Unintended Consequence process of 2010 as described in the testimony of Bliven et. al. *See* BP-12-E-BPA-11, p. 31-32.

Q. In what areas might BPA's Initial Proposal be inconsistent with the TRM?

A. There are two areas of potential inconsistency. First is the development of the demand charge. Second, is the addition to the Non-Slice Cost Pool of costs that were not included on the Non-Slice Cost Pool table in the TRM. *See* Tiered Rate Methodology, TRM-12S-A-03, Table 2D Non-Slice Cost Pool, p. 126 (September 2009). We describe both of these areas of potential inconsistency below.

Q. When the TRM was being developed were you concerned about rate impacts?

A. Yes, because of BPA's proposed tiering of the rates and the very different rate design for the first tier, we were much attuned to the effect that rate design changes might have on BPA's priority firm customers. Rate design matters. For example, a rate design that relies more heavily on a demand charge to send price signals can have a significant impact on a customer with a "peakier" load. Depending upon the seasonality of the rates, a winter peaking customer may be affected more than a summer peaking customer. Working with the rest of the customers and BPA, we performed numerous wholesale power rate impact analyses to test the effect of different approaches to the TRM rate design to ensure that individual customers were not inordinately affected.

Q. Did you have a guiding principle as you looked at the rate impacts of different rate designs?

A. Yes. Our guiding principle was that no one customer would pay more than five percent more as a result of the move to the new rate design (with one exception for a customer experiencing very unique circumstances). There are two important caveats that need to be noted here. First, we were addressing a change to rate design, not a change to the overall revenues to be collected by the rates. The TRM rate design was created to recover the same amount of revenues for the same overall revenue requirement as the existing WP rate design. Second, we used the billing determinants that we had at that time. When we performed these analyses, the billing determinants we used were from the WP-07 final proposal. We understand that the billing determinants for demand change through time, seasonal energy shapes change and it is only to be expected that the forecast billing determinants for FY 2012 and 2013 will differ from those for FY 2008 and FY 2009.

Q. Recognizing the above caveats, how does the 2007 analysis compare to the forecast effect of the TRM for FY 2012?

A. In the 2007 analysis of the effect of the TRM (using FY 2008- 2009 data) only one utility had a more than five percent rate increase as a result of the move to the TRM. http://www.bpa.gov/power/pl/regionaldialogue/implementation/Previous-meeting-materials/Documents/2007/08_August/2007-08-14_BPA.pdf

Using the updated forecasts for FY 2012 and 2013 eight utilities have a five percent or higher rate increase due to the move to the TRM. This effect is largely due to the changes to the billing determinants over time and is shown on Graph D of the below presentation.

http://www.bpa.gov/corporate/ratecase/2012/docs/WedRateImpact_12_8_2010.pdf

Q. Combining the effects of the rate design change and the increase in revenue requirements, what is the impact of the rate design for the Non-Slice customers?

A. BPA estimates the average rate increase for the Non-Slice customers at 9.2%. *See* BP-12-E-BPA-11, p. 51. However the results vary widely with five customers seeing rate increases above 17% and seven customers seeing rate increases of below 6%. Fifty-four customers are forecast to have above average rate increases.

http://www.bpa.gov/corporate/ratecase/2012/docs/WedRateImpact_12_8_2010.pdf

Q. *Have your members expressed concern about the rate impacts of BP-12?*

A. Yes, they have. Most of the NRU/PNGC/WMG&T member utilities have service territories that have been significantly affected by the prolonged economic downturn that we have been enduring over the past few years. Many of these service territories are facing unemployment rates of 10% or higher. In this economic environment, many utilities will be forced to pass these rate increases onto customers that are already financially strapped. In addition, some members' load factors have deteriorated due to the downturn in the economy, amplifying the impact of a rate design heavily sensitive to incremental increases in the demand billing determinant. Our members look to NRU/PNGC/WMG&T to represent their interests in this BPA rate proceeding and to find ways to reduce the rate impact of the BPA proposal.

Q. *What recommendations do you have to mitigate the rate impact of this proposal on the members of NRU and PNGC?*

A. We have the following recommendations which are described in the testimony that follows.

- Structure the demand charge based on the direction given in the TRM (which will have the effect of reducing the demand charge in the Initial Proposal);
- Ensure that the load forecasts for FY 2012 and 2013 are as accurate as possible, after taking into account the effect of forecast conservation;
- Ensure that any new cost line items added to the Non-Slice rate are justified and consistent with the TRM;

- Properly credit unused Green Energy Premiums (GEPs) to the preference customers who paid for these GEPs by including the revenues in the Tier 1 rate, and charging the Variable Energy Resource Balancing Service (VERBS) rate the true costs those customers cause Power Services to incur;
- Reduce the effect of any cost recovery adjustment clause that could occur in FY 2012 and 2013 by reducing Agency costs prior to or instead of triggering the Cost Recovery Adjustment Clause (CRAC);
- Establish a process whereby the secondary revenue risk issue is addressed before the next rate case;
- Ensure that the General Rate Schedule Provisions are written properly;
- Price service to the Direct Service Industries using sound business principles and cost causation, as addressed in NRU's and PNGC's Joint testimony with PPC; BP-12-E-JP04; and
- Properly price generation input service to variable generation, which includes capturing and allocating costs associated with integrating variable generation to the VERBS rate.

The Demand Charge

Q. What is the purpose of this section of your testimony?

A. To make recommendations regarding the form and calculation of the demand charge proposed by BPA in this proceeding.

Q. Please describe BPA's proposed demand charge.

A. BPA proposes a demand charge that averages $9.57/ kW/month. This represents BPA's definition of what it believes are the fixed costs of a General Electric LMS 100 single cycle combustion turbine (SCCT) as derived from two different sources. This average demand charge is shaped over the year using the shape of HLH energy prices. BP-12-E-BPA-18 p. 18 - 23.

Q. What are the components of the demand charge?

A. BPA's proposed demand charge is made up of the following components. *See* BPA response to data request TA-BPA-7.

- $5.68/kW/month debt service
- $1.50/kW/month fixed O&M
- $0.21/kW/month Insurance
- <u>$2.19/kW/month</u> Fixed fuel
- $9.57/kW/month Total

Q. What objections do you have to this demand charge formulation?

A. We have two objections. First, the inclusion of insurance and fixed fuel costs in the demand charge is not mentioned anywhere in the Tiered Rate Methodology and should not be included here. Second, BPA is picking and choosing sources for its fixed O&M cost and should stay with one source, the Northwest Power and Conservation Council's Sixth Power Plan, for the data used in the demand charge calculation.

Q. Why do you object to the inclusion of insurance and fixed fuel costs in the demand charge?

A. The TRM says the following about the costs to be included in the demand charge: "*BPA will base the Demand Rate on the annual fixed costs (capital and O&M) of the marginal capacity resource as determined in each 7(i) Process."* Tiered Rate Methodology, p. 72, lines 19 - 20.

The cost items "fixed fuel cost" and "insurance" are not mentioned in the TRM as fixed costs that should be included in the demand charge. We are concerned that the tendency to go beyond the text of the TRM and find new costs based on the definition of the individual performing the analysis will lead to instability over time. In a number of the documents we have researched the definition of fixed costs varies significantly. When the TRM was written, we described those costs we saw as fixed at that time. At the very least the broader definition of fixed costs being proposed here in this rate proceeding should have gone through the Unanticipated Consequence process described in Section 12 of the TRM. On that basis the insurance and fixed fuel should be removed from the demand charge.

Q. What is BPA's proposal with regard to fixed O&M component of the demand charge?

A. While BPA staff took most of its cost data from the Northwest Power and Conservation Council's Sixth Power Plan, they decided to use the cost of fixed O&M from a California Energy Commission document. California Energy Commission, "Comparative Costs of California Central Station Electricity Generation", p. 57 (January 2010). We believe that when one data source is chosen that source should be adhered to unless that source is incomplete or in error. The Sixth Power Plan has been thoroughly vetted in the region and is the document of merit for this type of analysis.

Q. How does the Council define fixed O&M costs?

A. In the Sixth Power Plan the Council defines fixed O&M costs to include "*operating and routine maintenance labor, maintenance materials, routine contract services, and administrative and general costs. Insurance and property taxes are excluded. The cost of fixed O&M is assumed to escalate in real terms with the cost of construction*". Northwest Power and Conservation Council, *Sixth Northwest Conservation and Electric Power Plan*, Appendix I: Generating Resources, p. 80 (February 2010).

Q. What cost does the Council assign to Fixed O&M?

A. For the LMS 100 reference plant the Council assigns a value of $8.00 per kW per year. In 2012/2013 dollars and using BPA's inflation rate this value is $9.41 per kW per year. *Id.*

Q. Is the Council's cost for fixed O&M consistent with other sources?

A. Yes, we have researched a number of sources that estimate the fixed O&M costs of an LMS 100 SCCT. The Council's findings are consistent with these.

Q. Please give us some examples.

A. For example in the recently released National Economic Research Associates (NERA) Independent Study to Establish Parameters of the ICAP Demand Curve for the New York Independent System Operator NERA provided an estimate of fixed O&M for an LMS 100. Using the Council's definition of Fixed O&M the fixed O&M costs in this report ranged from $8.30 to $8.60 dollars per kW per year in 2010 dollars for the LMS 100, see page 98. http://www.nyiso.com/public/webdocs/documents/regulatory/filings/2010/12/NYISO_DCR_Filing_12_03_10.pdf

The Department of Energy, U.S. Energy Administration in its Assumption to the U.S. Energy Outlook of 2010 uses a value of $10.77 per kW per year for the cost of fixed O&M for an advanced SCCT. http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf#page=3

Q. Are you familiar with the California Energy Commission (CEC) report that was cited by BPA staff?

A. Yes.

Q. Do you have any observations about this report?

A. Yes. This report uses a definition of fixed O&M that is quite broad and tends to include costs that may not be appropriate for the purposes of establishing the demand charge in this proceeding. As stated there: *"Conceptually, fixed O&M comprises those costs that occur* *regardless of how much the plant operates. The costs included in this category are not always consistent from one assessment to the other but always include labor and the associated overhead costs. Other costs that are not consistently included are equipment (and leasing of equipment), regulatory filings, and miscellaneous direct costs. The Energy Commission staff uses the latter convention that includes these other costs".* California Energy Commission, "Comparative Costs of California Central Station Electricity Generation", p. 57.

Q. What is the range of fixed O&M costs in the CEC report?

A. These costs range from a low of $6.27 per kW year to an average cost of $16.33 per kW year. *Id*. at Appendix C: Gas-Fired Plants Technology Data, at p. 32. There is a high cost case cited with significantly higher fixed O&M costs but the assumptions used in the high case are not relevant to the unit being proposed for the BPA demand charge. The Council's fixed O&M cost of $9.41 per kW per year is well within this range.

Q. What is your recommendation with regard to the development of the demand charge?

A. BPA should base the demand charge on the assumptions that it has made with regard to the debt service costs of the LMS 100 based on the Council's Sixth Power Plan. BPA should also use the Council's Fixed O&M cost for the Sixth Power Plan and BPA should not add the cost of insurance and fixed fuel to the cost of the LMS 100.

Q. What would the level of the demand charge be based on these recommendations?

A. The demand charge would total $6.46 per kW per month. *See* Exhibit A. This would be comprised on $5.68 for debt service costs and $0.78 for fixed O&M. This approach directly abides by the direction given us in the TRM.

Load Forecasts

Q. What is the purpose of this portion of your testimony?

A. We urge BPA and the customers to work closely together to ensure that the load forecasts used in BPA's final proposal for case are as accurate as possible.

Q. Why is this of concern?

A. One of the uses of BPA's load forecast is to determine the amount of Balancing Augmentation power needed for the rate period. In BPA's initial proposal, the agency has included 95 aMW of Balancing Augmentation power based on consumer-owned utility load forecasts that were completed in March of 2010. *See* data response to WM-BPA-1. Perhaps more important, to the extent that BPA forecasts a need to purchase power to meet this load, these costs are added to the Non-Slice rate as a Balancing Augmentation cost. If the forecasts used are high and this power is not needed, then rates are higher than they would otherwise need to be for the Non-Slice customers. The additional funds that are recovered above actual costs simply go into BPA's financial reserves.

Given the state of the regional economy in 2010 we are concerned that the load forecast completed in March 2010 may not reflect what would currently be the best forecast for 2012 and 2013. In March 2010, there was optimism that regional recovery from the recession would be occurring in that year or early 2011. For rural utilities, economic recovery in the near term does not seem to be the case. Recovery and load growth are now considered to be further off.

Q. What do you propose be done?

A. We understand that BPA is working on new load and conservation forecasts for each consumer owned utility. The results of that forecasting effort will be used in the final rate proposal. We urge BPA in cooperation with its customers to work closely together on these forecasts to make them as accurate as possible. Then BPA should apply those results in the final rates proposal for 2012 and 2013. We are hopeful that such an application will reduce the balancing augmentation needed and the cost included in the rates.

BPA Should Allocate Power Services' Share of Wind Integration Team (WIT) costs to the Variable Energy Resource Balancing Service (VERBS) rate.

Q. *What is BPA's proposal with regard to recovery of Power Services share of the Wind Integration Team costs?*

A. As described in the testimony of Homenick, et al., *"... unspent Green Energy Premium (GEP) revenues earned during the WP-07 and WP-10 rate periods will offset Power Service's share of Wind Integration Team (WIT) expenses*". BP-12-E-BPA-13, p. 3-4, lines 22-23.

Q. *What are Green Energy Premiums?*

A. Green Energy Premiums are revenues from the sale of Renewable Energy Certificates and Environmental Attributes associated with the sale of environmentally preferred power and alternative renewable energy to BPA's power customers. *See* Integrated Program Review (IPR), Renewable Follow-up Session, p. 2 (June 10, 2010).

Q. *How were these revenues generated?*

A. These revenues are from unspent revenues from these sales from 2007 to 2011. As stated in BPA's testimony: "*Throughout the last decade, BPA has charged a premium for requirements power products provided by renewable resources. These requirements power products, called "Environmentally Preferred Power," included an additional charge reflecting the value of the environmental attributes associated with renewable generation. This additional charge is referred to as the Green Energy Premium (GEP)*". BP-12-E-BPA-23, p. 47-48.

Q. *How will these types of revenues be treated after FY 2011?*

A. After FY 2011, revenues from the sale of GEPs will be credited to the Composite cost pool and reduce the costs of BPA's PF customers. BP-12-E-BPA-11, p. 18, lines 13-1.

Q. What is the amount of these revenues?

A. These revenues total $6.3 million over FY 2012/2013. Homenick, et al. BP-12-E-BPA-13, p. 4, line 8.

Q. How is BPA proposing to fund Transmission Services' share of the Wind Integration Team's cost?

A. Transmission Services' portion of the Wind Integration Team budget ($4.2 million per year) is funded through the VERBS rate and charged to generators because funding Transmission Services' share of the WIT team with GEP would "*result in funding transmission costs with power revenues*". BP-12-E-BPA-23, p. 48, line 14.

Q. What is your assessment of BPA's assertion that the decision to devote Green Energy Premiums to fund Power Services share of WIT expenses was an IPR decision and not up for discussion in the rate case?

A. While BPA may have made this statement in both IPR and the rate case, we object to this practice. The allocation of costs and revenue credits to price different products has always been a rate case issue. For example, revenue credits for secondary revenues and load shaping revenues are a credit to the Non-Slice rate. The calculation and allocation of these credits to cost pools are rate case topics. To begin to carve out particular cost and revenue credit allocation practices as IPR issues not for discussion in the rate case is unacceptable.

Q. Has BPA allocated these revenue credits properly?

A. No. As noted above, these revenues were derived from Power Services' sales of power to its preference customers. These Green Energy Premiums should redound to the benefit of those customers. Also as noted above, BPA notes this as its established practice for these revenues after FY 2011. Starting in 2012, these revenues credits will be credited to the Composite Rate Pool and reduce the costs of its Slice and Non Slice customers.

Q. How should the costs of Power Services' share of the WIT costs be collected?

A. Just as Transmission Services' costs are being allocated to the VERBS rate, Power Services' costs should be allocated to the VERBS rate. As noted in the BPA testimony on this topic: "*Employees funded by the PS share of the WIT will work chiefly on the Wind Forecasting Initiative, including development of state awareness tools."* BP-12-E-BPA-25, p. 19, lines 13 and 14. Consistent with the principle of cost causation, the customers that take generation input services from BPA are imposing these costs on BPA. These costs would not have been incurred but for the presence of large amounts of highly variable and intermittent generation, namely wind, in BPA's balancing authority area. Therefore the resources that are using the VERBS rate should be responsible for paying these costs.

New Costs in the Non Slice Cost Pool

Q. What is the purpose of this section of your testimony?

A. This testimony asks BPA to do a better job of alerting the customers to new costs that are assigned to Cost Pools prior to the rate case and asks BPA to ensure that these costs are justified.

Q. Could you describe these new costs?

A. Yes, in the Initial Proposal we were surprised to see three significant new costs assigned to the Non-Slice Cost Pool. These were the Balancing Augmentation, Transmission Losses and Unused RHWM line item additions to the Non–Slice Cost pool. BP-12-E-BPA-01A, Table 2.5.5.2, p. 81. Altogether they total about $69 million per year and are an increase to the Non-Slice cost pool.

Q. *Are these new costs on the Non-Slice Cost Pool table in the TRM of September 2009?*

A. No they are not.

Q. *Why is this troubling?*

A. The appearance of these new costs is troubling because we first learned of these costs with the publication of the Initial Proposal. They are very significant, and were quite challenging to explain and understand. We are still not certain that all of these costs are appropriate and we are hopeful that they can be mitigated. These issues should have been dealt with prior to the Initial Proposal. Customers should have had the opportunity to discuss these new costs and their inclusion in the rate proceeding with BPA before the rate proceeding commenced.

Risk Mitigation

Q. *What is the purpose of this section of your testimony?*

A. Our testimony provides recommendations regarding BPA's risk mitigation strategy For FY 2012 and 2013.

Q. *What is BPA proposing with regard to risk mitigation for the upcoming rate period?*

A. BPA's risk mitigation proposal for FY 2012 and 2013 has a number of aspects. First, BPA has two sources of funds for liquidity purposes: $450 million from the U.S. Treasury Facility and $150 million in contributions to its financial reserves by Transmission Services. BP-12-E-BPA-15, p. 48. Second, BPA relies heavily on a cost recovery adjustment clause that could trigger on October 1, 2011 to collect up to $300 million in FY 2012. The same CRAC structure would be in place for FY 2013. Funds as a result of the CRAC triggering would be collected dollar for dollar up to $100 million and 50 cents on the dollar up to the $300 million cap. *Id.* at p. 54. To the extent that BPA uses up the financial reserves contributed by Power

Services, it would have to rely on either the Treasury Facility or financial reserves contributed by Transmission Services to meet its expenses. The CRACs described above are for the purpose of replenishing these sources of funds. *Id*. at p. 52.

Q. What is the notification process for triggering the CRAC?

A. As described in the GRSPs BPA calculates the amount of accumulated net revenues in July 2011 for use in calculating the CRAC for FY 2012. BP-12-E-BPA-09, p. 35-36. The calculation for FY 2013 is done in September 2012. If the forecast of Accumulated Net Revenues (ANR) is below the trigger point in each year by more than $5 million, BPA notifies the customers and provides the relevant data. A workshop is then held and the Administrator has the discretion not to trigger the CRAC if BPA's financial standards are met. If the standards are not met, the CRAC goes into effect for the next Fiscal Year. BP-12-E-BPA-09, p. 35.

Q. Are you recommending any changes to Bonneville's approach?

A. Yes, we believe two important changes are necessary. First, Bonneville should engage in additional cost cutting before implementing any CRAC. Second, we believe that if there is a need for a CRAC after the additional cost cutting has been accomplished, that CRAC should not be implemented until the start of FY2013.

Q. Why should Bonneville engage in additional cost-cutting prior to implementing a CRAC?

A. We have heard very clearly from the members of NRU, WMG&T and PNGC that if BPA is considering triggering a CRAC it needs to look first at its cost levels and seriously examine making reductions of expense items and debt before triggering any CRAC. We understand that a sound business case can be made for much of BPA's internal spending and the financial support of other entities that BPA funds. However, our member utilities and the institutions they serve are strapped for funds. School districts, state and local governments, etc., are making very hard choices to stay within available funding so that their constituents can make ends meet. When faced with difficult financial situations, BPA needs to look at cost reductions within rate periods as a potential solution.

Q. Has BPA made accommodations for this sort of cost review process prior to triggering any CRAC?

A. Yes. As the Administrator stated in his Integrated Program Review Final Close-Out Letter of October 27, 2010, " …prior to submitting final rate proposals, we will assess any new or updated information and will determine if any cost changes are appropriate and whether an abbreviated public review process is warranted." This language was added in response to customers' requests that a significant rate increase remaining after the IPR and ratemaking come together be addressed through a second look at BPA's cost levels. We strongly believe that a public process is warranted in advance of triggering a CRAC. As signatories to Regional Dialogue contracts for cost based rates, we encourage forums where the Agency and customers can interact and debate the best path forward applying sound business practices for both the Agency and its customers. Such processes need take little time and are a path to better understanding, which then makes the application of a CRAC, if necessary, easier to deal with and explain.

Q. What should be the timing of such a review?

A. This abbreviated public process could occur in August 2011 and be completed prior to any CRAC being implemented in FY 2012. For a CRAC triggering in FY 2013, similar timing could be used.

Q. Why is such an added cost review process warranted?

A. We continue to be concerned about a perceived lack of cohesion between the IPR process and the ratemaking process. Our memberships are facing significant rate increases as a result of two factors: 1) the implementation of the TRM and 2) the overall increases in BPA's costs. While the average rate increase for the Non-Slice customers is 9.2% (and number of the customers that we represent are facing rate increases of more than 15% based on BPA's forecasts of loads. BP-12-E-BPA-11, p. 52; http://www.bpa.gov/corporate/ratecase/2012/docs/WedRateImpact_12_8_2010.pdf. A CRAC on top of this, if CRAC were to trigger for $100 million, would add 7% to this rate increase. If a CRAC is forecast to be needed, by taking a second look at its costs we can provide better assurance to customers that BPA has established the link between ratemaking and cost determination that customers are seeking.

Q. Do you have a recommendation as to how large these cost reductions should be before Bonneville implements a CRAC?

A. Yes, we believe the agency should absorb $33 million in cost reductions and deferrals – approximately 1.5 percent on the Non-Slice revenue requirement – before implementing a CRAC. That level would show a true commitment to keeping rates as low as possible consistent with sound business principles.

Q. If a CRAC is still necessary after the $33 million in additional cost reductions, why should Bonneville implement that CRAC in FY2013?

A. We do need to consider whether an immediate financial problem for Power Services in one fiscal year that can be temporarily covered by borrowing should be repaid in whole or in part during the next fiscal year, or alternatively spread over a longer period of time. We understand the mechanics of the BPA proposal, but the BPA proposal is just one of many possible approaches.

If Bonneville wanted to avoid having a CRAC trigger the same day as an already-significant rate increase and rate design change, one alternative would be to collect the CRAC with the same parameters proposed by Bonneville but beginning October 1, 2012. To the degree that Bonneville needs to collect more than the ceiling of $300 million, any remaining amount could go into the next rate period. This approach would allow the economy to recover during FY2012 without the burden of a CRAC triggering on the same day as another Bonneville rate increase, which for some Bonneville customers could exceed 40 percent. There are a number of variations on this proposal, but if a CRAC is necessary after additional cost reductions, we support implementing it in FY2013.

Secondary Revenue Risk

Q. Have you reviewed the risk and risk mitigation information in BPA's Initial Proposal?

A. Yes, we have and our testimony above addresses aspects of Risk mitigation, such as the timing for the CRAC and our recommended solution. This section addresses issues that BPA raised about certain elements of secondary revenue risk and whether BPA's current models handle these risks well.

Q. Do you have an example?

A. Yes. For this case BPA is calculating the credit for net secondary revenue applied to the Non-Slice rate based on median value of the net revenue distribution. BP-12-E-BPA-11, p. 23.

Q. Is this different than previous cases?

A. Yes it is. In the past BPA calculated the credit for net secondary revenue on an expected value basis of the net revenue distribution. As we understand it, this results in a $31 million reduction in the amount of net secondary revenue credit to the Non-Slice rates.

Q. Has BPA provided their reasons for this change?

A. BPA expresses the view that they now consider using the expected value more reasonable for a long-term perspective and the median value to be more appropriate for rate setting.

Q. Do you agree with this policy change?

A. Not completely. We believe that BPA made this change without adequate consideration and discussion with the customers that are affected. While it appears that the policy direction that was provided to the BPA rate staff is reasonable, we would like to better understand both the long-term and short-term implication of this policy change on the Non-Slice rate, BPA's reserves, risk and risk mitigation, and any other implications in BPA rate making. *Id*.

Q. How do you see this issue being resolved for the future?

A. We suggest that BPA work with customers to further the understanding of this policy change through additional workshops and informational sessions. The goal would be to have a resolution of this issue so that it could be entered into the next rate proceeding that will set rates for FY 2014/2015.

The General Rate Schedule Provisions (GRSPs)

Q. Do you have any concerns about the General Rate Schedule Provisions?

A. Yes, while it is obvious that BPA staff spent considerable effort in trying to ensure that the GRSPs are consistent with the recommendations in BP-12 and the Tiered Rate Methodology and the Unanticipated Consequence process we have found a number of areas where the language being used in the GRSPs differs from both the TRM and the Unanticipated Consequence language. Considerable effort was made in the TRM and unanticipated consequence discussions to carefully craft language that carried out the intent of parties. GRSPs are important in that they tend to take on a life of their own and are the documents that govern the business relationship between BPA and its customers.

Q. Could you give us some examples?

A. This is by no means an inclusive list, but for example the Unintended Consequence provision defines the *applicable LDD* as the "LDD percentage to be applied to a customer's bill." BP-12-E-BPA-11, Attachment 1, p. 3. The GRSPs defines that same term the *applicable LDD* as "the discount percentage to be applied to the Tier 1 charges on a Customer's bill." BP-12-E-BPA-09, p. 50. Another example would be where the Load Shaping Charge in Section 2.1.3 of the GRSPs differ from the intent of the TRM in Section 5.2.2. BP-12-E-BPA-09, p. 6; Tiered Rate Methodology, p. 60. In the GRSPs 24 values are given whereas in the TRM 48 values are called for. A further example would be definitions of System shaped load in the GRSPs compared to Section 5.2.1.1 of the TRM. *See* BP-12-E-BPA-09, p. 7; Tiered Rate Methodology, p. 59.

Q. Are these language differences material?

A. They may or may not be. It is difficult to understand the implications of these variations in wording absent a discussion with BPA staff.

Q. What is your solution to this problem?

A. We are concerned that given the press of the rate case schedule sufficient attention has not been paid to the GRSPs. We request that sufficient time be given to a discussion of the GRSPs in a workshop setting with the participation of BPA and the customers.

Generation Inputs Policy

Q. Have you reviewed BPA's Initial Proposal with an eye to the risks that increasing amounts of wind generation is imposing on the system and the effect it is having on market prices?

A. Yes, we have. We are very concerned about the increasing amount of wind generation and the risks it imposes on BPA's need to provide reliable cost-based power to its preference customers. We are not confident that the Variable Energy Balancing Services (VERBs) rate is fully recovering the costs that the integration of non-federal variable generation imposes on the federal system.

Our concern is heightened when we turn to the effect that increasing amounts of wind is having on market price. This concern is sprinkled throughout the BPA testimony, just two examples suffice to show the uncertainty that has arisen over time as the wind fleet has grown:

> "One concern is over the possibility that the highly variable nature of wind generation makes it possible that total regional generation could spike rapidly and a sudden surplus of generation compared to load could cause market prices to fall, even to the point that market prices could be negative". BP-12-E-BPA-11, p. 23.

> "Given the reduction in loads throughout the WECC and the addition of thermal generating plants and significant levels of wind generation, we are still concerned over the market dynamics that may occur and that are difficult to model. This concern is supported by some of the past spring runoff periods, when daily prices have been very low, even negative at times". BP-12-E-BPA-14 p. 16.

Q. Why is this issue important to your memberships?

A. This issue is critical to our memberships. To the extent services are improperly priced we bear the consequences through cost shifts. To the extent that market prices are affected by variable generation and lower market prices we bear the consequences through lower secondary revenues, which are a credit to the Non-Slice rate.

Q. Have you reviewed the rate case parties' approaches to cost allocation and cost causation?

A. Yes, we have. Other preference customers have made rate level and rate design proposals for VERBS that approach a more equitable cost allocation. We support BPA's consideration of these proposals.

However, we are concerned that these approaches do not get to the fundamental issue of the effect of variable generation on market prices. Further work needs to be done on the effect of variable generation on market prices.

Q. Do you support BPA's initiatives with regard to negative pricing?

A. Yes, we do. BPA needs to take strong action in these areas.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit A
of
BPA-12-E-JP02-01

Start Year of Operation (FY)	2012	
Cost of Debt	4.71%	/3
Inflation Rate	2.52%	
Debt Finance Period (years)	30	/1
Plant Lifecycle (years)	30	/1
Heat Rate MMBtu/kWh	0.00877	/1
All-in Nominal Capital Cost LMS100 $/kW	$ 1,083.00	/1
Fixed O&M $/kW/yr	$ 9.29	/2

Calendar Year	Chained GDP IPD	
2004	96.77	
2005	100.00	
2006	103.26	
2007	106.30	
2008	108.62	
2009	109.62	
	102.52%	5-year Ave.

Chained GDP IPD from BEA -- Table 1.1.9. Implicit Price Deflators for Gross Domestic Product - Last Revised August 27, 2010

Month	Load Shaping Rate HLH $/MWh	Demand Shaping Factor	Monthly Demand Rate $/kW/mo
Oct	43.97	8.14%	$ 6.31
Nov	44.48	8.24%	$ 6.39
Dec	47.63	8.82%	$ 6.84
Jan	45.78	8.48%	$ 6.58
Feb	45.87	8.49%	$ 6.58
Mar	44.01	8.15%	$ 6.32
Apr	40.28	7.46%	$ 5.78
May	38.33	7.10%	$ 5.51
Jun	39.50	7.31%	$ 5.67
Jul	49.65	9.19%	$ 7.13
Aug	51.70	9.57%	$ 7.42
Sep	48.80	9.04%	$ 7.01
		Average $/kW/mo	$ 6.46

End of Fiscal Year	Midyear Assessed Value	Debt Payment	Fixed O&M	Cash Expense Each Year
2012	$ 1,064.95	$68.14	$ 9.29	$77.43
2013	$ 1,028.85	$68.14	$ 9.52	$77.66
			Rate Period Average Expense $/kW/year	$77.54

/1 Source NWPCC Microfin Model with 100% PUD ownership with plant in service 2012
/2 Nothwest Power and Conservation Council, 6th Power Plan, Appendix I, page I-80 with 2.52% inflation 2006 to 2012/2013

/3 Source BPA FY 2010 Third-Party Tax-Exempt Borrowing Rate Forecast 30-year