

**UNITED STATES DEPARTMENT OF ENERGY  
BEFORE THE  
BONNEVILLE POWER ADMINISTRATION**

**2010 RATE ADJUSTMENT  
PROCEEDING**

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) **Docket Number BP-12**  
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**REBUTTAL TESTIMONY  
OF  
NORTHWEST REQUIREMENTS UTILITIES**

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**WITNESSES:**

**GEOFFREY H. CARR**

**JOHN D. SAVEN**

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**SUBJECT:**

**IRRIGATION DISCOUNT AND LOW DENSITY DISCOUNT**

**March 8, 2011**

1 *Q. What is the purpose of your testimony?*

2

3 A. To respond to the Errata to Power Rates Study Documentation, BPA-12-E-BPA-01A  
4 filed by BPA as BP-12-E-BPA-01A-E04 regarding the calculation of the Irrigation Rate  
5 Discount (IRD). In this errata, BPA changes the methodology for calculating the Irrigation  
6 Discount from the Initial Rate Proposal. While recognizing that the final IRD will not be set  
7 until the end of the rate process, BPA forecasts that based on the changed methodology, the level  
8 of the IRD would decline from 12.09 mills per kilowatthour in the Initial Rate Proposal to a  
9 forecast of 10.70 in the errata unadjusted for errors, and a further expected reduction to 10.58  
10 mills per kilowatthour for errors (described below), a total reduction of about 12.5%. See, BP-  
11 12-E-BPA-01A-E04.

12

13 *Q. Is NIU staff familiar with the Irrigation Discount Proposal and the history of BPA's rate*  
14 *setting for qualifying irrigation loads?*

15

16 A. Yes. As Executive Director of Northwest Irrigation Utilities I have been involved in the  
17 previous Irrigation Discount, the design of the FY 96 – FY 01 Summer Seasonal Product, and the  
18 FY 02 – FY 11 Irrigation Rate Mitigation Product. The staff of NIU also participated in the  
19 development of the proposed Irrigation Rate Discount in the Regional Dialogue process, Load  
20 Following contract negotiations regarding Exhibit D where qualifying irrigation loads are  
21 established, the Tiered Rate Methodology (TRM), and this wholesale power services rate case.  
22 We work closely with the NIU members to determine the impact of irrigation mitigation in  
23 conjunction with other changes in BPA wholesale power rate design on members' power supply  
24 costs.

25

26 *Q. Over these many years how would you describe the link between the irrigation rate*  
27 *mitigation programs and BPA's Priority Firm rate structure?*

28

29 A. Irrigation loads are seasonal, with nearly 90% generally occurring in the May –  
30 September period. BPA's wholesale rate design sends price signals based largely on market  
31 forecasts of energy during different seasons of the year, represented by monthly HLH and LLH

1 charges. Through these historic irrigation mitigation programs, for a capped amount of  
2 irrigation energy during the summer period, or for the entire irrigation load, BPA has provided a  
3 price reduction to NIU members and others customers with relatively large irrigated agricultural  
4 load from the Priority Firm energy rates for their irrigation loads. Irrigation load above any  
5 capped amounts are charged the PF rate. This has been a workable balance over the years. BPA  
6 has sent price signals when needed to increase wholesale power rates in the summer, compared  
7 to other seasons, while maintaining a viable price structure for qualifying seasonal irrigation  
8 loads, consistent with the Agency's historic support of service to rural areas that have a  
9 significant percentage of agricultural loads.

10  
11 *Q. Can you provide an example of the load profile of a representative NIU member and the*  
12 *scale of irrigation loads?*

13  
14 A. Yes, for Big Bend Electric we have reviewed a BPA rate model Account Executives use  
15 to help utilities forecast the impacts of new wholesale power rates. For Big Bend Electric, a 60  
16 aMW utility, over 65% of its annual load occurs in the May – September period. During those 5  
17 months, over 79% of the load is irrigation that qualifies for the Irrigation Rate Mitigation Product  
18 (IRMP) at 209,669 MWh. Nearly 40% of the annual load of the utility is irrigation that qualifies  
19 for the IRMP. To the extent Big Bend experiences load growth in the irrigation sector, or has  
20 higher than expected irrigation loads in a particular year that are weather related, because the  
21 irrigation amounts qualifying for the Discount are currently contractually capped, the utility  
22 faces the full charges for such load growth or load shaping.

23  
24 *Q. What was the expectation of the NIU members as result of moving to the Tiered Rates*  
25 *Methodology including the continuation of an Irrigation Discount?*

26  
27 A. The NIU members with proportionately high irrigation loads, such as Harney Electric,  
28 Big Bend Electric, Surprise Valley Electric, Columbia Power expected to see a rate decrease  
29 associated with the TRM (holding aside BPA general cost increases). See Exhibit 1, BPA Graph  
30 C. However, with the BPA change in Load Shaping Rates contained in the Initial Proposal,  
31 these utilities are all faced with rate increases associated with the TRM. See Exhibit 2, BPA

1 Graph D. For many of these utilities, this represents a 5% or larger overall change in power  
2 supply costs for the total retail load compared to what was previously anticipated. These are  
3 significant differences. While the TRM did not guarantee any particular outcome for individual  
4 customers, these overall increases for NIU members are driven by significantly higher costs for  
5 the summer peaking utilities in the summer periods when irrigation loads occur. We believed  
6 that some of these changes would be mitigated by an Irrigation Discount at the level of 12.09  
7 mills/kWh in the Initial Proposal. And this was reflected in the rate impacts as they were first  
8 described by the BPA Account Executives to the customers when the Initial Proposal was released  
9 late last year. Then BPA determined there was an error in the Irrigation Discount formula and  
10 subsequently began showing the NIU members new model results with a lower Irrigation  
11 Discount and higher rates.

12  
13 *Q. What does this mean for an NIU member such as Big Bend Electric?*

14  
15 *A. Load Following customers were forecast on average to have a 9.2% wholesale rate*  
16 *increase tied to increases in BPA costs, and individual utilities would be higher or lower*  
17 *depending upon rate design impacts from the TRM. Rather than seeing a decrease from the*  
18 *9.2% average, in the attached November 17 model run from BPA, Big Bend is faced with a*  
19 *14.65% increase from FY 2010 rates with Lookback and no CRAC compared to BP 12 effective*  
20 *Tier 1 rates with Lookback, using the same load forecast. See Exhibit 3. This is attributed*  
21 *largely to a lower than expected Irrigation Discount, now down from 12.09 mills/kWh to 10.62*  
22 *mills/kWh, used in this November 17 model run, and the impacts of the Load Shaping Charge.*  
23 *BPA in the errata has subsequently reduced the proposed Irrigation Discount to 10.58 mills/kWh,*  
24 *making Big Bend's expected rate increase even higher. We can show similar results for other*  
25 *NIU members with a high percentage of irrigation loads compared to total retail loads, such as*  
26 *Harney Electric and Surprise Valley.*

27  
28 *Q. Do the Members of Northwest Irrigation Utilities support the methodology for*  
29 *determining the Irrigation Discount and level of the benefits provided by the Irrigation Discount*  
30 *in the BPA Errata regarding the Irrigation Discount?*

31

1 A. No they do not. The resulting Irrigation Discount is too low, and the methodology for  
2 deriving it is difficult to accept. However, the underlying problem is not simply the level of the  
3 Irrigation Discount, but rather the cost of BPA power during the summer period.  
4

5 *Q. Why Do the Members of NIU believe the methodology of determining the Irrigation*  
6 *Discount is unfair?*  
7

8 A. When BPA issued the errata for the Irrigation Discount calculation, it contained a 37.47%  
9 reduction for all qualifying irrigation loads for FY 2012 (see Exhibit 4, Irrigation Discount  
10 Projection), based on the actual percentage value of the Irrigation Rate Mitigation Program for  
11 FY 2009 as a reduction to Priority Firm service rates. When BPA initially calculated the level  
12 of benefits Load Following and Slice Block customers received from the Irrigation Rate  
13 Mitigation Product from FY 2009, in the errata, the Agency did not fully take into account  
14 adjustments that were made to the benefit levels Load Following customers received. In  
15 clarification with BPA staff, NIU staff discovered that the errata did not include the full amount  
16 of FY 2009 credits that were paid to Load Following customers in a subsequent period. Then  
17 BPA staff also determined that the errata did not include an adjustment to the Slice/Block  
18 customers' amounts for under recovery of FY 2009 costs. When taken together these two  
19 actions reduced the FY 2009 percentage from 37.47% to 37.06%, which is now the figure BPA  
20 is using.  
21

22 By BPA aggregating the Slice/Block and the Load Following customers together into a single  
23 determination of a percentage value of the IRMP from FY 2009, the Load Following customers  
24 are doubly harmed. For FY 2012 rates, Load Following customers do not get the full benefit of  
25 the 2009 subsequent billing credit they received exclusively as a class. Simultaneously, Load  
26 Following customers' percentage value from 2009 is reduced because BPA applies a  
27 proportionate share by total irrigation load of the billing error underpayment due exclusively to  
28 the Slice/Block customers to the Load Following customers. This disadvantage for the Load  
29 Following customers is in part offset by BPA aggregating the Low Density Discounts of all  
30 customers. By aggregating all customers, the initially proposed Irrigation Discount at 12.09

1 mills/kWh, then revised to 10.70 mills in the errata, declines even further to 10.58 mills/kWh in  
2 revisions to the errata.

3

4 *Q. Could BPA establish two Irrigation Discounts rather than one?*

5

6 A. Yes. The TRM describes the methodology by which an Irrigation Discount is determined  
7 but does not prohibit the Administrator from establishing more than one discount. There is  
8 nothing in the TRM, as amended by the unanticipated consequence language, in the July 2007  
9 Long Term Regional Dialogue ROD or in power sales contracts that prohibits the Administrator  
10 from setting more than one Irrigation Discount, provided that such discount conforms with the  
11 general policy guidance established. *See* Tier Rate Methodology, TRM-12-A-02, Section 10.3,  
12 p. 88-90; (November 2008); Tiered Rate Methodology Record of Decision, TRM-12-A-01,  
13 Section 7.2.7, p. 126 (November 2008); Long-Term Regional Dialogue Record of Decision, p.  
14 127-132 (July 2007); Regional Dialogue Contract, Load Following, Slice, and Block Templates  
15 (September 2010). These documents refer to rate design and application features being  
16 developed in each rate case that implements the TRM and that will appear in the GRSPs.

17

18 *Q. What would be the financial consequence of establishing two Irrigation Discounts, one*  
19 *for Load Following customers and one for Slice Block Customers?*

20

21 A. We have used the same methodology as BPA in determining a separate Irrigation  
22 Discount for Load Following and Slice/Block customers. *See* Exhibit 4, Irrigation Discount  
23 Projection as Revised. Rather than a 37.06 IRD percentage for all customers, we derive a  
24 38.10% IRD reduction for Load Following customers and a 6.55% LDD. For Slice/Block  
25 customers the number is 36.06% and a 3.42% LDD. Based on the loads of these two groups the  
26 resulting Irrigation Discounts are 10.68% for Load Following and 10.47 for Slice Block,  
27 compared to 10.58 using the BPA methodology for all customers. This would be a 0.1 mill/kWh  
28 increase in the Irrigation Discount for Load Following customers.

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30 *Q. What would be the impact on Big Bend Electric of a 0.1 mill/kWh adjustment in the*  
31 *Irrigation Discount?*

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A. Based upon 209,669,540 kWh of qualifying irrigation loads, a 0.1mills/kWh difference is worth about \$21,000 annually. Rather than experiencing more than a 14.65% overall expected overall rate increase, (because the Irrigation Discount would otherwise fall from 10.62 mills/kWh in the November 17 model run to 10.58 mills/kWh) the increase would be lowered to about 14.45%. Also, this annual savings would have a greater impact in the summer period.

*Q. Is NIU recommending the establishment of separate IRMP percentage rates from 2009 and consequently different Irrigation Discount rates for Load Following and Slice/Block customers?*

A. On one hand we can argue that separate Irrigation Discounts would result in a 0.1 mill/kWh increase in the size of the Irrigation Discount for Load Following customers, while resulting in a 0.1 mill/kWh reduction for the Slice/Block customers. More importantly, the differential in percentage reduction from 2009, once fixed will be the basis for the Irrigation Discount rates established in subsequent rate periods. On the other hand, while this difference is noteworthy, it is not compelling in the context of the impacts of the overall TRM and BPA rate design. Our bottom line is a realization that BPA’s initial rate proposal, when combined with this reduced Irrigation Discount will hammer summer seasonal loads, as demonstrated in our example with Big Bend Electric. If BPA can gravitate more toward the load shaping rates in the PF rate structure than in the BP 12 Initial Proposal, then separate Irrigation Discounts would not be necessary. Alternatively, if the load shaping rates turn out to be the same or worse for summer peaking customers than currently proposed, then we recommend a separate Irrigation Discount for Load Following and Slice/Block customers.

*Q. How will those summer seasonal irrigation loads be impacted in the case of Big Bend?*

A. In BPA’s comparison of PF 10 to BP 12 rates in the months of June, July, and August average rates are going up 105%, 75% and 31% respectively (the heart of the irrigation season.) In contrast, during the winter months of November, December and January rates are falling by

1 more than 50%. The average Tier 1 effective rate for Big Bend increases by 11.48 mills/kWh in  
2 June, 12.95 mills/kWh in July and 6.55 mills/kWh in August, when the irrigation loads are most  
3 intensive. A major fear is that the potential rate increases in the summer periods will divide local  
4 communities pitting one customer group against another. Irrigated agriculture is a fiercely  
5 competitive business and irrigators do not have the luxury of simply increasing prices to cover  
6 operational costs and passing them on to product purchasers. In this context, it is hard to see  
7 how BPA's language in the Initial Rate Proposal in support of irrigated agriculture is being met  
8 by what is being offered through rate design.

9

10 *Q. What can BPA do to preserve summer seasonal irrigation loads?*

11

12 A. One option would be for the Administrator to find a way to maintain the 12.09 mill/kWh  
13 Irrigation Discount contained in the BPA Initial Rate Proposal. This would not harm any other  
14 customer from a financial perspective because the cost of the 12.09 mill/kWh Discount is already  
15 built into BPA's initial rate forecast.

16

17 *Q. Is there a better option that would assist seasonal irrigation loads while not shifting costs*  
18 *to other customer groups from what BPA assumed as the value of the Irrigation Discount in the*  
19 *Initial Rate Proposal?*

20

21 A. Yes there is. In the Initial Rate proposal BPA included \$22,751,000 (BPA-01A, Page  
22 135) as the value of the Irrigation Discount, but then drops it to \$20,133,000 in the errata using a  
23 10.70 mill discount, ( *Id.* Table 2.3.3.1) and we would assume to \$19,907,000 if 10.58 mills is  
24 used. NIU recommends an Irrigation Discount for FY-2012 – 2013 where the anticipated cost  
25 would not exceed the initial BPA figure, where the 37.06% reduction BPA derives from 2009 is  
26 applied, but where the qualifying irrigation loads are increased with limitations and conditions  
27 established in the GRSPs.

28

29 *Q. How would this work in general terms?*

30

1 A. Utilities would be allowed to increase the amount of qualifying irrigation load for the  
2 Irrigation Discount during the May through September period by up to 20% in FY 2012 and FY  
3 2013, but not to exceed their Tier 1 amount of power supply. BPA would continue to use the  
4 Irrigation Discount for the qualifying kWh in Exhibit D of the Regional Dialogue contracts, and  
5 the value of this reduction would appear on utilities' bills each month during May – September.  
6 However, when the annual “true up” occurs following September 30<sup>th</sup>, to see if the utility used  
7 all of the contractual kWh, the utility would then be eligible for an additional credit at the same  
8 Irrigation Discount rate. The credit would be for the actual May – September irrigation kWhs  
9 that exceed the Exhibit D contractual amounts, with a limit of 20%. Therefore at the end of the  
10 irrigation season, the utility would pay back BPA if all of the Exhibit D contractual irrigation  
11 kWh were not used, but conversely would receive a credit of up to an additional 20% in the  
12 event that the total use exceeded the contract amount.

13

14 *Q. Would this cost BPA an additional 20% on average beyond the amount otherwise*  
15 *calculated for the Irrigation Discount?*

16

17 A. No it would not because the irrigation loads are very weather sensitive. In some years  
18 they will be well over the current cap, and in other years not as much. For example, Big Bend  
19 Electric has 209,670 MWh qualifying for the Irrigation Discount. In 2010 they had 228,666  
20 MWh or 9% over the cap, but in 2009 they had 258,530 MWh or 23% above the cap. Some NIU  
21 members are relatively close to the capped amount. On average we would estimate that by load  
22 the 20% increase would be reached about 65% of the time, resulting in a 13% increase in the cost  
23 of the IRD compared to the same program without this feature. If BPA's revised cost of the  
24 program in the errata is \$19,907,000, then with a 13% increase, the resulting projected cost at  
25 \$22,495,000 is less than the cost of \$22,751,000 contained in the Initial Rate Proposal.

26

27 *Q. What would be the impact of this proposal on Big Bend Electric's rates?*

28

29 A. Using 209,670 irrigation MWh in Exhibit 3 (Big Bend Electric Coop Contract, Annual  
30 IRMP Amount) a 20% increase in qualifying load occurring 65% of the time would result in  
31 27,257 MWh of additional qualifying irrigation load. At \$10.58 MWh this would be worth

1 \$288,390. For Big Bend, a reduction of this amount from the currently projected \$12,846,963  
2 would mean that current rates at \$11,205,375 would increase to \$12,576,573 This is an increase  
3 of 12.08% compared to the 14.65% increase the utility is currently facing. This would be a  
4 significant improvement.

5  
6 *Q. What about the other NIU members?*

7  
8 A. Many of the NIU members have May – September irrigation loads that are above the  
9 contractual cap. Actual loads are very weather dependent, so it is difficult to forecast. A few  
10 members have been running at or slightly below the cap the for last two years.

11  
12 *Q. How would this be implemented?*

13  
14 A. BPA would revise the proposed GRSPs (BP-12-BPA-09, p. 42-43) regarding the  
15 Irrigation Discount.

16  
17 **1. Discount for Eligible Customers** In May, June, July, August and September, and  
18 eligible Customer shall have the Irrigation Rate Discount of 12.09 mills/kWh applied  
19 to the lesser of the amount of energy purchased at Tier 1 rates in the month or the  
20 irrigation load amounts listed in Exhibit D of its CHWM Contract, **provided that**  
21 **such eligible customer may receive the Irrigation Discount amount for an**  
22 **additional 20% of May-September irrigation load in the form of a credit as**  
23 **described in 2 below.**

24  
25 **2. Irrigation Rate Discount True-Up and Reimbursement** ...If the sum of a  
26 Customer's May to September measured irrigation load is greater than or equal to the  
27 sum of the May through September billed irrigation load amounts, ~~a true-up~~  
28 ~~calculation is not applicable.~~ **and the amount of irrigation load does not exceed**  
29 **the Tier 1 energy purchases, a billing credit shall be provided to such Customer**  
30 **provided that the total credit allowable for the May – September period shall not**  
31 **exceed 20% of the irrigation load amounts listed in Exhibit D.**

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Q. *For what period of time are you proposing this adjustment?*

A. We are proposing this as a rate case issue for FY 2012-2013 only, to provide some protection for our members in light of BPA changes in seasonality. Nothing would be binding beyond this rate period.

Q. *Are there other options the Agency should consider?*

A. In addition, , BPA should further review the seasonal pricing that increase costs in the May – September period, and that are the major drivers in NIU members’ switching from being better off under the new TRM to now being relatively worse off. The impacts are most severe on the utilities such as Harney Electric, Big Bend Electric, Surprise Valley Electric etc, where the overall utility load is summer peaking and cost increases to the summer period are not in turn offset commensurately by decreases to other months. Again, please refer to the BPA graphs C and D of changes to customer rates associated with major adjustments in seasonality. NIU does not know the result of the BPA final seasonality determinations applied to FY 2012 rates. Irrigation customers could be better off or worse off than the numbers we are currently seeing. But what we are seeing now is rate impacts that are too high! BPA could more than offset the reduction in the Irrigation Discount by making modest adjustments to the substantial increases in FY 2012 currently projected rates for the summer period. This would have the effect of reducing Big Bend’s 14.65% currently forecast rate increase because of the disproportionately large amount of irrigation load in the July – August period. When BPA does the final seasonality determination, we would urge the Administrator to keep in mind overall rate impacts and the reductions that have been made to the initial Irrigation Discount.

Q. *Can you summarize your testimony?*

A. Summer peaking customers with irrigation loads are harmed as a result of BPA lowering the Irrigation Discount in the Initial Rate proposal and due to the impact of changes to the Load Shaping charge. NIU states that with the proposed BPA errata to the Irrigation Discount a

1 slightly higher Irrigation Discount should be available to Load Following customers than  
2 Slice/Block customers, however, this differential is nominal and should only be pursued if BPA  
3 does not address the amount of irrigation load that can qualify for the discount, and/or review the  
4 major change in seasonality to partially reduce the excessive cost increases in the summer  
5 period.

6

7 *Q. Does this complete your rebuttal testimony?*

8

9 A. Yes it does.

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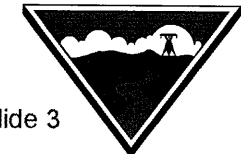
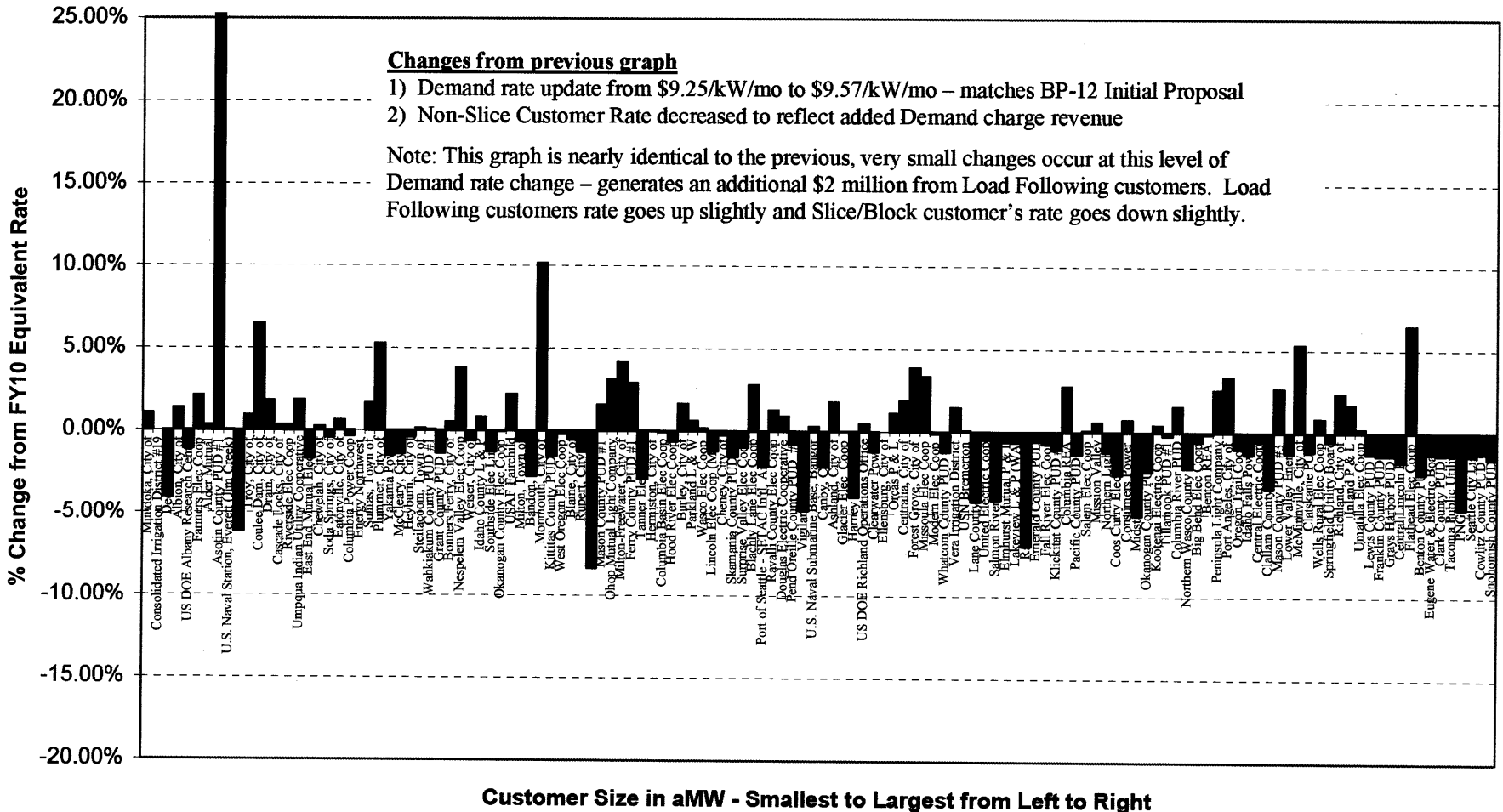
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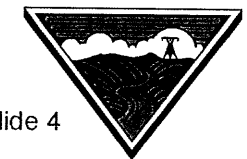
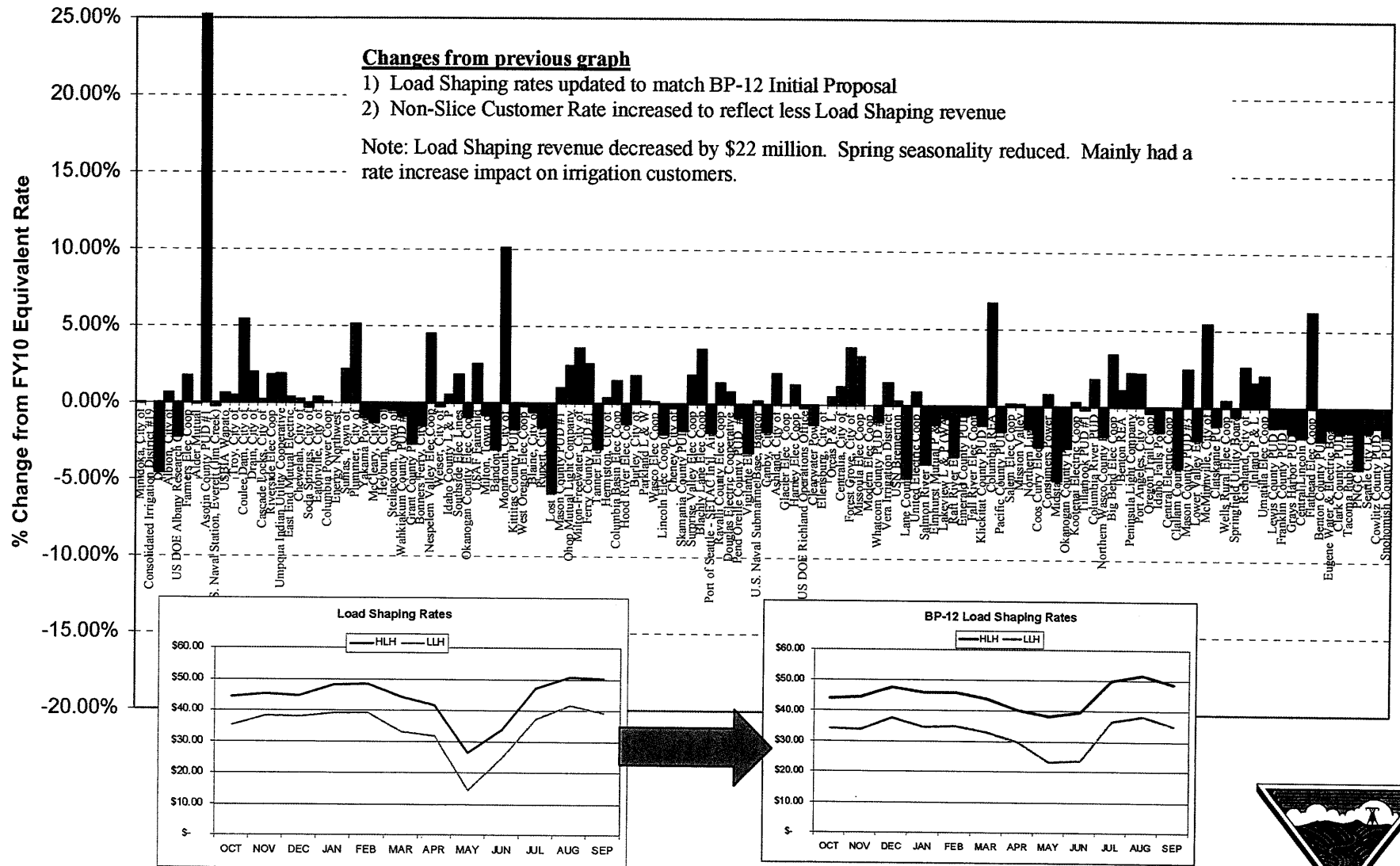
B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

Graph C



B O N N E V I L L E P O W E R A D M I N I S T R A T I O N

Graph D



## MGeM BP-12 Initial Proposal Summary

**Customer (10027) Big Bend Elec Coop****FY 2012 Loads PF-10 RATE vs WP-12 init Nov 17, 2010 Net USBR & updated IRD**

	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
PF-10 Effective Rate (\$/MWh)	28.00	29.55	31.34	26.42	26.97	25.49	22.84	15.05	11.14	17.13	21.21	28.28	87.37
PF-10 Power Costs (\$)	\$1,014,119	\$608,041	\$800,042	\$649,840	\$537,749	\$508,147	\$883,108	\$940,589	\$816,823	\$1,383,571	\$1,566,322	\$1,576,513	5590413.57
WP-TRM Tier 1 Effective Rate (\$/MWh)	31.82	9.06	12.57	12.72	19.99	25.52	38.08	16.43	22.42	29.90	27.57	26.17	24.34
WP-TRM Tier 1 Power Costs (\$)	\$1,142,040	\$183,583	\$316,906	\$308,850	\$392,612	\$500,753	\$1,460,502	\$1,021,958	\$1,637,009	\$2,405,035	\$2,026,936	\$1,450,779	\$12,846,963
FY2012 Projected Total Retail load (aMW)	48.674	28.535	34.308	33.062	28.644	26.836	53.700	84.023	101.838	108.529	99.250	77.413	60.52
FY2012 Projected Tier 1 Sales (aMW)	48.244	28.105	33.878	32.632	28.214	26.406	53.270	83.593	101.408	108.099	98.820	76.983	60.09
SSL (aMW)	54.102	67.532	64.858	65.706	58.549	55.365	45.687	76.643	60.906	54.974	62.006	59.488	60.52

<b>Good Faith Estimate: PF-10 vs. WP-12 (TRM) Power Rate Case Initial Customer (10027) Big Bend Elec Coop FY 2012 Loads</b>				
<b>BPA Tier One Power Rate Comparison (\$/MWh)</b>				
<b>Tier 1 Rates</b>	PF-10	WP-12 (TRM)	% Difference	\$/MWh Diff.
	21.23	24.34	14.7%	3.11
<b>BPA Power Total Cost Comparisons</b>				
Tier 1 Costs	PF-10	WP-12 (TRM)	% Difference	\$ Diff.
	\$11,284,864	\$12,846,963	13.8%	\$1,562,099
Tier 2 and RSS Costs	PF-10	WP-12 (TRM)	% Difference	\$ Diff.
	\$0	\$1,869	N/A	\$1,869
Total BPA Costs (PWR)	PF-10	WP-12 (TRM)	% Difference	\$ Diff.
	\$11,284,864	\$12,848,832	13.9%	\$1,563,967

## Notes:

- (1) This Rate Impact Model uses FY 2012 load forecasts which are published in the Initial Proposal Billing Determinant Model.
- (2) PF-10 Tier 1 Rates and Costs are based on customer's Total Retail Load less Existing Resources and include Lookback credits, LDD and IRMP benefits, and Green Energy Premium. Does not include Conservation Rate Credits (CRC).
- (3) WP-12 Tier 1 Rates and Costs include Lookback credits, LDD and IRD benef
- (4) WP-12 Tier 2 Costs include the following charges: Tier 2 Charges, Resource Support Services Charges, and other resource related charges (such as Transmission Scheduling Service).

**Disclaimer: Bonneville Power Administration provides this spreadsheet as a tool to estimate the impact of power rate proposals on individual customers. BPA makes no commitment to the accuracy of this information and intends that this spreadsheet be used solely for illustrative purposes. All data, formulas, and other content are subject to change at any time.**

Exhibit 3- Northwest Requirements Utilities Rebuttal Testimony

MGeM RIM WP-10

Page 1 of 1

<b>Customer (10027) Big Bend Elec Coop</b>	Non-Slice Lookback %	0.610%	Adjusted LDD	7.3%	PBL GTA Delivery	0%	PBL Load Reg. Rate	\$ -
<b>FY 2012 PF-10 RATE</b>	FY10/FY11 CRC Annual \$	173,412	Irrigation Rate Discount	yes	PBL Provided Load Reg	0%	PF-10 Step	No

Billing Determinants	Oct-2011	Nov-2011	Dec-2011	Jan-2012	Feb-2012	Mar-2012	Apr-2012	May-2012	Jun-2012	Jul-2012	Aug-2012	Sep-2012	Annual	
Customer TRL HLH (BD)	20248.456	11413.959	14272.170	13224.897	11457.639	11593.077	21480.122	34953.420	42364.506	43411.608	42875.818	29726.401	297022.073	193331.752
Customer TRL LLH (BD)	15965.129	9159.702	11253.057	11373.412	8478.653	8345.942	17184.098	27559.427	30958.677	37333.983	30965.868	26010.601	234588.549	152828.556
Total Existing Resources - HLH (BD)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Total Existing Resources - LLH (BD)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
HLH (calc TRL-Exist Res)	20248.456	11413.959	14272.170	13224.897	11457.639	11593.077	21480.122	34953.420	42364.506	43411.608	42875.818	29726.401	297022.073	
LLH (calc TRL-Exist Res)	15965.129	9159.702	11253.057	11373.412	8478.653	8345.942	17184.098	27559.427	30958.677	37333.983	30965.868	26010.601	234588.549	
GSP (BD)	52.531	33.988	42.483	44.445	37.158	40.592	43.478	83.612	108.401	128.932	118.831	104.753	839.204	
LV (TRL)	36213.585	20573.661	25525.227	24598.309	19936.293	19939.019	38664.220	62512.847	73323.183	80745.590	73841.686	55737.002	531610.622	60.520
Green Energy Premium (EPP)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-
IRMP Amount (BD)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	37855.798	56549.500	59385.000	55879.241	0.000	209669.539	
PBL GTA Delivery	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
PBL Provided Load Reg.	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
TTSL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
													0.000	

CHARGES	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual	
HLH	\$636,004	\$382,368	\$498,955	\$392,515	\$347,281	\$325,997	\$566,860	\$770,373	\$845,172	\$1,066,623	\$1,233,966	\$882,874	\$7,948,989	70%
LLH	\$367,358	\$223,772	\$288,641	\$244,073	\$183,817	\$172,010	\$325,982	\$420,006	\$327,852	\$671,638	\$660,812	\$620,093	\$4,506,054	40%
GSP	\$107,689	\$74,434	\$97,712	\$87,112	\$73,945	\$75,095	\$75,651	\$120,401	\$143,090	\$207,580	\$224,590	\$205,316	\$1,492,614	13%
LV	\$17,745	\$10,081	\$12,507	\$12,053	\$9,769	\$9,770	\$18,945	\$30,631	\$35,928	\$39,565	\$36,182	\$27,311	\$260,489	2%
Green Energy Premium (EPP)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	0%
IRMP	\$0	\$0	\$0	\$0	\$0	\$0	\$0	(\$270,587)	(\$404,207)	(\$424,475)	(\$399,416)	\$0	(\$1,498,685)	-13%
PBL GTA Delivery	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	0%
PBL Provided Load Reg.	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	0%
													\$0	0%
LDD Non-Slice	(\$82,604)	(\$50,541)	(\$65,701)	(\$53,841)	(\$44,991)	(\$42,654)	(\$72,259)	(\$98,162)	(\$98,940)	(\$145,289)	(\$157,740)	(\$127,008)	(\$1,039,731)	-9.2%
CRC Credit	(\$14,451)	(\$14,451)	(\$14,451)	(\$14,451)	(\$14,451)	(\$14,451)	(\$14,451)	(\$14,451)	(\$14,451)	(\$14,451)	(\$14,451)	(\$14,451)	(\$173,412)	-2%
Lookback	(\$32,072)	(\$32,072)	(\$32,072)	(\$32,072)	(\$32,072)	(\$32,072)	(\$32,072)	(\$32,072)	(\$32,072)	(\$32,072)	(\$32,072)	(\$32,072)	(\$384,866)	-3%

PF-10 RATE	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep
HLH	31.41	33.50	34.96	29.68	30.31	28.12	26.39	22.04	19.95	24.57	28.78	29.70
LLH	23.01	24.43	25.65	21.46	21.68	20.61	18.97	15.24	10.59	17.99	21.34	23.84
GSP	2.05	2.19	2.30	1.96	1.99	1.85	1.74	1.44	1.32	1.61	1.89	1.96
LV	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49
Green Energy Premium (EPP)	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50
IRMP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-7.15	-7.15	-7.15	-7.15	0.00
PBL GTA Delivery	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PBL Load Reg. Rate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

SUMMARY with Lookback no CRC	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual	May - Aug
<b>PF10 Costs w/ Lookback no CRC</b>	<b>\$1,014,119</b>	<b>\$608,041</b>	<b>\$800,042</b>	<b>\$649,840</b>	<b>\$537,749</b>	<b>\$508,147</b>	<b>\$883,108</b>	<b>\$940,589</b>	<b>\$816,823</b>	<b>\$1,383,571</b>	<b>\$1,566,322</b>	<b>\$1,576,513</b>	<b>\$11,284,864</b>	\$6,283,819
Load on BPA (TRL-exist Res.)	36,214	20,574	25,525	24,598	19,936	19,939	38,664	62,513	73,323	80,746	73,842	55,737	531,611	60.520
<b>PF10 Rate w/ Lookback no CRC</b>	<b>\$28.00</b>	<b>\$29.55</b>	<b>\$31.34</b>	<b>\$26.42</b>	<b>\$26.97</b>	<b>\$25.49</b>	<b>\$22.84</b>	<b>\$15.05</b>	<b>\$11.14</b>	<b>\$17.13</b>	<b>\$21.21</b>	<b>\$28.28</b>	<b>\$21.23</b>	IRMP% of M-S -0.2385

SUMMARY with all credits	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
PF10 Costs w/ all credits	\$999,668	\$593,590	\$785,591	\$635,389	\$523,298	\$493,696	\$868,657	\$926,138	\$802,372	\$1,369,120	\$1,551,871	\$1,562,062	\$11,111,452
Load on BPA (TRL-exist Res.)	36,214	20,574	25,525	24,598	19,936	19,939	38,664	62,513	73,323	80,746	73,842	55,737	531,611
PF10 Rate w/ all credits	\$27.60	\$28.85	\$30.78	\$25.83	\$26.25	\$24.76	\$22.47	\$14.82	\$10.94	\$16.96	\$21.02	\$28.03	\$20.90

Exhibit 3- Northwest Requirements Utilities Rebuttal Testimony

<b>Customer (10027) Big Bend Elec Coop FY 2012</b>	Lookback % PF-02 Rev FY10/FY11 CRC Annual \$	0.472% 173,412	Adjusted LDD Irrigation Rate Discount	7.3% yes	PBL GTA Delivery PBL Provided Load Regulation	EPP option T1 REC Remarketing	n/a no	PNGC? Demand Scalar	no 1
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**\*\*Net USBR & updated IRD**

	FY2012	FY2013		FY2012	FY2013		
T1SFCO	6998	6998	Total Retail Load	60.520	61.510	#	#DIV/0!
Sum of RHWM	6997.998	6997.998	Existing Resources	0.000	0.000	0	#DIV/0!
TOCA %	0.86482%	0.87897%	New Resources (Self Supply)	0.430	1.702		
<b>CHWM</b>	<b>62.118</b>	<b>62.118</b>	Tier 2 Short-Term	0.000	0.000		
<b>RHWM 2012/2013</b>	<b>62.118</b>	<b>62.118</b>	Tier 2 Load Growth	0.000	0.000		
Above-RHWM Load	0.430	1.702	Tier 2 Vintage	0.000	0.000		
First Purchase Period Above-RHWM Election	No T2, all non-fed including up to 8760 AHWM load. If Tier 2, Type? 0		Above-RHWM Served with Load Shaping*	0.000	0.000	Due to difference between forecasts used in setting Above-RHWM loads and setting rates.	

CUSTOMER Data	Oct-2011	Nov-2011	Dec-2011	Jan-2012	Feb-2012	Mar-2012	Apr-2012	May-2012	Jun-2012	Jul-2012	Aug-2012	Sep-2012	Annual		
<b>Customer TRL HLH (BD)</b>	<b>20248.456</b>	<b>11413.959</b>	<b>14272.170</b>	<b>13224.897</b>	<b>11457.639</b>	<b>11593.077</b>	<b>21480.122</b>	<b>34953.420</b>	<b>42364.506</b>	<b>43411.608</b>	<b>42875.818</b>	<b>29726.401</b>	<b>297022.073</b>	60.469	14093.2901
<b>Customer TRL LLH (BD)</b>	<b>15965.129</b>	<b>9159.702</b>	<b>11253.057</b>	<b>11373.412</b>	<b>8478.653</b>	<b>8345.942</b>	<b>17184.098</b>	<b>27559.427</b>	<b>30958.677</b>	<b>37333.983</b>	<b>30965.868</b>	<b>26010.601</b>	<b>234588.549</b>	60.586	
Customer Load CSP (BD)	75.358	43.777	48.795	48.200	43.213	49.027	83.815	120.643	129.913	134.381	123.956	108.648	1009.726	134.381	
Customer aHLH Tier 1 average (calc)	48.244	28.105	33.878	32.632	28.214	26.406	53.270	83.593	101.408	108.099	98.820	76.983	719.652		
Contract Demand Quantity (BD)	11.389	7.982	7.577	6.711	12.357	10.546	17.939	27.306	14.830	6.249	4.573	15.999	143.458		
Irrigation Amounts from Ex D	0.000	0.000	0.000	0.000	0.000	0.000	0.000	32097.789	47948.108	50352.318	47379.798	31891.527	209669.540		
Total Existing Resources - HLH (BD)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Total Existing Resources - LLH (BD)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Total New Resources - HLH (BD)	178.880	172.000	178.880	172.000	172.000	185.760	172.000	178.880	178.880	172.000	185.760	165.120	2112.160	0.430	
Total New Resources - LLH (BD)	141.040	138.030	141.040	147.920	127.280	133.730	137.600	141.040	130.720	147.920	134.160	144.480	1664.960		
<b>Tier 1 Load - HLH (calc)</b>	<b>20069.576</b>	<b>11241.959</b>	<b>14093.290</b>	<b>13052.897</b>	<b>11285.639</b>	<b>11407.317</b>	<b>21308.122</b>	<b>34774.540</b>	<b>42185.626</b>	<b>43239.608</b>	<b>42690.058</b>	<b>29561.281</b>	<b>294909.913</b>		
<b>Tier 1 Load - LLH (calc)</b>	<b>15824.089</b>	<b>9021.672</b>	<b>11112.017</b>	<b>11225.492</b>	<b>8351.373</b>	<b>8212.212</b>	<b>17046.498</b>	<b>27418.387</b>	<b>30827.957</b>	<b>37186.063</b>	<b>30831.708</b>	<b>25866.121</b>	<b>232923.589</b>		
<b>System Shaped Load - HLH (calc)</b>	<b>25397.449</b>	<b>29856.581</b>	<b>29351.335</b>	<b>29762.572</b>	<b>25114.305</b>	<b>25000.345</b>	<b>19532.792</b>	<b>35760.710</b>	<b>28074.092</b>	<b>25688.136</b>	<b>30133.673</b>	<b>26593.279</b>	<b>330265.268</b>	67.236	
<b>System Shaped Load - LLH (calc)</b>	<b>14854.315</b>	<b>18833.819</b>	<b>18903.208</b>	<b>19122.335</b>	<b>15635.796</b>	<b>16135.571</b>	<b>13361.693</b>	<b>21261.693</b>	<b>15778.133</b>	<b>15212.510</b>	<b>15998.563</b>	<b>16237.922</b>	<b>201335.557</b>	51.998	60.519
TTSL (GTA Delivery %)															
PBL Provided Load Reg.(% TRL)															

Billing Determinants	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual		
Demand (MW)	15.295	7.260	6.910	8.427	2.212	11.645	12.176	9.314	13.245	19.603	20.133	15.236	141.456		
Load Shaping HLH (MWh)	-5327.872	-18614.622	-15258.045	-16709.674	-13828.666	-13593.028	1775.331	-986.170	14111.534	17551.472	12556.385	2968.002	-35355.355		
Load Shaping LLH (MWh)	969.774	-9812.146	-7791.191	-7896.844	-7284.423	-7923.359	3684.805	6156.694	15049.825	21973.553	14833.146	9628.199	31588.032		
Tier 2 Short Term (MWh)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		
Tier 2 Load Growth (MWh)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		
Tier 2 Vintage (MWh)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000		
New Resources (Self Supply MWh)	319.920	310.030	319.920	319.920	299.280	319.490	309.600	319.920	309.600	319.920	319.920	309.600	3777.120	0.430	
Green Energy Premium	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
GTA Delivery (KW)															
PBL Provided Load Reg.(MWh)															

Notes:

\* Above-RHWM Load Shaping Amounts are included in Tier 1 charges and loads.

\*\*Resource related charges include Grandfathered GMS, Resource Support Services (DFS, FORS, and SCS), and Transmission Scheduling Services (TSS and TCMS)

Exhibit 3- Northwest Requirements Utilities Rebuttal Testimony

CHARGES (DOLLARS)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual	Share of Total
Composite Charge (% of System)	\$1,726,988	\$1,726,988	\$1,726,988	\$1,726,988	\$1,726,988	\$1,726,988	\$1,726,988	\$1,726,988	\$1,726,988	\$1,726,988	\$1,726,988	\$1,726,988	\$20,723,853	161.3%
Non-Slice Charge	-\$390,616	-\$390,616	-\$390,616	-\$390,616	-\$390,616	-\$390,616	-\$390,616	-\$390,616	-\$390,616	-\$390,616	-\$390,616	-\$390,616	-\$4,687,394	-36.5%
Net Customer Charge	\$1,336,372	\$1,336,372	\$1,336,372	\$1,336,372	\$1,336,372	\$1,336,372	\$1,336,372	\$1,336,372	\$1,336,372	\$1,336,372	\$1,336,372	\$1,336,372	\$16,036,459	124.8%
Demand	\$143,006	\$68,682	\$69,996	\$82,083	\$21,567	\$109,000	\$104,348	\$75,906	\$111,129	\$206,807	\$221,265	\$158,150	\$1,371,939	10.7%
Load Shaping HLH	-\$234,213	-\$827,978	-\$726,588	-\$764,969	-\$634,321	-\$598,093	\$71,510	-\$37,800	\$557,264	\$671,431	\$649,165	\$144,839	-\$1,529,754	-11.9%
Load Shaping LLH	\$33,118	-\$332,926	-\$291,780	-\$274,178	-\$253,935	-\$260,916	\$109,660	\$142,035	\$356,982	\$803,353	\$569,148	\$337,468	\$938,028	7.3%
Tier 2 Short Term	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	0.0%
Tier 2 Load Growth	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	0.0%
Tier 2 Vintage	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	0.0%
TSS TCMS **	\$156	\$156	\$156	\$156	\$156	\$156	\$156	\$156	\$156	\$156	\$156	\$156	\$1,869	0.0%
Irrigation Rate Discount	\$0	\$0	\$0	\$0	\$0	\$0	\$0	-\$340,879	-\$509,209	-\$534,742	-\$503,173	-\$338,688	-\$2,226,691	-17.3%
Low Density Discount	-\$93,543	-\$17,866	-\$28,393	-\$27,757	-\$34,371	-\$42,909	-\$118,687	-\$110,976	-\$172,829	-\$235,486	-\$203,140	-\$144,661	-\$1,230,619	-9.6%
Lookback Credit (COU allocation ++)	-\$42,700	-\$42,700	-\$42,700	-\$42,700	-\$42,700	-\$42,700	-\$42,700	-\$42,700	-\$42,700	-\$42,700	-\$42,700	-\$42,700	-\$512,400	-4.0%
Green Energy Premium (EPP)	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	0.0%
GTA Delivery	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	0.0%
PBL Provided Load Reg.	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	0.0%
<b>TOTAL Power Charges</b>	<b>\$1,142,195</b>	<b>\$183,738</b>	<b>\$317,062</b>	<b>\$309,006</b>	<b>\$392,768</b>	<b>\$500,908</b>	<b>\$1,460,658</b>	<b>\$1,022,114</b>	<b>\$1,637,165</b>	<b>\$2,405,191</b>	<b>\$2,027,092</b>	<b>\$1,450,935</b>	<b>\$12,848,832</b>	\$8,542,496
Total PF Load (Tier 1 and Tier 2 ) [MWh]	35,893.665	20,263.631	25,205.307	24,278.389	19,637.013	19,619.529	38,354.620	62,192.927	73,013.583	80,425.670	73,521.766	55,427.402	527,833.502	60.090
<b>Total Effective Rate</b>	<b>\$31.82</b>	<b>\$9.07</b>	<b>\$12.58</b>	<b>\$12.73</b>	<b>\$20.00</b>	<b>\$25.53</b>	<b>\$38.08</b>	<b>\$16.43</b>	<b>\$22.42</b>	<b>\$29.91</b>	<b>\$27.57</b>	<b>\$26.18</b>	<b>\$24.34</b>	35.94%

++ Current assumption based on the non-final state of Settlement discussions

TIER ONE SYSTEM DATA	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual	IRMP %M-S
HLH by Month	416	400	416	400	400	432	400	416	416	400	432	384	4912	-26.07%
LLH by Month	328	321	328	344	296	311	320	328	304	344	312	336	3872	8784
Tier 1 System Capability - HLH	2936732	3452346	3393924	3441476	2903992	2890815	2258596	4135047	3246235	2970345	3484387	3075007	38188903	
Tier 1 System Capability - LLH	1717619	2177773	2185797	2211135	1807983	1865772	1545026	2458511	1824441	1759038	1849930	1877607	23280631	

WP-12 Init Nov 17, 2010 Net USBR & updated IRD Rates	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Composite Charge (TOCA) (\$/MWh)	\$1,996,933	\$1,996,933	\$1,996,933	\$1,996,933	\$1,996,933	\$1,996,933	\$1,996,933	\$1,996,933	\$1,996,933	\$1,996,933	\$1,996,933	\$1,996,933	\$1,996,933
Non-Slice Charge (\$/MWh)	-\$451,673	-\$451,673	-\$451,673	-\$451,673	-\$451,673	-\$451,673	-\$451,673	-\$451,673	-\$451,673	-\$451,673	-\$451,673	-\$451,673	-\$451,673
Demand (\$/MWh)	\$9.35	\$9.46	\$10.13	\$9.74	\$9.75	\$9.36	\$8.57	\$8.15	\$8.39	\$10.55	\$10.99	\$10.38	\$10.38
Load Shaping - HLH (\$/MWh)	\$43.96	\$44.48	\$47.62	\$45.78	\$45.87	\$44.00	\$40.28	\$38.33	\$39.49	\$49.65	\$51.70	\$48.80	\$48.80
Load Shaping - LLH (\$/MWh)	\$34.15	\$33.93	\$37.45	\$34.72	\$34.86	\$32.93	\$29.76	\$23.07	\$23.72	\$36.56	\$38.37	\$35.05	\$35.05
Irrigation Rate Discount (\$/MWh)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$10.62	\$10.62	\$10.62	\$10.62	\$10.62	\$10.62
Tier 2 Short Term (\$/MWh)	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32
Tier 2 Load Growth (\$/MWh)	\$48.69	\$48.69	\$48.69	\$48.69	\$48.69	\$48.69	\$48.69	\$48.69	\$48.69	\$48.69	\$48.69	\$48.69	\$48.69
Tier 2 Vintage (\$/MWh)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
Green Energy Premium (\$/MWh) est.	\$10.50	\$10.50	\$10.50	\$10.50	\$10.50	\$10.50	\$10.50	\$10.50	\$10.50	\$10.50	\$10.50	\$10.50	\$10.50
GTA Delivery	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
PBL Provided Load Reg.	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
BPA Tier 2 Average Price (\$/MWh)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00

SUMMARY Tier 1*	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual	All
<b>Tier 1 Charges</b>	<b>\$1,142,040</b>	<b>\$183,583</b>	<b>\$316,906</b>	<b>\$308,850</b>	<b>\$392,612</b>	<b>\$500,753</b>	<b>\$1,460,502</b>	<b>\$1,021,958</b>	<b>\$1,637,009</b>	<b>\$2,405,035</b>	<b>\$2,026,936</b>	<b>\$1,450,779</b>	<b>\$12,846,963</b>	13.84%
Tier 1 Load	35894	20264	25205	24278	19637	19620	38355	62193	73014	80426	73522	55427	527,834	60.090
<b>Tier 1 Effective Rate</b>	<b>\$31.82</b>	<b>\$9.06</b>	<b>\$12.57</b>	<b>\$12.72</b>	<b>\$19.99</b>	<b>\$25.52</b>	<b>\$38.08</b>	<b>\$16.43</b>	<b>\$22.42</b>	<b>\$29.90</b>	<b>\$27.57</b>	<b>\$26.17</b>	<b>\$24.34</b>	
PF-10 Effective Rates, with Lookback no CRC	\$28.00	\$29.55	\$31.34	\$26.42	\$26.97	\$25.49	\$22.84	\$15.05	\$11.14	\$17.13	\$21.21	\$28.28	\$21.23	
BP-12 Effective Rates, Tier 1 with Lookback	\$31.82	\$9.06	\$12.57	\$12.72	\$19.99	\$25.52	\$38.08	\$16.43	\$22.42	\$29.90	\$27.57	\$26.17	\$24.34	
	13.6%	-69.3%	-59.9%	-51.8%	-25.9%	0.1%	66.7%	9.2%	101.3%	74.5%	30.0%	-7.5%	14.7%	

SUMMARY TOTAL	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
PF-10 Effective Rates with all credits	\$27.60	\$28.85	\$30.78	\$25.83	\$26.25	\$24.76	\$22.47	\$14.82	\$10.94	\$16.96	\$21.02	\$28.03	\$20.90
BP-12 Effective Rates, Tier 1 and Tier 2	\$31.82	\$9.07	\$12.58	\$12.73	\$20.00	\$25.53	\$38.08	\$16.43	\$22.42	\$29.91	\$27.57	\$26.18	\$24.34
	15.3%	-68.6%	-59.1%	-50.7%	-23.8%	3.1%	69.5%	10.9%	104.9%	76.4%	31.2%	-6.6%	16.5%

CUMULATIVE CASH FLOW	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
WP-10 Cash Flow and Cumulative Cash Flow	\$ 242,750	\$ 406,320	\$ 658,396	\$ 779,644	\$ 886,243	\$ 963,184	\$ 1,023,701	\$ 643,228	\$ (86,964)	\$ (405,546)	\$ (397,076)	\$ 0	\$ 1,023,701
BP-12 (TRM) Cash Flow and Cumulative Cash Flow	\$ 268,451	\$ (41,080)	\$ (337,580)	\$ (619,573)	\$ (704,821)	\$ (681,502)	\$ (154,495)	\$ (646,318)	\$ (786,493)	\$ (339,070)	\$ (101,689)	\$ (0)	\$ 268,451

SELF SUPPLY COST (Not paid to BPA)	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Annual
Self Supply Above HWM (\$/MWh)	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32	\$46.32
New Resources (Self Supply) Cost	\$14,819	\$14,361	\$14,819	\$14,819	\$13,863	\$14,799	\$14,341	\$14,819	\$14,341	\$14,819	\$14,819	\$14,341	\$174,956

**Disclaimer: Bonneville Power Administration provides this spreadsheet as a tool to estimate the impact of power rate proposals on individual customers. BPA makes no commitment to the accuracy of this information and intends that this spreadsheet be used solely for illustrative purposes. All data, formulas, and other content are subject to change at any time**

Notes:  
\* Above-RHWM Load Shaping Amounts are included in Tier 1 charges and loads.  
\*\*Resource related charges include Grandfathered GMS, Resource Support Services (DFS, FORS, and SCS), and Transmission Scheduling Services (TSS and TCMS)

### BPA Errata - Irrigation Discount Projection

**Irrigation Rate Discount**

IRD Percentage.....	37.47%
Total Irrigation \$Load (MWh).....	1,881,605
RT1SC.....	6,998
Irrigation Load Weighted LDD.....	4.90%

Annual TRM Rates (\$000/percent)

Composite	\$ 23,929
Non-Slice	\$ (5,421)

	2012	2013
Hours.....	8784	8760
IRD TOCA.....	3.06099%	3.06938%
Composite Revenue.....	\$ 73,245,872	\$ 73,446,634
Non-Slice Revenue.....	\$ (16,592,507)	\$ (16,637,986)
Load Shaping Revenue.....	\$ (232,882)	\$ (223,434)
<b>Total after LDD.....</b>	<b>\$ 53,655,880</b>	<b>\$ 53,812,539</b>

BP-12 IRD Rate..... **10.70**

## BPA Errata - Irrigation Discount Projection as Revised

### Irrigation Rate Discount

<b>IRD Percentage</b> .....	37.06%
<b>Total Irrigation \$Load (MWh)</b> .....	1,881,605
<b>RT1SC</b> .....	6,998
<b>Irrigation Load Weighted LDD</b> .....	4.90%

### Annual TRM Rates (\$000/percent)

Composite	\$ 23,929
Non-Slice	\$ (5,421)

	2012	2013
<b>Hours</b> .....	8784	8760
<b>IRD TOCA</b> .....	3.06099%	3.06938%
<b>Composite Revenue</b> .....	\$ 73,245,872	\$ 73,446,634
<b>Non-Slice Revenue</b> .....	\$ (16,592,507)	\$ (16,637,986)
<b>Load Shaping Revenue</b> .....	\$ (232,882)	\$ (223,434)
<b>Total after LDD</b> .....	\$ 53,655,880	\$ 53,812,539

<b>BP-12 IRD Rate</b> .....	10.58
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## NIU - Load Following Irrigation Discount Projection

### Irrigation Rate Discount

IRD Percentage.....	38.10%
Total Irrigation \$Load (MWh).....	1,097,288
RT1SC.....	6,998
Irrigation Load Weighted LDD.....	6.55%

### Annual TRM Rates (\$000/percent)

Composite	\$ 23,929
Non-Slice	\$ (5,421)

	2012	2013
Hours.....	8784	8760
IRD TOCA.....	1.78507%	1.78996%
Composite Revenue.....	\$ 42,714,615	\$ 42,831,627
Non-Slice Revenue.....	\$ (9,676,211)	\$ (9,702,718)
Load Shaping Revenue.....	\$ (165,206)	\$ (159,628)
Total after LDD.....	\$ 30,720,003	\$ 30,809,792

BP-12 IRD Rate.....	10.68
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## NIU - Slice/Block Irrigation Discount Projection

### Irrigation Rate Discount

IRD Percentage.....	36.06%
Total Irrigation \$Load (MWh).....	784,316
RTISC.....	6,998
Irrigation Load Weighted LDD.....	3.42%

### Annual TRM Rates (\$000/percent)

Composite	\$ 23,929
Non-Slice	\$ (5,421)

	2012	2013
Hours.....	8784	8760
IRD TOCA.....	1.27592%	1.27942%
Composite Revenue.....	\$ 30,531,257	\$ 30,615,008
Non-Slice Revenue.....	\$ (6,916,295)	\$ (6,935,268)
Load Shaping Revenue.....	\$ (67,702)	\$ (63,833)
<b>Total after LDD.....</b>	<b>\$ 22,741,943</b>	<b>\$ 22,808,243</b>

BP-12 IRD Rate.....	10.47
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