2010 Wholesale Power Rate Case Initial Proposal

DIRECT TESTIMONY

MANAGING THE RATE INCREASE

April 2009

WP-10-E-BPA-33

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REBUTTAL TESTIMONY of

BYRNE LOVELL, ELIZABETH A. EVANS,

VALERIE A. LEFLER and RAYMOND D. BLIVEN

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SUBJECT: MANAGING THE RATE INCREASE

Section 1: Purpose and Overview

Q. Please state your names and qualifications.

A. My name is Byrne Lovell, and my qualifications are contained in WP-10-Q-BPA-38.

A. My name is Elizabeth A. Evans, and my qualifications are contained in WP-10-Q-BPA-17.

A. My name is Valerie A. Lefler, and my qualifications are contained in WP-10-Q-BPA-36.

A. My name is Raymond D. Bliven, and my qualifications are contained in WP-10-Q-BPA-06.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to explain changes in BPA's business environment subsequent to the publication of the WP-10 Initial Proposal, to describe analyses performed by Staff, and, finally, to describe Staff's proposed set of risk tools that could be used when calculating rates for the WP-10 Final Proposal in order to mitigate a possible large rate increase.

Q. How is your testimony organized?

A. Section 1 is this overview. Section 2 describes the circumstances that have prompted us to present this additional testimony. Section 3 describes the available tools that can counteract an otherwise large rate increase. Section 4 describes the analysis that Staff has performed to gain a better understanding of the interactions of various assumptions on the rate level and on the effectiveness of risk mitigation tools. Finally, Section 5 describes Staff's recommendation regarding the use of risk mitigation tools.

Section 2: Changing Conditions Since the Initial Proposal

Q. Why are you filing this additional direct testimony?

A. For several reasons, both BPA staff and rate case parties had become concerned that, by the time BPA published its WP-10 Initial Proposal, circumstances affecting the proposed rate level had changed considerably compared to the assumptions in its Initial Proposal. As a result of these changes, Staff considered it important to present the issues to the parties and discuss what appeared to be a possible rate increase of approximately 15 to 20 percent.

Q. Would you recount the types of changes have occurred since publication of the Initial Proposal that are causing this concern?

A. There are generally three areas of change. First, the local, national and global economies have all experienced rapid declines – the extent of which started to be clear only when BPA was completing its studies for the WP-10 Initial Proposal. Second, largely resulting from the economic downturn, actual FY 2009 natural gas prices and forecasts of natural gas prices for the remainder of FY 2009, as well as FY 2009-2011 have declined steadily since the rate case forecasts were developed. Third, forecasts of Power Service's FY 2009 modified net revenue (MNR) have been declining sharply since the data were incorporated into the initial proposal. Absent action, these factors could lead to a significantly greater rate increase than initially proposed. We recognize that given the current economic conditions, both regionally and nationally, such a large rate increase is not appropriate.

Q. What other impacts has this economic downturn had on the assumptions in the Initial Proposal?

A. Staff believes that the economic downturn has had a dampening effect on BPA's loads, although the revised forecasts are not yet completed. Even though the analysis is not complete, staff believes that it is important to consider these changes when formulating its approach to limiting the potential rate increase. These updated load numbers indicate that BPA's public utility loads will likely be below the forecasts used in the Initial Proposal. Preliminary results indicate that the reduction for Load Following customers will be approximately 220 aMWs in FY 2010 and 240 aMWs in FY 2011. In addition, the load estimate for Block and Slice customers declined approximately 200 aMWs in FY 2010 and 160 aMWs in FY 2011. The lower loads are due primarily to errors in the calculation of loads for a few customers as well as the economic downturn.

Q. How will the reduction in load affect the rate calculation?

A. In the Initial Proposal, Staff forecast that its loads would exceed the firm capability of the FCRPS. As a result, augmentation purchases were forecast to bring the system into load/resource balance. In the Initial Proposal, the forecast of augmentation of the system was 372 aMWs in FY 2010 and 599 aMWs in FY 2011. Load Resource Study, WP-10-E-BPA-01, at 23. With the forecast of lower loads, the amount of augmentation purchases will be reduced accordingly. The reduction in augmentation purchases reduces BPA's power revenue requirement and in turn lowers the rates. How much the rates could be reduced due to a lower public utility load forecast will depend in large part on the assumptions regarding future market prices and the final load forecast.

Q. Does the load loss for Load Following, Block and Slice customers impact BPA the same way?

A. No. Because BPA meets all incremental load of Load Following customers, any reduction of load for these customers will translate directly into a loss of sales for BPA. With Block and Slice customers, it is less likely that BPA would see any reduction of sales as a result of the load loss by these customers. Most Block and Slice customers have their own resources and meet their incremental load on their own. When they experience a loss of load, these customers have the right to remove their own resources rather than reduce the amount of energy they purchase from BPA. Therefore, it is unlikely, absent a situation where the load loss exceeds a customer's ability to remove resources, that BPA would see any reduction in its sales. As a consequence, BPA staff assumed only a loss of the Load Following sales for purposes of the scenario analysis described in section 4.

Q. *What changes have occurred in gas and electricity price forecasts since the Initial Proposal?*

A. As explained in more detail in the Petty, *et al.*, WP-10-E-BPA-13, natural gas prices are the principal driver for western U.S. electricity prices. Gas prices have fallen steadily since last fall. Current NYMEX prices for FY 2010-2011 are around $6/MMBtu, compared to the approximately $7.25/MMBtu assumed in the Initial Proposal. While staff has not completed its final market price forecast for the rate period, we do not anticipate that prices will return to the level of prices forecast in the Initial Proposal. Lower gas and electricity prices will have several effects – both positive and negative – on power rates.

Q. *What impact do declining gas price forecasts have on rates?*

A. The forecast of natural gas prices affects many aspects of the development of BPA's rates. The immediate impact is that forecasts of market prices for electricity in the region are highly affected by forecasts of gas prices. In turn, electricity price forecasts affect the Average System Costs (ASCs) of utilities participating in the Residential Exchange Program, the cost of augmentation and balancing purchases, the size of the net secondary revenue credit, the variable cost of providing power reserves, and the magnitude of the financial risk Power faces as a result of the natural variability of streamflows.

Q. *Can you simplify this description?*

A. Yes. The largest two effects, which work in opposite directions, are as follows. When gas price forecasts are high, and therefore forecasts of electricity prices are also high, the forecast of Power's net secondary revenue is also high, which has a downward effect on BPA's rates (except for Slice rates). At the same time, when gas and electricity price forecasts are high, the financial impact of hydro uncertainty is magnified, and Power needs to have more risk mitigation. The main risk mitigations Power uses for mitigating financial risk are financial reserves and the Cost Recovery Adjustment Clause (CRAC), so these tools have to be made more powerful as gas prices increase, producing upward pressure on BPA's non-Slice rates. When gas prices are lower, the opposite effects occur; the net secondary revenue is lower, driving rates higher, and power purchases and financial risk are lower, reducing upward pressure on rates.

Q. *Which effect has been stronger with lower gas prices in FY 2010-2011, the upward rate pressure from the lower credit for net secondary revenue, or the downward rate pressure from lower power purchase costs and reduced risk?*

A. Unfortunately, that question is not as simple as it sounds. The relationship between gas forecasts and BPA's rates, taking into account all of the impacts, is not a linear relationship. We can model (*i.e.*, simulate) a particular scenario, or a different one, but we cannot describe the relationship analytically (*i.e.*, algebraically). The impact of lower risk depends on the total effectiveness of the risk mitigation tools Power uses in calculating power rates In addition, we have been trying to find more tools as well as increase their effectiveness.

Q. *What has been driving the change in FY 2009 Power modified net revenues?*

A. Two factors, lower prices and less supply, have led to a reduction in Power's modified net revenues (MNR) for FY 2009 relative to the Initial Proposal. Current estimates of MNR indicate that FY 2009 financial results could end up about $150 to $250 million lower than assumed in the Initial Proposal. The largest driver is streamflows in the Columbia River basin. Forecasts of the streamflow for FY 2009 are considerably lower than they were at the beginning of the fiscal year. According to the Northwest River Forecast Center, forecasts of the January through July runoff are now ranging between 80-85 percent of average streamflows. This lower inventory, combined with much lower-than-forecast market prices for electricity, has led to a dramatic reduction in the expected level of net secondary revenues for FY 2009. As a result of this reduction in net secondary revenues, starting reserves for the WP-10 rate period will likely be lower than previously expected, which puts upward pressure on the rate level. Financial results in 2009 affect the level of financial reserves that Power can rely on to meet BPA's 95 percent Treasury Payment Probability (TPP) standard for the two-year FY 2010-2011 rate period. The expected erosion of reserves due to low net secondary revenues for FY 2009 makes risk mitigation more expensive for the FY 2010-2011 rate period. To address this, either a significant amount of Planned Net Revenues for Risk (PNRR) would need to be added to the non-Slice PF, IP, and PF Exchange rates, or the Cost Recovery Adjustment Clause (CRAC) mechanism would need to be strengthened, meaning that the probability and magnitude of one-time increases in these rates would be much higher.

Q. What do all these changes mean in terms of an impact on rates?

A. All else being equal, and absent any actions to mitigate the impacts, the rate increase for FY 2010-2011 could be 15-20 percent above FY 2009 rates. However, given the economic situation, this is not an acceptable outcome.

BPA Staff and rate case parties have been discussing the options to limit the rate increase to something that is manageable for the region in these dire economic times. The balance of this testimony describes the possible approaches to mitigating this potential rate increase.

Section 3: Potential Tools

Q. What has BPA done in response to these changed factors?

A. Since BPA filed its Initial Proposal, BPA staff met in settlement discussions with rate case parties to discuss a set of tools to mitigate the potential rate increase. During these discussions, Staff and parties began to develop a clearer picture of what BPA's final proposal might be, given the changes in some of the base assumptions. This testimony lays out the tools that Staff developed and discussed with rate case parties that we believe are the most effective, under different sets of circumstances, to address the changed conditions.

Q. How has the downturn in the world's economies affected BPA's rate case?

A. There have been many impacts. One impact has been that world and national demand for hydrocarbons has declined, and that is at least part of the reason for the afore-mentioned decline in gas price forecasts. A second is that the local economies in the service territories of our customer utilities have been hard hit, and our customers are more sensitive than ever to the impacts of possible BPA rate increases on their own rates and on the communities they serve. A third impact is that the swiftness of the development and spread of the economic crisis has made it more difficult than usual to forecast future developments that are relevant to the rate case with any confidence. One way this matters is that even if the last number crunching for the final proposal is only two months away, it is very hard to project now what our gas price forecast would be two months from now. Perhaps demand will storm back, nearly as fast as it crashed; perhaps the slump in demand will deepen – we can't know. That puts a premium on waiting as long as possible to put the finishing touches on the rate case gas forecast.

Q. Given this uncertainty, how did you develop this clearer understanding of BPA's final rates?

A. Staff developed a series of scenario analyses that considered three different gas prices for FY 2010-2011, two levels of cost reductions, and two amounts of additional liquidity. In addition, two different levels of FY2009 financial results were factored into this analysis.

Q. What three gas price levels did you include in your analysis?

A. To account for the uncertainty over future gas prices, Staff created two additional gas price forecasts. At the time BPA froze the assumptions in the Initial Proposal, the average price at Henry Hub for the two years was about $7.25/mmBTU; at Sumas, the average was about $6.80. In light of the changes in so many economic variables, both regionally and globally, BPA created two additional gas prices assumptions that are lower than the Initial Proposal. In this manner, we could see how these gas price assumptions would affect our rate proposal. The lower of the two has an average price at Henry Hub of about $4.00/mmBTU; at Sumas, the average was about $4.25. The higher of the two alternatives has average prices at Henry Hub of about $5.25/mmBTU; at Sumas, the price averages about $5.50. These are "what if" alternative forecasts – they are not indications that BPA thinks the gas price will be $5.25 or $4, they are just forecasts that we can use to demonstrate how differing gas prices could ripple through the complex workings of BPA's ratesetting.

Q. What did you learn from running these gas prices through your models?

A. We noticed that the level of the gas price dictates the nature of problem that we face and the steps necessary to try to keep rates low. To understand this better it will help to explain how BPA sets rates. BPA has three tests that rates must meet: first, rates need to be high enough to recover rate period costs on a cash basis; second, they need to high enough to recover rate-period costs on an accrual (*i.e.*, net revenue) basis; and third, they need to be high enough to meet BPA's TPP standard, given the risk mitigation tools included in the rates package. BPA conducts these tests in two parts. The revenue requirement describes the costs on both cash and accrual bases in sufficient detail that the Rates Analysis Model (RAM) can calculate rates that meet the two cost-recovery tests. Revenue Requirement Study, WP-10-E-BPA-02, at 28. We can call these rates the "pre-risk" rates. These rates do not yet include the cost, if any, of meeting the risk test, which is the TPP standard. After calculating the pre-risk rates, the rates are simulated in RiskMod, and the resulting net revenue games are then run through the ToolKit to measure the TPP. If the pre-risk rates do not meet the two-year 95 percent TPP standard, then additional risk mitigation is needed, either in the form of PNRR dollars or a more powerful CRAC mechanism. If PNRR is needed to reach the TPP standard, this “cost” is added into a revised revenue requirement, and new, post-risk rates are calculated. In a similar fashion, the impact of the operation of the CRAC on rates can be estimated by calculating the expected value over the 3,500 games BPA runs of the amounts of additional revenue the CRAC generates.

Q. How does the level of the gas price forecast affect rates?

A. With higher gas prices, the market price for electricity price is higher, and the expected value of net secondary revenues is also higher. These factors help reduce the level of the pre-risk rate . However, the higher prices of electricity also mean that each incremental MAf of streamflow is worth more money, and each decremental MAf of streamflow costs BPA more. As a result, BPA’s financial risk is higher with higher electricity prices, and more risk mitigation is needed. Conversely, under low gas prices, the credit for secondary revenue is smaller, so the pre-risk rates are higher. However, the financial risk is much smaller, so the cost of risk mitigation is lower also.

Q. Why does this matter?

A. It matters because the solutions needed for the basic problem – a potentially high rate increase – are directly affected by the level of the gas price forecast in the final rate studies. If BPA forecasts high gas prices, close to those in the Initial Proposal, we will have relatively low pre-risk rates but a higher cost of risk mitigation. Any solution to high rates due to the cost of risk protection depends upon finding new risk mitigation tools. On the other hand, if the gas price forecast is lower, the effectiveness of risk tools is limited because the primary problem is the pre-risk rate.

Q. What is the impact of the deterioration in FY 2009 financial results?

A. The deteriorating FY 2009 financial results directly impact the post-risk rates and do not materially affect the pre-risk rates. The level of financial reserves that Power can rely on for mitigating risk in the FY 2010-2011 rate period remains uncertain because much of FY 2009 still lies ahead of us.

In the Initial Proposal, the expected value of Power modified net revenue (MNR) over the 3,500 games was -$91 million. The forecast of FY 2009 MNR can change daily, but as noted above there has been a significant erosion of MNR since the Initial Proposal. This means that starting reserves for FY 2010-2011 are likely to be lower than assumed in the Initial Proposal. If rate period starting reserves end up lower than previously assumed, some other forms of risk mitigation have to replace the lost risk protection. BPA typically includes PNRR in its ratesetting to provide this needed risk mitigation, but adding PNRR increases the post-risk rates. However, if other forms of risk protection can be found then PNRR can be reduced or eliminated.

Q. Please describe these tools that can reduce the level of the potential rate increase.

A. There are two categories of other tools that can reduce the potential rate increase. There are cost tools and risk tools. Cost tools (i.e, cost reductions) reduce the level of costs that we include in the revenue requirement (prior to any risk mitigation costs). That is, they help reduce the pre-risk rate. They are not as effective in mitigating the impact of the poor FY 2009 financial results, because in the context of the FY 2010-2011 rates, that is a risk problem, and affects only the post-risk rates. Risk tools, on the other hand, have much more powerful impacts in high-gas price scenarios, and therefore, high-risk futures. There is a limit, however, to how much help risk tools can provide in a low-gas price future because PNRR and CRACs have less of an impact on the rates.

Q. What kinds of cost reductions have you been exploring?

A. BPA is currently holding the second round of the public process called the Integrated Program Review (IPR), referred to as IPR2, to re-visit program levels decided in an earlier phase of this public process (IPR). The Initial Proposal reflects proposed program levels determined in the original IPR that ran from May through November 2008. Given the current economic situation, BPA and its partner agencies are continuing to review their expense forecasts to look for additional opportunities for reductions.

In addition, FY 2009 cost forecasts have been reduced in several areas, including BPA internal operating costs, which will affect the forecast of ending FY 2009 cash reserves in the final rate proposal.

BPA intends to share draft program level decisions on April 24, hold a final IPR2 workshop on April 29, with a comment period that runs through May 1, after which BPA will make decisions, outside of this rate proceeding, on the forecast of program levels for FY 2010-2011. These program level decisions will be used in the Final Proposal.

Q. Are there other types of cost reductions that can affect the rate level?

A. Yes. Power rates reflect the cost of augmenting our existing resources to meet loads under critical water. This cost is not a subject of IPR2 but is determined in the ratesetting process. Given the high likelihood of lower load forecasts for the final proposal already discussed, combined with the likelihood of a lower gas price forecast, it is highly likely that augmentation costs will also be lower in the Final Proposal. The combination of these factors means fewer augmentation purchases at lower market prices. Together, these factors should bring down the augmentation cost that is included in rates.

Q. Are there other cost savings that may be realized in time for the Final Proposal that affect augmentation costs?

A. Yes. Energy Northwest (EN) may be able to develop a revised plan for the CGS outage in 2011 that includes refueling and the condenser replacement. If EN develops a revised plan that is sound enough to count on for rate case purposes, we can reflect that in the Final Proposal. While the financial impact of such a change varies with the gas price, the lower amount of augmentation needed to meet loads should reduce the rate level.

Q. Please describe what you mean by risk tools.

A. As previously stated, financial reserves are a primary risk tool BPA uses to mitigate financial risk. Financial reserves do not constitute a source of funding for BPA programs. In other words, they are not intended to take the place of current revenues to fund current expenses; rather, they supply liquidity. Liquidity is a temporary availability of cash or cash equivalents that allows you to meet some cash obligation, but that requires repayment. Liquidity is highly useful for mitigating the risk derived from highly variable secondary sales.

Q. Please explain.

A. Cash reserves are liquidity and not a source of funding because BPA relies on financial reserves to mitigate financial risk. If BPA uses reserves to pay bills, the next time BPA sets rates it will find that it has less liquidity for mitigating risk, and it will need to add PNRR to the revenue requirement to build reserves back up. BPA would then have to replenish the reserves it used to pay bills. Because BPA will need to replenish the reserves, they are a source of liquidity rather than a source of funding.

Q. Why is this characterization of financial reserves as a form of liquidity important?

A. The current problem posed by Power's FY 2009 financial reserves is one of a lack of liquidity. As a consequence, other sources of liquidity may be able to help mitigate the potential rate increase. And therefore Staff has focused on finding additional risk tools that are sources of new or additional liquidity.

Q. What are these potential sources of new or additional liquidity?

A. There are three tools here that we think are reasonable to consider other than PNRR. These are the Flexible PF Rate Program, the temporary availability of reserves attributed to Transmission, and an expansion of an agreement BPA has with the U.S. Treasury allowing for a short-term liquidity facility to pay for current expenses.

Q. Which of these tools appears to be the most promising?

A. An expansion of the Treasury liquidity facility appears to be the most effective. We already have an agreement in place with the Treasury that permits BPA to borrow up to $300 million for current expenses. The cash proceeds from the borrowing can be available to BPA in a matter of hours. Advances under the existing agreement would need to be repaid the earlier of two years after the original issue date or by October 3, 2012. BPA has been discussing with Treasury staff the possibility of having the total borrowing limit increased by an additional $450 million for a total of $750 million. Advances under an expanded agreement, if signed, would need to be repaid by the earlier of two years after the original issue date or by the end of April 2013. Potentially, we could treat this additional $450 million as available liquidity that could be used to support Power's TPP. Obtaining the increase in the Treasury liquidity facility would very probably allow BPA to remove all PNRR from the rates we calculate in the final proposal.

Q. Can you count on this tool now?

A. No – there are two significant limitations that keep BPA from relying upon it at this time. First, the agreement to expand the facility providing the additional $450 million has not been signed at this time. However, the responses so far from Treasury staff have been very encouraging and BPA is very hopeful that it can be approved by the end of April, 2009. Second, there are some potential limitations to BPA's use of an expanded facility that we have not yet had time to fully assess. These are mainly the limitations on BPA's total borrowing, either the limit on the total amount of outstanding BPA Federal debt (the "borrowing cap"), or the limit on the amount of new borrowing in a single fiscal year, given administrative and reporting requirements as a Federal agency. BPA is very hopeful that we will be able to create solutions to these limitations, and thus be able to rely on the full value of new liquidity provided by an expanded facility as soon as it is approved.

Q. *Are you considering the amount of the current facility, $300 million, as liquidity that can help compensate for the erosion in financial reserves caused by the low net secondary sales?*

A. No. So far in this testimony we have been talking about liquidity in terms of an annual amount of cash that is temporarily available to pay the Treasury at the end of each fiscal year. This form of liquidity must be replenished in subsequent years. Another equally important liquidity need is temporary within-year cash to pay expenses during the fiscal year. BPA believes it needs the entire $300 million of the current facility to provide within-year liquidity.

Q. *Does BPA usually set an amount of financial reserves aside for within-year use that BPA then considers to be unavailable for TPP risk?*

A. In prior rate cases BPA set aside an amount of financial reserves for within-year use that were unavailable for purposes of calculating the TPP. In the WP-10 Initial Proposal, BPA reduced liquidity reserves to zero and relied solely on the Treasury facility for within-year liquidity. This assumption is reflected in our ToolKit modeling by setting the deferral threshold to $0, meaning that the ToolKit records a deferral only if the financial reserves it tracks during a game go below $0. The ToolKit looks only at reserve levels at the end of fiscal years; it does not consider anything that can happen within a fiscal year. Now we are treating the $300 million of liquidity provided by the Treasury facility as dedicated to within-year needs, and we are treating financial reserves as if they are all available for end-of-year issues, that is, Treasury payment and TPP issues.

Q. What is the second potential source of additional liquidity?

A. The second source of additional liquidity is the Flexible PF Rate Program. We are treating this as "additional" liquidity because we did not assume in the Initial Proposal that the program would necessarily be around during FY 2010-2011. The program provides liquidity by requiring the prepayment of power bills for those firm power customers who participate in the program. The Flexible PF Rate Program has the potential to generate additional, temporary cash for BPA if it is needed. After three months, customers are repaid by having reduced power bills. This effectively results in a reduced cash flow from these customers to BPA as the liquidity is replenished. Due to the short time frame of this liquidity in comparison to financial reserves or the Treasury facility, BPA believes that it takes about $7 of this liquidity to be equivalent to $5 of reserves or of Treasury liquidity.

Q. How much additional liquidity do you think the Flexible PF Rate Program could provide?

A. Informal inquiries by BPA's account executives to their customers indicate that it is likely that at least $140 million of participation could be achieved, which BPA would translate into the equivalent of $100 million of liquidity provided by reserves or the Treasury note. However, more might be possible.

Q. What is the third possible source of additional liquidity?

A. The Bonneville Fund currently contains reserves available for risk that have been attributed to Transmission that are greater that the amount needed to meet Transmission's 95% TPP standard. The Administrator may determine that Power can rely on the Transmission reserves above the amount needed for TPP to support the Power TPP.

Q. How much liquidity is available from Transmission reserves?

A. The risk analysis from the TR-10 rate case initial proposal indicates that $100 to $110 million of reserves attributed to Transmission might be available, should the Administrator determine that this is appropriate.

Q. Are there any particular concerns with relying on Transmission reserves for Power's liquidity needs?

A. The use of Transmission reserves by Power for liquidity needs presents some unique problems. To illustrate, two scenarios are compared. In scenario 1, $200 million of need for more Power liquidity is met by relying on $200 million of Transmission reserves. In scenario 2, the same need is met by obtaining an expansion of the current Treasury facility by $200 million. Assuming now that the Treasury facility, once expanded, remains available at its expanded level, in future rate cases, and then the reliance on Transmission reserves must at some point stop, because those reserves will ultimately be used for a Transmission-related purpose. Now suppose that during the FY 2010-2011 rate period, Power needs to make use of the $200 million of liquidity in both scenarios, and is now looking at setting rates for the 2012-2013 period. In scenario 1, Power has used the liquidity supplied by the Transmission reserves, so it has to repay that use. In addition, it has to come up with more liquidity, since per these assumptions, the Transmission reserves are no longer available to Power. In scenario 2, however, while Power must also repay the use of the liquidity provided by the Treasury facility, once the facility has been paid off, it is once again available and is providing liquidity – Power does not have to replace the liquidity.

Q. Is there a distinction between permanent and temporary liquidity?

A. Reserves attributed to Power and the Treasury facility both provides permanent liquidity for Power – a long-term way to obtain the temporary use of cash. Reserves attributed to Transmission, on the other hand, might be able to provide temporary liquidity for

Power – a short-term way to obtain the temporary use of cash. In the former case, any use of the liquidity must be "repaid," but after that the liquidity is once again available. In the latter case, any use of the liquidity must be "repaid," and after that a new source of liquidity must be found.

Q. *Have you found other sources of additional liquidity that appear promising?*

A. No.

Q. *Have you examined any alternatives to a "standard" two-year rate that does not change from year to year except for the possible application of a CRAC or DDC?*

A. Yes. We have considered both a stepped rate and the possibility of a formal rate adjustment after the first year of the rate period.

Q. *Please explain what you mean by a stepped rate.*

A. Generally speaking, a stepped rate means a predetermined rate that is different for each of the two years of the rate period. Each of the two rates would still be subject to a CRAC or a DDC. Under the stepped rate we examined, the FY 2010 rate would be lower than the equivalent two-year rate and the rate for FY 2011 would be higher than the equivalent two-year rate. This approach to ratemaking allows for a lower rate in FY 2010 when the economy would presumably be just starting to recover from the current recession – thus avoiding a higher rate increase in that year. Then, in FY 2011, when the economy would hopefully be well on its way toward recovery, the rate would increase to above what it would otherwise be in a two-year construct at a time when consumers could more easily absorb such an increase. We present some numerical results of stepped rates at the bottom of Attachment 1.

Q. *Would such a stepped rate construct be feasible and attractive to BPA?*

A. From a technical perspective, stepped rates would be much like two-year average rates in that there would be only one rate case, covering two years; we would not expect that costs-recovery demonstration to FERC would be very much more complicated, and our risk mechanisms could be readily applied to stepped rates. However, from a process perspective, we see some drawbacks. It is very likely that some new issues would emerge during the design of stepped rates that we would need to resolve. We don't anticipate that we would not be able to resolve them, but we can't know now what they would be (if there are any). It is likely that resolving these issues would take extra time for both BPA and Parties. If Parties are strongly in favor of stepped rates, BPA is willing to consider them. However, given the results in Attachment 1, we believe we will be able to limit the rate increase for FY 2010 sufficiently that the benefit of being able to reduce the FY 2010 rate still further is not likely to be worth the expense of a more complicated rate process and higher rates in FY 2011. Unless between now and the Final Proposal circumstances change in a manner that would make stepping the rates a worthwhile effort, Staff does not believe the additional process is worth the effort.

Q. What kinds of one-year rate adjustment mechanisms have you considered?

A. There is a wide range of formality and complexity of possible adjustment mechanisms. At end of the range, with the most complexity and the heaviest burden of additional process, is a pair of one-year rate periods, with a full-blown 7(i) rate process in FY 2010 to set rates for FY 2011. At the other end of the range, the least-cumbersome process we have discussed is something much like the September process the current GRSPs describe for calculating the possible CRAC or DDC for the subsequent year. This kind of process could be expanded to consider not only the modified net revenue results for the fiscal year that is nearly complete but also some revisions to specified forecast for the coming year, such as the firm load forecast, or the forecast of market prices for electricity.

Q. What is your view of these possibilities for adjustment mechanisms?

A. A full-blown 7(i) process in FY 2010, when we should be beginning the 7(i) process for the first Tiered Rates rate case for FY 2012, seems completely impractical.

Q. *Could an adjustment process be streamlined so much that it might be practical?*

A. The briefest process we have discussed internally is a 30-day, non-7(i) process mainly comprising workshops. In such a series of workshops, BPA could present draft forecast revisions of the variables that were specified in the GRSPs for consideration, allow for public comment, perhaps allow for discussions with certain BPA executives, and then present revisions to rates that would go into effect shortly. Even this level of process would add quite a burden to BPA and Parties. In previous years, Parties have been very reluctant to even consider a process that included some looking forward that was not governed by 7(i). BPA could consider this alternative, but even this amount of process presents considerable strain on the Staffs of BPA and of Parties. Again, the scenario results presented in Attachment 1 show that Staff anticipates that our rates will include a fairly low cost of risk, including the likely impacts of the CRAC, so there is not much cost of risk that could be reduced, and it would seem that reducing the cost of risk would be the main benefit that a one-year rate adjustment mechanism might provide.

Q. *Has BPA considered relaxing the TPP standard in order to reduce the FY 2010-11 rates?*

A. The Administrator has the discretion to relax the TPP standard in order to reduce rates, and in previous rate cases, Administrators have sometimes exercised that discretion. Given the success we anticipate in securing both cost reductions and risk tools, BPA staff think it is very likely that we will be able to avoid large rate increases, in which case relaxing the TPP standard and accepting a higher risk of deferring some of our Treasury payments would not be prudent. Of particular note is that if we are successful in expanding the Treasury facility, the expected cost of risk will be quite low, and relaxing the TPP standard would not be able to reduce the cost of risk, and hence the rate, very much if at all.

Q. Where can we find the cost of risk in your results?

A. To find the cost of risk, look at the results in Attachment 1. One common cost of risk is PNRR, which in all of the scenarios shown in Attachment 1 is $0; this cost obviously cannot be reduced. The remaining cost of risk comes from the operation of the CRAC and DDC. The "effective rate," or "post-risk" rate, is the pre-risk rate plus the expected value of the rate increases from CRAC collections minus the expected value of the rate decreases from DDC distributions. You can see the cost of risk by comparing the "pre-risk" rate percentage to the "2-yr Ave." "post-risk" rate percentage. In most of the scenarios, the post-risk rate is actually lower than the pre-risk rate, meaning that the expected value of DDC distributions is larger than the expected value of CRAC collections, that is, the cost of risk is actually negative.

Section 4: What-if Simulation Results

Q. What can you tell us about the possible rate impacts of the external circumstances and the cost tools and risk tools you have described?

A. We have run 30 scenarios through our rates-risk modeling tools; results are shown in Attachment 1. We are showing pre-risk average rate levels for non-Slice PF and risk results, including the expected value of the approximate post-risk rates when the effects of the CRAC and DDC are incorporated. We show results for the three different gas prices assumptions described previously, and for two different possible expected value outcomes for 2009 MNR results (negative $250 million and negative $350 million). We show two different levels of cost cuts, $0 and $50 million per year. For most scenarios, we show results for two different levels of additional liquidity, $200 million and $400 million, and for three scenarios we show the same set of results for no additional liquidity so that the benefit of the first $200 million of additional liquidity can be seen. In addition, we show the impact on the Slice Rate.

Q. Are you essentially updating the Initial Proposal, or providing a new proposal?

A. We are presenting the results of many what-if questions. It is important to realize that these results represent neither an update of the Initial Proposal nor a forecast of BPA's Final Proposal. They indicate the kind of impact a relatively small number of potential changes can have, absent other updates or changes in response to other materials introduced into the rate case record.

Q. Please describe the assumptions in each scenario.

A. Each scenario is based on a gas price forecast. The scenarios based on the forecast labeled $7.25 use the same forecast as in the Initial Proposal. The other scenarios use either the $5.25 or $4 gas price forecasts. These are Henry Hub prices; the average prices at Sumas for the three scenarios are about $6.80, $5.50, and $4.25 respectively.

The second assumption is the distribution of 3,500 results for FY 2009 Power MNR. In the Initial Proposal, the expected value of this distribution was -$91 million, and the standard deviation of this distribution was over $200 million. The scenarios presented here are based on one of two modified distributions. One distribution has an expected value of negative $250 million, and the other has an expected value of negative $350 million. In other words, one is about $160 million worse than the Initial Proposal, and the other is about $260 million worse. Both of these distributions have smaller standard deviations, reflecting the passage of time since the data for the Initial Proposal was frozen; since then, much of 2009 that was in the future has become the past, and therefore actual, and our uncertainty about the remaining future of 2009 has been reduced, *e.g.*, as more information about the total runoff for 2009 has increased.

Q. What changes in cost are reflected in these results?

A. We are showing two levels of cost cuts relative to the initial proposal, $0 and $50 million per year. The $0 level is the same of costs used in the Initial Proposal; the $50 million per year level has not yet been achieved – it is a what-if value that illustrates the ways that cost cuts would affect the pre-risk rates and the total post-risk rates.

Q. *What changes in risk tools are incorporated in these scenarios relative to the Initial Proposal?*

A. The bulk of the scenarios show additional liquidity of either $200 million or $400 million. The $400 million level shows the kind of rate and risk impacts of an expanded Treasury facility with no problems about annual or total borrowing limitations. In these scenarios, we have assumed that the additional $400 million of liquidity will be available for future rate periods, and have reduced the threshold for the DDC from $1,050 million to $750 million. $1,050 million is used in the other scenarios, and is the threshold adopted in the WP-07 rates. There are three scenarios that assume no additional liquidity becomes available. These scenarios do not represent likely futures. They are included so that the value of the first $200 million of incremental liquidity can be inferred.

Q. *What assumptions about PNRR did you make in these scenarios?*

A. In all of these scenarios, there is $0 of PNRR, and all of the calibrating of the risk mitigation that we have done has been by adjusting the threshold for the CRAC.

Q. *Are there any other changes in the CRAC from one scenario to another?*

A. All of the scenarios have a cap of $300 million per year for the CRAC except the scenario with $7.25 gas, 2009 MNR of negative $350M, no cost cuts, and no additional liquidity; this scenario could not reach the 95% TPP standard without more risk mitigation, so the cap was increased to $400 million.

Q. *What is the load forecast update?*

A. As described earlier, as a result of incorporating recent information on economic activity slowing down, and of incorporating some corrections in load forecasts, BPA's firm load forecast has been reduced for both FY 2010 and FY 2011. All of the scenarios use the same revised load forecast. The reduction in firm load causes the quantity of augmentation power to decrease. The financial impact of this is different in each of the three gas price scenarios.

Q. What is the 7(b)(2) change?

A. During the effort to examine ways to mitigate the potential rate increase, Staff uncovered an error in the revenue requirements for the 7(b)(2) Rate Test Study. The income statement for the 7(b)(2) Case revenue requirement did not accurately reflect net interest expense. *See* Revenue Requirement Study Documentation, WP-10-E-BPA-02A, Table 1E. The formula that calculated net interest expense, line 29, should have totaled lines 23 through 28. Instead, it only included lines 23 through 27. The interest income, line 28, was inadvertently omitted. As a result, the net interest expense and, therefore, the total 7(b)(2) revenue requirement in the Initial Proposal was overstated by the amount of the credit for interest income, which averaged approximately $50 million per year. All of the scenarios incorporate the corrected net interest expense for the 7(b)(2) revenue requirement.

Q. How were the three stepped rates scenarios constructed?

A. In each of these, the rates for non-Slice PF were first calculated in the normal fashion, and then a post-processing step was conducted that reduced the FY 2010 rates and increased the FY 2011 rates. The FY 2010 reduction and the FY 2011 increase were calculated to generate either 77.4% × $50 million less revenue or more revenue. This change had impacts on BPA's net cash flow, and this rippled through the TPP calculations, resulting in some changes in the post-risk statistics.

Q. What do the rate percentage statistics measure?

A. All of the rate percentage numbers reflect the percentage change in the average non-Slice PF rate *vis a vis* the average 2009 non-Slice PF rate. In particular, the "2011 %" is the average increase in post-risk 2011 average non-Slice PF rates relative to the 2009 average non-Slice PF rates; it is NOT the change from the average 2010 non-Slice PF rates. *See* Attachment 1.

Section 5: Staff Recommendation

Q. What is the staff recommendation with regard to liquidity tools?

A. If we have reached an agreement with Treasury that expands the limit another $400+ million on BPA's ability to conduct short-term borrowing for expenses, we will recommend that the Administrator look solely to this tool to support Power's TPP. If the Administrator determines that there are sufficiently serious, unsolved problems with using the full extent that it would not be reasonable to rely on the full amount of the expanded facility, then we would recommend that the Administrator rely next on the Flexible PF Rate Program to the extent necessary in order to provide up to an additional $400 million total additional liquidity. If additional liquidity is still needed to meet the $400 million target, Staff recommends that the Administrator then look to unused Transmission reserves as a means of reaching the $400 million target.

Q. Does this conclude your testimony?

A. Yes.

Attachment 1

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Attachment 1: Summary of Risk Results

Assumptions

All runs use the same reduced firm load forecasts from early April, 2009
All runs assume original length of CGS outage in 2011 (most likely = 87 days)
All runs have $0 PNRR; risk mitigation adjustments are made via CRAC threshold
All runs have $300M cap on CRAC except 3 B I 0, which has $400M cap

Yellow vs Blue
Cost cuts

$0	$50M/yr
Yellow	Blue

Lighter vs Darker
Additional Liquidity

$0	$200M	$400M
White	Lighter	Darker

Italic or Regular Font
2009 Net Rev results

-$250M	-$350M
Regular	Italic
13.6%	13.6%
10.2%	10.2%

						TPP	Pre-risk rate		Slice	Effective rate, post-risk (after CRAC & DDC)					IOU REP Benefits	
	Run	Gas Pr	2009 NR	Cost cuts	Add'l liq	2-Year	Ave Rate	% Incr.	% Incr.	10 rate	% Incr.	11 rate	% Incr.	2-yr Ave.	Pre-risk	Post-risk
$4.00 gas for 2010-11	1	$4.00	-$250M	0	$200M	96.3%	30.57	13.6%	4.6%	30.57	13.6%	30.34	12.8%	13.2%	239	241
	2	$4.00	-$250M	0	$400M	99.6%	30.57	13.6%	4.6%	30.57	13.6%	29.61	10.1%	11.9%	239	247
	3	$4.00	-$250M	$50M/yr	$200M	96.3%	29.65	10.2%	2.8%	29.65	10.2%	29.42	9.4%	9.8%	245	247
	4	$4.00	-$250M	$50M/yr	$400M	99.6%	29.65	10.2%	2.8%	29.65	10.2%	28.69	6.7%	8.4%	245	253
	5	$4.00	-$350M	0	$0M	95.1%	30.67	14.0%	4.6%	31.16	15.8%	31.56	17.3%	16.6%	240	229
	6	$4.00	-$350M	0	$200M	95.1%	30.67	14.0%	4.6%	30.67	14.0%	30.81	14.5%	14.3%	240	239
	7	$4.00	-$350M	0	$400M	98.4%	30.67	14.0%	4.6%	30.67	14.0%	30.09	11.9%	12.9%	240	244
	8	$4.00	-$350M	$50M/yr	$200M	95.1%	29.74	10.6%	2.8%	29.74	10.6%	29.88	11.1%	10.8%	245	244
	9	$4.00	-$350M	$50M/yr	$400M	98.4%	29.74	10.6%	2.8%	29.74	10.6%	29.16	8.4%	9.5%	245	249
$5.25 gas for 2010-11	11	$5.25	-$250M	0	$200M	95.1%	29.28	8.8%	6.9%	29.28	8.9%	29.69	10.4%	9.6%	246	243
	12	$5.25	-$250M	0	$400M	95.3%	29.28	8.8%	6.9%	29.28	8.8%	28.14	4.6%	6.7%	246	255
	13	$5.25	-$250M	$50M/yr	$200M	95.1%	28.36	5.4%	5.0%	28.36	5.4%	28.77	7.0%	6.2%	251	248
	14	$5.25	-$250M	$50M/yr	$400M	95.3%	28.36	5.4%	5.0%	28.36	5.4%	27.22	1.2%	3.3%	251	260
	15	$5.25	-$350M	0	$0M	95.1%	29.37	9.2%	6.9%	32.50	20.8%	30.31	12.7%	16.7%	245	214
	16	$5.25	-$350M	0	$200M	95.0%	29.37	9.2%	6.9%	29.65	10.2%	30.38	12.9%	11.6%	245	235
	17	$5.25	-$350M	0	$400M	95.1%	29.37	9.2%	6.9%	29.37	9.2%	28.98	7.7%	8.5%	245	248
	18	$5.25	-$350M	$50M/yr	$200M	95.0%	28.46	5.8%	5.0%	28.74	6.9%	29.47	9.6%	8.2%	251	241
	19	$5.25	-$350M	$50M/yr	$400M	95.1%	28.46	5.8%	5.0%	28.46	5.8%	28.07	4.4%	5.1%	251	254
$7.25 gas for 2010-11	21	$7.25	-$250M	0	$200M	95.1%	27.53	2.3%	8.0%	29.43	9.4%	28.51	6.0%	7.7%	242	219
	22	$7.25	-$250M	0	$400M	95.0%	27.53	2.3%	8.0%	27.53	2.3%	27.19	1.1%	1.7%	242	245
	23	$7.25	-$250M	$50M/yr	$200M	95.1%	26.62	-1.0%	6.1%	28.52	6.0%	27.60	2.6%	4.3%	248	226
	24	$7.25	-$250M	$50M/yr	$400M	95.0%	26.62	-1.0%	6.1%	26.62	-1.0%	26.28	-2.3%	-1.7%	248	251
	25	$7.25	-$350M	0	$0M	95.1%	27.61	2.6%	8.0%	33.01	22.7%	28.68	6.6%	14.7%	241	191
	26	$7.25	-$350M	0	$200M	95.1%	27.61	2.6%	8.0%	31.09	15.6%	28.61	6.4%	11.0%	241	206
	27	$7.25	-$350M	0	$400M	95.1%	27.61	2.6%	8.0%	28.02	4.2%	28.17	4.7%	4.4%	241	234
	28	$7.25	-$350M	$50M/yr	$200M	95.1%	26.71	-0.7%	6.1%	30.19	12.2%	27.71	3.0%	7.6%	247	212
	29	$7.25	-$350M	$50M/yr	$400M	95.1%	26.71	-0.7%	6.1%	27.12	0.8%	27.27	1.4%	1.1%	247	240

Stepped rate analyses

All 3 runs assume the nonSlice PF rate adjusted down in 2010 and up in 2011 by the equivalent of a cost shift of $50M from 2010 to 2011 (77.4% of that amount would affect the non-Slice rate). Slice rate and REP $ have not been stepped. Otherwise, these scenarios are similar to the same-number runs above w/o "*".

9*	$4.00	-$350M	$50M/yr	$400M	98.7%	29.74	10.5%	2.8%	28.92	7.5%	30.12	12.0%	9.8%	245	248
19*	$5.25	-$350M	$50M/yr	$400M	95.0%	28.46	5.8%	5.0%	27.64	2.8%	29.03	7.9%	5.3%	251	253
29*	$7.25	-$350M	$50M/yr	$400M	95.0%	26.71	-0.7%	6.1%	26.18	-2.7%	28.41	5.6%	1.5%	247	238

R S T U V W X Y Z AA AB AC AD AE AF AG AH

Attachment 1: Summary of Risk Results, continued

					Financial Reserves		CRAC Statistics					DDC Statistics				
Run	Gas Pr	2009 NR	Cost cuts	Add'l liq	Start 10	Ending 11	Thresh.	2010 $	2010 %	2011 $	2011 %	Thresh.	2010 $	2010 %	2011 $	2011 %
1	$4.00	-$250M	0	$200M	543	593	0	0.0	0%	0.1	0%	1,050	0.0	0%	14.4	8%
2	$4.00	-$250M	0	$400M	543	541	0	0.0	0%	0.1	0%	750	0.1	0%	60.8	30%
3	$4.00	-$250M	$50M/yr	$200M	543	593	0	0.0	0%	0.1	0%	1,050	0.0	0%	14.4	8%
4	$4.00	-$250M	$50M/yr	$400M	543	541	0	0.0	0%	0.1	0%	750	0.1	0%	60.8	30%
5	*$4.00*	*-$350M*	*0*	*$0M*	*440*	*594*	*440*	*31.0*	*51%*	*64.7*	*38%*	*1,050*	*0.0*	*0%*	*9.4*	*5%*
6	*$4.00*	*-$350M*	*0*	*$200M*	*440*	*512*	*205*	*0.0*	*0%*	*17.0*	*16%*	*1,050*	*0.0*	*0%*	*8.7*	*4%*
7	*$4.00*	*-$350M*	*0*	*$400M*	*440*	*463*	*0*	*0.0*	*0%*	*0.9*	*2%*	*750*	*0.0*	*0%*	*37.5*	*19%*
8	*$4.00*	*-$350M*	*$50M/yr*	*$200M*	*440*	*512*	*205*	*0.0*	*0%*	*17.0*	*16%*	*1,050*	*0.0*	*0%*	*8.7*	*4%*
9	*$4.00*	*-$350M*	*$50M/yr*	*$400M*	*440*	*463*	*0*	*0.0*	*0%*	*0.9*	*2%*	*750*	*0.0*	*0%*	*37.5*	*19%*
11	$5.25	-$250M	0	$200M	543	578	365	0.1	1%	47.5	27%	1,050	0.0	0%	21.7	10%
12	$5.25	-$250M	0	$400M	543	478	0	0.0	0%	1.3	2%	750	0.1	0%	73.6	32%
13	$5.25	-$250M	$50M/yr	$200M	543	578	365	0.1	1%	47.5	27%	1,050	0.0	0%	21.7	10%
14	$5.25	-$250M	$50M/yr	$400M	543	478	0	0.0	0%	1.3	2%	750	0.1	0%	73.6	32%
15	*$5.25*	*-$350M*	*0*	*$0M*	*440*	*719*	*640*	*196.3*	*100%*	*88.3*	*44%*	*1,050*	*0.0*	*0%*	*30.2*	*14%*
16	*$5.25*	*-$350M*	*0*	*$200M*	*440*	*533*	*410*	*18.0*	*35%*	*77.9*	*40%*	*1,050*	*0.0*	*0%*	*14.5*	*7%*
17	*$5.25*	*-$350M*	*0*	*$400M*	*440*	*421*	*145*	*0.0*	*0%*	*23.9*	*19%*	*750*	*0.0*	*0%*	*49.0*	*22%*
18	*$5.25*	*-$350M*	*$50M/yr*	*$200M*	*440*	*533*	*410*	*18.0*	*35%*	*77.9*	*40%*	*1,050*	*0.0*	*0%*	*14.5*	*7%*
19	*$5.25*	*-$350M*	*$50M/yr*	*$400M*	*440*	*421*	*145*	*0.0*	*0%*	*23.9*	*19%*	*750*	*0.0*	*0%*	*49.0*	*22%*
21	$7.25	-$250M	0	$200M	543	682	660	119.1	94%	98.7	47%	1,050	0.0	0%	37.7	17%
22	$7.25	-$250M	0	$400M	543	467	335	0.0	0%	56.4	29%	750	0.1	0%	78.6	32%
23	$7.25	-$250M	$50M/yr	$200M	543	682	660	119.1	94%	98.7	47%	1,050	0.0	0%	37.7	17%
24	$7.25	-$250M	$50M/yr	$400M	543	467	335	0.0	0%	56.4	29%	750	0.1	0%	78.6	32%
25	*$7.25*	*-$350M*	*0*	*$0M*	*440*	*818*	*790*	*337.6*	*100%*	*119.6*	*47%*	*1,090*	*0.0*	*0%*	*52.8*	*23%*
26	*$7.25*	*-$350M*	*0*	*$200M*	*440*	*686*	*665*	*217.8*	*100%*	*100.2*	*47%*	*1,050*	*0.0*	*0%*	*37.5*	*17%*
27	*$7.25*	*-$350M*	*0*	*$400M*	*440*	*451*	*430*	*26.2*	*46%*	*92.4*	*43%*	*750*	*0.0*	*0%*	*58.0*	*25%*
28	*$7.25*	*-$350M*	*$50M/yr*	*$200M*	*440*	*686*	*665*	*217.8*	*100%*	*100.2*	*47%*	*1,050*	*0.0*	*0%*	*37.5*	*17%*
29	*$7.25*	*-$350M*	*$50M/yr*	*$400M*	*440*	*451*	*430*	*26.2*	*46%*	*92.4*	*43%*	*750*	*0.0*	*0%*	*58.0*	*25%*
*9**	*$4.00*	*-$350M*	*$50M/yr*	*$400M*	*440*	*471*	*0*	*0.0*	*0%*	*2.3*	*4%*	*750*	*0.0*	*0%*	*29.4*	*15%*
*19**	*$5.25*	*-$350M*	*$50M/yr*	*$400M*	*440*	*429*	*95*	*0.0*	*0%*	*24.1*	*19%*	*750*	*0.0*	*0%*	*39.8*	*18%*
*29**	*$7.25*	*-$350M*	*$50M/yr*	*$400M*	*440*	*463*	*410*	*18.0*	*35%*	*102.2*	*47%*	*750*	*0.0*	*0%*	*46.3*	*20%*