

LAW OFFICES OF

**RACINE OLSON NYE BUDGE & BAILEY
CHARTERED**

101 SOUTH CAPITOL BOULEVARD
SUITE 208
BOISE, IDAHO 83702

TELEPHONE (208) 395-0011
FACSIMILE (208) 433-0167

WWW.RACINELAW.NET

SENDER'S E-MAIL ADDRESS:
ELO@RACINELAW.NET

W. MARCUS W. NYE
RANDALL C. BUDGE
JOHN A. BAILEY, JR.
JOHN R. GOODELL
JOHN B. INGELSTROM
DANIEL C. GREEN
BRENT O. ROCHE
KIRK B. HADLEY
FRED J. LEWIS
MITCHELL W. BROWN
ERIC L. OLSEN
CONRAD J. AIKEN
RICHARD A. HEARN, M.D.
DAVID E. ALEXANDER
LANE V. ERICKSON
PATRICK N. GEORGE
SCOTT J. SMITH
STEPHEN J. MUHONEN
BRENT L. WHITING
JUSTIN R. ELLIS
JOSHUA D. JOHNSON
JONATHAN S. BYINGTON
DAVE BAGLEY
CAROL TIPPI VOLYN
THOMAS J. BUDGE
CANDICE M. MCHUGH
JONATHAN M. VOLYN
MARK A. SHAFFER
JASON E. FLAIG
FERRELL S. RYAN

POCATELLO OFFICE
201 EAST CENTER STREET
POST OFFICE BOX 1391
POCATELLO, IDAHO 83204
TELEPHONE: (208) 232-6101
FACSIMILE: (208) 232-6109

IDAHO FALLS OFFICE
477 SHOUP AVENUE
SUITE 203A
IDAHO FALLS, ID 83402
TELEPHONE: (208) 528-6101
FACSIMILE: (208) 528-6109

COEUR D'ALENE OFFICE
250 NORTHWEST
BOULEVARD, SUITE 106A
COEUR D'ALENE, IDAHO 83814
TELEPHONE: (208) 765-6888

ALL OFFICES TOLL FREE
(877) 232-6101

LOUIS F. RACINE (1917-2005)
WILLIAM D. OLSON, OF
COUNSEL

October 28, 2010

Jean D. Jewell
Commission Secretary
Idaho Public Utilities Commission
472 W. Washington
Boise, ID 83702

Re: Case No. PAC-E-10-7

Dear Ms. Jewell:

Please find enclosed for filing an original and nine copies of the following filed on behalf of Monsanto Company:

1. Errata Sheet to Direct Testimony of Mark T. Widmer;
2. Confidential Corrected Direct Testimony of Mark T. Widmer;
3. Public Corrected Direct Testimony of Mark T. Widmer; and
4. Proof of Service.

The Confidential Testimony will only be served on parties who signed the Confidentiality Agreement. Also enclosed is a CD containing an electronic copy of these new filings.

Thank you for your assistance.

Sincerely,

Randall C. Budge
RANDALL C. BUDGE

RCB:bb
Enclosures

c: Service List

RECEIVED
2010 NOV 22 AM 9:34
IDAHO PUBLIC UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF)
ROCKY MOUNTAIN POWER FOR)
APPROVAL OF A GENERAL RATE)
INCREASE OF)
)
)
)
)
)

DOCKET NO. ID PAC-E-10-07

RECEIVED
2010 NOV 22 AM 9:35
IDAHO PUBLIC
UTILITIES COMMISSION

**ERRATA SHEET TO
DIRECT TESTIMONY OF
MARK T. WIDMER
ON BEHALF OF
MONSANTO**

This Errata Sheet is provided to set forth the corrections listed below to the Direct Testimony of Monsanto Company Witness Mark Widmer. The Corrected Direct Testimony of Witness Widmer is filed herewith to amend and supersede his Direct Testimony filed November 1, 2010 and reflect the corrections, to wit:

Page 3 – Table 1

- Black Hills Shaping adjustment -1,321,425 should be changed to -1,293,489 and -78,400 should be changed to -76,743
- Total Adjustments of -47,374,707 should be changed to -47,346,771 and -2,565,628 should be changed to -2,563,970
- Est. Allowed of 1,022,326,607 should be changed to 1,022,354,544 and 60,899,751 should be changed to 60,901,409

Page 5 line 2 \$0.38 should be changed to \$0.35

Page 5 line 7 \$0.16 should be changed to \$0.14

Page 5 line 15 \$0.65 should be changed to \$0.14

Page 7 line 12 \$0.02 should be changed to \$0.20

Page 18 line 3 3.1 should be changed to 2.69

Page 18 line 4 7 should be changed to 6

Page 24 line 7 5 should be changed to 4

Page 24 line 8 5 should be changed to 4

Page 24 line 10 4 should be changed to 3

Page 26 lines 10 and 19 390 should be changed to 395

Page 26 line 16 369.6 should be changed to 374.3

Page 26 line 17 362.5 should be changed to 367.2

Page 27 line 16 strike are not economic and

RECEIVED
2010 NOV 22 AM 9:35
IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF)
ROCKY MOUNTAIN POWER FOR)
APPROVAL OF A GENERAL RATE)
INCREASE OF)
)
)
)
)
)

DOCKET NO. ID PAC-E-10-07

RECEIVED
2010 NOV 22 AM 9:37
IDAHO PUBLIC
UTILITIES COMMISSION

CORRECTED
DIRECT TESTIMONY OF
MARK T. WIDMER
ON BEHALF OF
MONSANTO

November 1, 2010

1	TABLE OF CONTENTS	PAGE
2	I. INTRODUCTION AND QUALIFICATIONS	1
3		
4	II. PURPOSE OF TESTIMONY AND SUMMARY OF ADJUSTMENTS	2
5		
6	III. DETAILED ADJUSTMENTS	9
7		
8	Adjustment 1 APS Supplemental	10
9	Adjustment 2 Wind Integration Costs	11
10	Adjustment 2a OATT Wind Integration Costs	13
11	Adjustment 2b Balancing Wind Integration Costs	15
12	Adjustment 3 Non-Firm Transmission	17
13	Adjustment 4 Dunlap Reserve Requirement	19
14	Adjustment 5 Reserve Shutdowns	19
15	Adjustment 6 Top of World	22
16	Adjustment 6a Top of World Incremental Wind Integration	22
17	Adjustment 7 Cal ISO	22
18	Adjustment 8 Colstrip Planned Outages	24
19	Adjustment 9 Energy Gateway Transmission	26
20	Adjustment 10 Cholla 4 Capacity	26
21	Adjustment 11 Morgan Stanley Calls Premiums	26
22	Adjustment 12 Bear River Hydro Normalization	27
23	Adjustment 13 Black Hills Shaping	30
24	Adjustment 14 Mona Market	32
25	Adjustment 15 Naughton 3 Outage	34
26		
27		
28	Appendix A	
29	Exhibit 228 (MW-1)	
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		

1 **I. INTRODUCTION AND QUALIFICATIONS**

2 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 A. My name is Mark T. Widmer and my business address is 27388 S.W. Ladd Hill Road,
4 Sherwood, Oregon 97140.

5
6 **Q. PLEASE STATE YOUR OCCUPATION, EMPLOYMENT, AND ON WHOSE
7 BEHALF YOU ARE TESTIFYING.**

8 A. I am a utility regulatory consultant and Principal of Northwest Energy Consulting, LLC
9 (“NWECC”). I am appearing on behalf of Monsanto.
10
11

12 **Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND APPEARANCES.**

13 A. With NWECC, I provide consulting services related to electric utility system operations,
14 energy cost recovery issues, revenue requirements, and avoided cost pricing for
15 qualifying facilities. Since forming NWECC, I have provided testimony in dockets
16 regarding recovery of net power costs through general rate cases and power cost
17 adjustment mechanisms and avoided cost methodologies in Wyoming and net power
18 costs and the prudence of resource acquisitions in Washington. Prior to forming NWECC,
19 I was employed by PacifiCorp. While employed by PacifiCorp, I participated in and filed
20 testimony on power cost issues in numerous dockets in Wyoming, Oregon, Utah,
21 Washington, Idaho, and California jurisdictions over a 10 plus year period. At the time
22 of my departure from PacifiCorp, I was the Director of Net Power Costs. My full
23 qualifications and appearances are provided in Exhibit Monsanto 228 (MW-1).

1 **II. PURPOSE OF TESTIMONY AND SUMMARY OF ADJUSTMENTS**

2 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

3 A. My testimony addresses PacifiCorp's Generation and Regulation Initiatives Decision
4 ("GRID") model which was used to calculate normalized Net Power Costs ("NPC") for
5 the forecast test period ending December 31, 2010.
6

7 **Q. PLEASE SUMMARIZE YOUR TESTIMONY.**

8 A. My testimony presents fifteen NPC adjustments totaling \$47.37 million total Company
9 and \$2.57 million Idaho. As discussed in my following testimony, those adjustments are
10 made to reflect realistic operation of PacifiCorp's system, match costs with benefits,
11 make corrections and reflect reasonable results. My adjustments are summarized on
12 Table 1 below and subsequently explained in more detail in the remainder of my
13 testimony.

1

Table 1 Summary of Recommended Adjustments - \$			
	Total Company	Primary Recommendation Idaho Est.	Secondary Recommendations Idaho Est.
GRID (Net Variable Power Cost Issues)			
PacifiCorp Request NPC	1,069,701,315	63,465,379	
ADJUSTMENTS			
1 APS Supplemental (Coal +Other)	-1,942,838	-115,269	
2 Wind Integration Costs	-34,187,931	-1,883,242	
2a OATT Wind integration Costs	-6,361,994		-350,450
2b Balancing Wind Integration Costs	-2,629,076		-144,823
3 Non-Firm Transmission	-2,432,988	-144,349	
4 Dunlap Reserve Requirement	127,222	7,548	
5 Reserve Shutdowns	-807,546	-47,912	
6 Top of World Wind	1,550,033	91,963	
6a Top of World Incremental Wind Integration	285,266		15,714
7 Cal ISO	-4,041,991	-222,653	
8 Colstrip Planned Outages	-258,678	-15,347	
9 Energy Gateway Transmission	3,291,265	195,271	
10 Cholla 4 Capacity	-1,113,498	-66,064	
11 Morgan Stanley Call Premiums	-3,057,000	-168,395	
12 Bear River Hydro Normalization	-2,181,474	-129,427	
13 Black Hills Shaping	-1,293,489	-76,743	
14 Mona Market	-438,529	-26,018	
15 Naughton 3 Outage Allocation True-UP	-559,329	-33,185 69,851	
Total Adjustments Primary Recommendation	-47,346,771	-2,563,970	
Est. Allowed - NPC Primary Recommendation	1,022,354,544	60,901,409	
Est. Idaho Jurisdiction			
SE: 6.3575%			
SG: 5.5085%			

2

3

4

Adjustment 1. APS SUPPLEMENTAL OPTION

5

6

7

The Company has an option to purchase supplemental energy offered pursuant to the Long Term Power Transaction Agreement with Arizona Public Service ("APS"). While the option is continually exercised during actual operations, it is uneconomic as

1 modeled in GRID. Since the purchase is optional and uneconomic it should be excluded
2 from NPC. This adjustment reduces NPC by \$0.12 million on an Idaho basis.

3
4 **Adjustment 2. WIND INTEGRATION COSTS**

5 The Company used the wind integration rate of \$6.50 per MWh that was adopted by the
6 Commission for avoided cost rates for qualifying facility contracts to calculate wind
7 integration costs. This rate has no basis on the Company's actual wind integration costs
8 and the Company has therefore, not met its burden of proof regarding recovery of wind
9 integration costs. Consequently, I recommend that the Commission reject recovery of
10 wind integration costs using the \$6.50 per MWh rate and recommend that wind
11 integration costs be recovered through the Company's ECAM as it is the best solution to
12 recovering actual wind integration costs. This adjustment reduces NPC by \$1.88 million
13 on an Idaho basis. I also recommend that the Commission adopt the premise of my
14 secondary adjustment 2a OATT Wind Integrations Costs, so that the Company not be
15 allowed to recover wholesale wheeling customer wind integration costs from retail
16 customers through the ECAM. If the Commission does not adopt my proposed
17 recommendation, my secondary recommendation is to adopt the following adjustments
18 2a OATT Customer Wind Integration Costs and 2b Balancing Wind Integration Costs.

19
20 **Adjustment 2a. OATT CUSTOMER WIND INTEGRATION COST**

21 The Company included wholesale wheeling customer wind integration costs in
22 NPC because the Company has failed to request an adjustment to their OATT so that
23 these costs can be recovered from wholesale wheeling customers. These costs are not the

1 responsibility of Idaho customers and should be removed from NPC. This adjustment
2 reduces NPC by \$0.35 million on an Idaho basis.

3
4 **Adjustment 2b. BALANCING WIND INTEGRATION COSTS**

5 The Company double counted wind integration balancing costs during the period
6 January 2010 through April 2010. This adjustment removes the double count and lowers
7 NPC by \$0.14 million on an Idaho basis.

8
9 **Adjustment 3. NON-FIRM TRANSMISSION**

10 In actual operations the Company utilizes a significant amount of non-firm
11 transmission to use of assets included in rates more efficiently in the system balancing
12 and optimization process. However, non-firm transmission was excluded from NPC,
13 thereby producing a suboptimal dispatch of the system and higher net power costs. I
14 recommend that non-firm transmission be included in GRID to match costs and benefits.
15 This adjustment reduces NPC by \$0.14 million on an Idaho basis.

16
17 **Adjustment 4. DUNLAP RESERVE REQUIREMENT**

18 This adjustment incorporates the costs of carrying operating reserves for Dunlap,
19 which were omitted from the original filing and increases NPC by \$0.01 million on an
20 Idaho basis.

21
22 **Adjustment 5. RESERVE SHUTDOWN EFOR COMPONENT**

23 The Company's inclusion of reserve shutdowns in the GRID forced outage rate
24 calculation input causes an overstatement of generation lost due to forced outages

1 because the calculation is inconsistent with how GRID calculates generation lost due to
2 forced outages. I recommend exclusion of reserve shutdowns from the forced outage rate
3 calculation for all plants except for natural gas peaker units. This adjustment reduces
4 NPC by \$0.05 million on an Idaho basis.

5
6 **Adjustment 6. TOP OF WORLD WIND**

7 During the discovery process the Company informed Monsanto that the expected
8 online date for the Top of the World wind project had been moved forward from
9 November 1, 2010 to October 1, 2010. This adjustment includes the new online date and
10 increases NPC by \$0.09 million on an Idaho basis.

11
12 **Adjustment 6a. TOP OF WORLD INCREMENTAL WIND INTEGRATION**

13 If the Commission does not adopt my primary recommendation to recover wind
14 integration costs through the ECAM, this adjustment includes incremental integration
15 costs associated with moving the expected in service date from November 1, 2010 to
16 October 1, 2010.

17
18 **Adjustment 7. CAL ISO EXPENSES**

19 The filing includes a full year estimate of Cal ISO wheeling and service fees.
20 However, the filing does not include any transactions that would incur CAL ISO fees
21 beyond May 3, 2010. Accordingly, I recommend disallowance of all Cal ISO fees for the
22 period May 4, 2010 through December 31, 2010. I also recommend that actual Cal ISO
23 fees be included for the period prior to May 4, 2010 to match costs with the actual

1 wholesale transactions included in the filing. This adjustment reduces NPC by \$.22
2 million on an Idaho basis.

3
4 **Adjustment 8. COLSTRIP PLANNED OUTAGES**

5 This adjustment moves the planned outage starting dates for Colstrip 3 and Colstrip 4
6 from September to May to better optimize the Company's system.

7 The revised planned outage dates reduce NPC on an Idaho basis by \$0.02 million.

8
9 **Adjustment 9. ENERGY GATEWAY TRANSMISSION**

10 This adjustment removes the Energy Gateway transmission project from NPC to be
11 consistent with Mr. Peseau's Energy Gateway transmission adjustment and increases NPC
12 by \$0.20 million on an Idaho basis.

13
14 **Adjustment 10. CHOLLA 4 CAPACITY**

15 The Company's modeling understates Cholla 4 capacity. My adjustment corrects the
16 capacity and reduces NPC by \$0.07 million on an Idaho basis.

17
18 **Adjustment 11. MORGAN STANLEY CALL PREMIUMS**

19 The Company's filing includes two call option purchase power contracts that are
20 uneconomic. This adjustment removes both contracts and lowers NPC by \$0.17 million
21 on an Idaho basis.

1 **Adjustment 12. BEAR RIVER HYDRO NORMALIZATION**

2 The Bear River historical record was adjusted by the Company to remove flood
3 control years, which are years when surplus water was released from Bear Lake. The
4 Company believes the adjustment is reasonable because the region is currently impacted
5 by a long-term drought and a low water level at Bear Lake. This is one-sided because it
6 is different than the normalized methodology used to normalize all other hydro resources
7 and is not appropriate for normalized ratemaking. I recommend that the flood control
8 years excluded from NPC be included in NPC to be consistent with the modeling of other
9 hydro resources. My recommendation reduces the NPC by \$0.13 million on an Idaho
10 basis.

11
12 **Adjustment 13. Black Hills Sales Shaping**

13 The Company bases its modeling of the Black Hills wholesale sales on the faulty
14 assumption that Black Hills will dispatch the contract during the highest costs hours.
15 Historical dispatch of the contract demonstrates that this is not the case. I recommend
16 that the contract be dispatched based on a four-year average of historical results. This
17 adjustment reduces NPC by \$0.08 million on an Idaho basis.

18
19 **Adjustment 14. MONA MARKET**

20 The Company limited the size of the Mona wholesale market, allegedly based on
21 trading experience of their Front Office. Historical information shows that the Mona
22 market was significantly undersized. I recommend that the size of the Mona market be
23 corrected based on a four-year average of actual information. This adjustment reduces
24 NPC by \$0.03 million on an Idaho basis.

1
2 **Adjustment 15. NAUGHTON 3 OUTAGE**

3 The Company collected liquidated damage payments from its contractor Siemens
4 for failure to complete a contract on schedule due to poor performance. The Company
5 seeks to recover the cost of this outage again by including it in GRID planned outage
6 inputs. Accordingly, I recommend that the planned outage be removed from GRID. This
7 adjustment removes the outage and reduces NPC by \$0.03 million on an Idaho basis.
8

9 Finally, in response to Monsanto data request 2.33 the Company stated:

10 Prior to its rebuttal the Company anticipates additional changes to various
11 components of the net power costs, including but not limited to the new Official
12 Forward Price Curve and new short-term firm electricity and natural gas
13 transactions.
14

15 This very late update does not provide the Parties adequate time to review the
16 significant amount of data tied to the stated update. Therefore, I recommend that the
17 Commission reject all Company proposed rebuttal updates to NPC except corrections
18 related to the original filing so that the Parties other than the Company are not
19 disadvantaged by the late update.
20

21 **III. DETAILED ADJUSTMENTS**

22 **Q. BEFORE YOU DISCUSS YOUR ADJUSTMENTS IN DETAIL, PLEASE**
23 **EXPLAIN NPC AND ITS IMPORTANCE.**

24 A. NPC is defined as the sum of purchased power expense, wheeling expense and fuel
25 expense less wholesale sales revenues. Review and determination of the appropriate
26 NPC is very important because it represents one of the Company's single largest revenue

1 requirement components and establishes the ECAM baseline. NPC is calculated by the
2 Company's GRID production dispatch model.

3
4 **Adjustment 1. ARIZONA PUBLIC SERVICE ("APS") SUPPLEMENTAL**
5 **ENERGY**

6 **Q. PLEASE EXPLAIN THE APS SUPPLEMENTAL ADJUSTMENT.**

7 A. Pursuant to the terms of the Long-Term Power Transactions Agreement between APS
8 and PacifiCorp, APS is required to offer PacifiCorp 219 GWH of Supplemental Coal
9 Energy and 876 GWH of Other Supplemental Energy through October 31, 2020, when
10 the contract expires. The Company has the option but not the requirement to purchase
11 either the Supplemental coal or Other Supplemental energy or both at prices offered by
12 APS for each product.

13
14 **Q. IS THE CONTRACT ECONOMIC AS MODELED IN GRID?**

15 A. No. Both the Other Supplemental and the Supplemental Coal components are modeled
16 uneconomically in GRID.

17
18 **Q. HOW DID YOU DETERMINE THE CONTRACT WAS UNECONOMIC?**

19 A. I ran the GRID model without the Supplemental Coal and Other Supplemental energy.
20 The runs reduced NPC by approximately \$1.95 million total Company. The contract is
21 therefore uneconomic for customers as modeled by the Company and should be excluded
22 from NPC. This adjustment reduces the NPC by \$0.12 million on an Idaho basis.

1 **Q. HAS THE COMPANY AGREED TO THIS METHODOLOGY IN OTHER**
2 **JURISDICTIONS?**

3 **A.** Yes. In the stipulation for Oregon Docket UE 216, the Company agreed to model the
4 APS Supplemental Coal and Other option contract only when economic for future filings.
5

6 **Adjustment 2. WIND INTEGRATION COSTS**

7 **Q. HAS THE COMPANY MET ITS BURDEN OF PROOF ON WIND**
8 **INTEGRATION COSTS?**

9 **A.** No. While the Company has done numerous forecasts of wind integration costs over the
10 last several years, which have varied from a little over \$1 per MWH to approximately \$9
11 per MWh for 2011 in a recent draft study, they still cannot tell us what their actual wind
12 integration costs are. In WIEC Data Request 5.6 from Wyoming Docket No. 20000-352-
13 EP-09 the Company was asked to provide the actual reserve intra-hour reserve
14 requirement for wind generation located within their control area. In response, the
15 Company stated:

16 The Company objects to this question on the basis that it is overly burdensome
17 and would require the Company to perform analysis not previously performed.
18 Notwithstanding this objection, the Company states as follows.
19

20 The Company holds reserves to maintain reliability of its system in accordance
21 with standards set by the Western Electricity Coordinating Council. Reserves
22 held are not differentiated such that the Company can identify the intra-hour
23 reserve requirement isolated for wind generation.
24

25 Without knowing what the Company's actual costs are it is very difficult to determine the
26 reasonableness of Company's requested recovery of \$34.2 million for wind integration
27 costs.
28

1 **Q. IS THE COMPANY'S PROPOSED USE OF THE \$6.50 PER MWH COST OF**
2 **WIND INTEGRATION RATE APPROVED BY THE IDAHO COMMISSION IN**
3 **CASE NO. PAC NO.-E-09-07, A REASONABLE SOLUTION TO THE**
4 **COMPANY'S LACK OF VERIFIABLE INFORMATION?**

5 A. It is a solution, but it is not the best solution, because the adopted wind integration rate is
6 not based on the Company's system costs. The rate was adopted specifically to be used
7 in the determination of avoided cost rates. To date the Company has not entered any
8 Idaho based wind qualifying facility contracts, so the adoption of the rate for avoided
9 costs has not placed customers at risk of paying too much. However, requesting recovery
10 of over \$34 million for wind integration costs in this case based on the \$6.50 per MWh
11 rate is a different matter as it places customers at risk of paying too much.

12
13 **Q. WHAT IS YOUR RECOMMENDATION?**

14 A. The Commission should reject the Company's request for recovery of wind integration
15 costs using the \$6.50 per MWh rate approved for avoided cost rates because their burden
16 of proof has not been met. Due to the significant size of these costs, recovery should
17 occur through the ECAM. Only this way can we be assured that actual wind integration
18 costs is recovered. This adjustment reduces NPC by \$1.88 million on an Idaho basis. I
19 also recommend that the Commission adopt the premise of my secondary adjustment 2a
20 OATT Wind Integrations Costs, so that the Company not be allowed to recover
21 wholesale wheeling customer wind integration costs from retail customers through the
22 ECAM.

23
24 **Q. DO YOU HAVE A SECONDARY RECOMMENDATION?**

1 A. Yes. If the Commission rejects my recommendation for this adjustment I recommend
2 that the Commission accept my secondary proposed adjustments 2a OATT Wind
3 Integration Costs and 2b. Balancing Wind Integration Costs, which are discussed in my
4 following testimony.
5

6 **Adjustment 2a. OPEN ACCESS TRANSMISSION TARIFF (OATT) - WIND**
7 **INTEGRATION**

8 **Q. DOES THE COMPANY'S OATT TARIFF INCLUDE A CHARGE FOR WIND**
9 **INTEGRATION EXPENSES FOR WHOLESALE TRANSMISSION**
10 **CUSTOMERS?**

11 A. No. Despite being aware of wind integration expenses for over six years, based on the
12 inclusion of such expenses in its 2004 IRP, the Company has not made a filing with the
13 Federal Energy Regulatory Commission requesting inclusion of such expenses in its
14 OATT. So, the Company is attempting to recover these costs from retail customers.
15

16 **Q. SHOULD RETAIL CUSTOMERS BE REQUIRED TO PAY FOR THESE**
17 **COSTS?**

18 A. Of course not. Recovery of these costs from OATT customers is the Company's
19 responsibility and they have had over six years to make a filing with FERC that would
20 allow them to recover such costs. Retail customers should not be burdened with these
21 costs due to the Company's failure to make such a filing.
22

1 **Q. HAS THE COMPANY INDICATED IF AND WHEN THEY PLAN TO MAKE A**
2 **FILING TO MODIFY ITS OATT TO INCLUDE CHARGES FOR WIND**
3 **INTEGRATION SERVICES TO NON-OWNED WIND FACILITIES?**

4 A. Yes. In the stipulation for Oregon Docket UE 216 the Company agreed to make a filing
5 before the Federal Energy Regulatory Commission in June 2011. While the Company
6 has finally decided to make this filing there is nothing that prevented them from making
7 the filing at a much earlier date.

8
9 **Q. ARE WIND INTEGRATION COSTS INCLUDED IN OTHER TRANSMISSION**
10 **PROVIDERS OATT?**

11 A. Yes. As a matter of fact, the Company pays Bonneville Power Administration (BPA) for
12 wind integration costs associated with the Goodnoe and Leaning Juniper wind projects
13 and has included those costs in the wheeling expense.

14
15 **Q. HAS FERC PREVIOUSLY ADDRESSED MODIFICATION OF THE OATT?**

16 A. Yes. In Docket No. ER09-1314-0000, the FERC ruled that applicant, Northwestern
17 Energy's proposal related to this issue was not superior to its proforma OATT tariff. The
18 FERC stated that:

19 Rather than proposing a generator regulation charge to recover capacity costs of
20 holding additional reserves necessary to meet generator imbalances,
21 NorthWestern's proposal seeks to eliminate any obligation under its Tariff to
22 offer such service in the first instance (at least with respect to intermittent
23 renewable generators exporting energy out of NorthWestern's balancing authority
24 area). Accordingly, we find that NorthWestern's proposal is neither consistent
25 with nor superior to the proforma Tariff. Our determination is without prejudice
26 to NorthWestern proposing to remedy the cost allocation issues discussed in this
27 proceeding, consistent with the guidance set forth above.
28

1 Order Rejecting Proposed Tariff Revisions, FERC Docket No. ER09-1314-0000, Order
2 No. 20091110 at paragraph 27 (November 10, 2009). The FERC also stated:

3 In its filing, NorthWestern describes a “gap” between its obligations as a
4 balancing authority and its opportunity to recover the costs associated with these
5 obligations under its Tariff. NorthWestern asserts that its Tariff does not contain
6 a mechanism that allows it to recover generator regulation service costs associated
7 with transmission used to export energy from NorthWestern’s system, which
8 NorthWestern must incur to meet reliability standards. Moreover, NorthWestern
9 contends that its native load customers should not be required to subsidize the
10 costs of providing generator regulation service to those generators that export
11 energy from NorthWestern’s system. To the extent that NorthWestern is not
12 currently recovering the costs of providing generator regulation service to
13 exporting generators, we agree that a mechanism allowing it to recover those
14 costs is appropriate.
15

16 FERC clearly does not believe that retail customers should pay for the costs of wholesale
17 customers either and suggested a mechanism should be allowed to solve the problem. In
18 the interim, retail customers should not be required to pay for these costs. Accordingly, I
19 recommend that such wind integration costs be excluded from NPC because the
20 Company has had ample opportunity to request modification of its OATT to recover
21 these costs from the parties that caused the Company to incur these expenses and retail
22 customers should not be burdened for the Company’s failure to act. This adjustment
23 reduces NPC by \$0.35 million on an Idaho basis.
24

25 **Adjustment 2b. WIND INTEGRATION COSTS - BALANCING**

26 **Q. PLEASE EXPLAIN THE COMPONENTS OF THE WIND INTEGRATION**
27 **COSTS.**

28 **A.** The wind integration cost is comprised of Inter-hour and Intra-hour costs. Inter-hour cost
29 is the balancing component and consists of pre-scheduling and hour-ahead balancing.

1 Intra-hour costs are the costs carrying load following and regulation reserves for the
2 variability of wind generation. This adjustment focuses on the balancing component.
3

4 **Q PLEASE EXPLAIN HOW THE COMPANY BALANCES ITS SYSTEM FOR**
5 **WIND INTEGRATION.**

6 A. The Company has a variety of options for balancing. In order of most frequent use
7 balancing is accomplished through hourly firm wholesale transactions, re-dispatch of
8 wholesale contracts with hourly flexibility, re-dispatch of generation resources, hourly
9 non-firm wholesale sales transactions and wind curtailment.
10

11 **Q DOES THE COMPANY'S FILING INCLUDE A DOUBLE COUNT OF WIND**
12 **INTEGRATION BALANCING COSTS?**

13 A. Yes. The balancing cost component of wind integration is double counted because the
14 Company's filing included actual short-term firm transactions for the period January 1,
15 2010 through May 4, 2010, which includes actual hourly firm wholesale transactions
16 used for wind integration balancing and the Company's separately calculated wind
17 integration costs using the \$6.50 per MWh wind integration rate. This leaves the
18 question of how to allocate part of the \$6.50 per MWh rate to balancing to determine the
19 amount of the double count.
20

21 **Q HOW SHOULD A PORTION OF THE \$6.50 MWH RATE BE ALLOCATED TO**
22 **BALANCING?**

23 A. The method should be straight forward and based on Company data. With that
24 clarification I believe we should look to the Company's last completed IRP to determine

1 an allocation. In that IRP the Company calculated a total wind integration cost of \$6.92
2 per MWh consisting of \$2.09 per MWh for balancing and \$4.83 for intra-hour
3 integration. Using this information the balancing component for the \$6.50 per MWh rate
4 can be calculated by dividing \$2.09 per MWh by \$6.92 per MWh and multiplying that
5 result (30.2%) times \$6.50 per MWh. This produces a double count of \$1.96 per MWh.
6

7 **Q. SHOULD THE \$1.96 BE REDUCED FURTHER TO COMPENSATE FOR THE**
8 **PORTION OF BALANCING THAT IS ACCOMPLISHED BY MEANS OTHER**
9 **THAN HOURLY FIRM WHOLESALE SALES TRANSACTIONS INCLUDED IN**
10 **GRID?**

11 A. A further adjustment could be reasonable if the information were available. However,
12 the Company stated that there is no official Company estimate of how much balancing is
13 accomplished through the various means identified above other than to place them in an
14 order of most to least. Since the Company has previously stated that most of its
15 balancing occurs through actual hourly wholesale sales transactions, which are included
16 in GRID, \$1.96 per MWh should be used to remove the double count. This adjustment
17 reduces NPC by \$0.14 million on an Idaho basis.
18

19 **Adjustment 3. NON-FIRM TRANSMISSION**

20 **Q. DO YOU AGREE WITH PACIFICORP'S EXCLUSION OF NON-FIRM**
21 **TRANSMISSION FROM NPC?**

22 A. No. Exclusion of non-firm transmission is not consistent with actual operations and does
23 not provide a match between costs and benefits. If the Company used an immaterial
24 amount of non-firm transmission it may be reasonable to exclude it from normalized

1 results. However, that is not the case. As shown below in Table 2 – PacifiCorp
 2 Transmission Utilization, a substantial amount of non-firm transmission is utilized.
 3 During 2009, non-firm transmission of energy exceeded STF transmission by over 2.69
 4 million MWh or by more than 6 times. It is rather obvious that non-firm transmission is
 5 normally relied upon to balance and optimize the Company’s system.

Table 2			
Pacificorp Transmission Utilization			
Millions MWh /1			
	Non-Firm	STF	Total
2006	1.76	2.86	4.62
2007	0.88	3.66	4.53
2008	9.74	4.09	13.83
2009	3.13	0.44	3.57
4 Year Avg.	3.88	2.76	6.64

6 /1 Excludes Cal ISO, intra bubble and transmission already modeled

7

8 **Q. WHY DOES THE COMPANY UTILIZE NON-FIRM TRANSMISSION?**

9 A. Non-firm transmission is utilized to balance and optimize the Company’s system. This
 10 keeps NPC lower than it would be absent use of non-firm transmission. Lower NPC is
 11 accomplished through more efficient use of generation and transmission assets in concert
 12 with wholesale transactions and creates more benefits (earnings) for the Company and its
 13 shareholders. Since these benefits are derived from assets and expenses already included
 14 in rates, non-firm transmission should be included in NPC to match costs with benefits.

15

16 **Q. HAS THE INCLUSION OF NON-FIRM TRANSMISSION BEEN ADOPTED BY**
 17 **OTHER COMMISSIONS OR BEEN AGREED TO BY THE COMPANY?**

1 A. Yes. Inclusion of non-firm transmission has been adopted in the Company's two largest
2 jurisdictions, Utah and Oregon, The Utah Commission adopted non-firm transmission in
3 Docket No. 07-035-93. More recently, in the stipulation for Oregon Docket UE-216, the
4 Company agreed to include non-firm transmission links and costs in all future filings
5 using a four-year average.
6

7 **Q. WHAT IS YOUR RECOMMENDATION FOR NON-FIRM TRANSMISSION?**

8 A. Non-firm transmission links and costs should be modeled in GRID using the same four-
9 year average used to normalize thermal generation. This will match costs and benefits
10 and thereby allow customers to receive the full benefits of the system they are paying for
11 in rates. The adjustment reduces NPC by \$0.14 million on an Idaho basis.
12

13 **Adjustment 4. DUNLAP RESERVE REQUIREMENT**

14 **Q. PLEASE EXPLAIN THE DUNLAP RESERVE REQUIREMENT ADJUSTMENT.**

15 A. The Company did not model the Dunlap wind project as having an operating reserve
16 requirement. This adjustment includes the operating reserve requirement for Dunlap and
17 increases NPC by \$0.01 million on an Idaho basis.
18

19 **Adjustment 5. RESERVE SHUTDOWNS**

20 **Q. PLEASE DEFINE RESERVE SHUTDOWNS.**

21 A. Reserve shutdown is a state in which a thermal unit was available for service but not
22 electrically connected to the grid for economic reasons.
23

1 **Q. HOW ARE RESERVE SHUTDOWNS USED IN THE COMPANY'S**
2 **CALCULATION OF FORCED OUTAGE RATE INPUTS FOR GRID?**

3 A. The Company's forced outage rate calculation excludes reserve shutdown hours from the
4 denominator. The formula is as follows:

5
$$\text{Forced outage rate} = \frac{\text{total lost hours}}{\text{total possible hours less planned outages}}$$

6 and reserve shutdowns

7 Total lost hours is the sum of forced deratings, forced outages, maintenance deratings,
8 maintenance outages and planned deratings. Total possible hours is the sum of hours in
9 the period multiplied by the each thermal plants maximum dependable capacity.

10

11 **Q. DOES THE COMPANY'S RESERVE SHUTDOWN ADJUSTMENT**
12 **COMPONENT OF THE FORCED OUTAGE RATE CALCULATION PRODUCE**
13 **REASONABLE RESULTS?**

14 A. No. The Company's forced outage rates are inconsistent with GRID's calculation of
15 generation lost due to forced outages because of inconsistencies between the two
16 calculations. In GRID forced outage rates are applied to the units' total possible
17 generation before reserve shutdowns and after planned outages, while the Company's
18 forced outage rates used as an input to GRID are calculated after reserve shutdowns and
19 planned outages. Due to this difference, the Company's proposed forced outage rates
20 produce too much lost generation when used as an input in GRID.

21

22 **Q. HAVE YOU PREPARED AN EXAMPLE TO DEMONSTRATE HOW THE**
23 **OVERSTATEMENT OCCURS?**

1 A. Yes. The overstatement is demonstrated in the following example. Let us assume a
2 generation unit had lost generation of 8,000 MWh due to forced outages, total possible
3 generation of 87,600 MWh, no planned outages, and 3,000 MWh of reserve shutdown.
4 Using the Company's methodology this would produce a forced outage rate of 9.456%
5 $(8,000 / (87,600 - 3,000))$. However, in GRID the 9.456% forced outage rate would
6 produce lost (derated) generation of 8,284 MWh $(87,600 * 9.456\%)$ or 284 more MWh of
7 lost generation. The bottom line is that the Company's formula is not the appropriate
8 formula to calculate forced outage rates that will be used as an input to GRID.

9
10 **Q. WOULD ELIMINATION OF THE RESERVE SHUTDOWN ADJUSTMENT**
11 **FROM THE DENOMINATOR OF THE COMPANY'S FORCED OUTAGE RATE**
12 **CALCULATION MEAN THAT RESERVE SHUTDOWNS ARE EXCLUDED**
13 **FROM NPC?**

14 A. Not at all. The Company's daily screen modeling in GRID specifically identifies when
15 CCCTs are available but are not economic to run and essentially places them on reserve
16 shutdown so they cannot run. Therefore, reserve shutdowns would still be modeled in
17 NPC.

18
19 **Q. WHAT IS YOUR RECOMMENDATION FOR RESERVE SHUTDOWNS?**

20 A. The Company's forced outage rate calculation is inconsistent with the GRID calculation
21 of generation lost due to forced outages and consequently produces too much lost
22 generation. To correct this problem the Company's forced outage rate calculation should
23 be revised by removing the adjustment for reserve shutdowns. This adjustment reduces
24 NPC by approximately \$0.05 million on an Idaho basis.

1 **Adjustment 6. TOP OF WORLD WIND IN SERVICE DATE**

2 **Q. PLEASE EXPLAIN THE TOP OF WORLD WIND ADJUSTMENT.**

3 A. During discovery the Company informed Monsanto that the in-service date for this
4 project was now expected to be October 1, 2010 instead of November 1, 2010. This
5 adjustment moves the in-service date to October 1, 2010 and increases NPC by \$0.09
6 million on an Idaho basis.

7
8 **Adjustment 6a. TOP OF WORLD INCREMENTAL WIND INTEGRATION**

9 **Q. PLEASE EXPLAIN THIS ADJUSTMENT.**

10 A. As I previously discussed in this testimony, my primary recommendation is to remove
11 wind integration costs from the Company's filing so that they are recovered through the
12 ECAM. If my primary recommendation is not adopted this adjustment will include the
13 incremental wind integration costs associated with the one additional month that the Top
14 of World wind project is expected to be in-service during 2010.

15
16 **Adjustment 7. CAL ISO FEES**

17 **Q. DOES THE COMPANY'S FILING INCLUDE A FULL NORMALIZED YEAR OF**
18 **CAL ISO WHEELING AND SERVICE FEES?**

19 A. Yes. NPC includes \$4.7 million of these fees on a total Company basis. However, as
20 explained later in my testimony, a significant portion of these fees are not economic
21 because there are no wholesale transactions that rely on the Cal ISO beyond May 3, 2010.

22
23 **Q. WHY AND WHEN DOES PACIFICORP INCUR THESE FEES?**

1 A. These fees are incurred when the Company uses the Cal ISO system to balance and
2 optimize its system. In other words, the fees are incurred when PacifiCorp believes the
3 associated wholesale transactions produce an incremental benefit above the fees. Some
4 of the fees are related to the Company's strategy to hedge their long position at Four
5 Corners. As explained in Mr. Duvall's testimony from Wyoming Docket No. 20000-
6 352-ER-09:

7 Sales at SP-15 are made to hedge the Company's long position at Four Corners.
8 This occurs when the Company has a desire to hedge its fixed price exposure but
9 the Four Corners Market is illiquid. A portion of these transactions are financial
10 hedges and do not require physical delivery of power. However, if the hedges are
11 physical products, at a time closer to delivery when the Four Corners market
12 becomes more liquid, the Company would sell at Four Corners and buy at SP-15.
13 Alternatively, the Company may wheel power from Four Corners to SP-15 to
14 close the SP-15 physical positions in the hour-ahead market if transmission were
15 available and it is more economical to do so.
16

17 Fees can also be incurred with other balancing and optimizing transactions with the Cal
18 ISO.

19
20 **Q. DOES THE COMPANY'S NPC INCLUDE ANY WHOLESALE TRANSACTIONS**
21 **THAT COULD INCUR CAL ISO FEES AND PRODUCE A MATCHING**
22 **BENEFIT?**

23 A. Yes. The filing included actual STF transactions from January 1, 2010 through May 3,
24 2010. However, after May 3, 2010 the filing did not include any wholesale transactions
25 with the CAL ISO.

26
27 **Q. WHY DOESN'T THE FILING INCLUDE ANY WHOLESALE TRANSACTIONS**
28 **THAT COULD INCUR CAL ISO FEES?**

1 A. Historical records reveal that most of the transactions with the Cal ISO as a counter party
2 are incurred shortly before or on the actual day of delivery. Due to the Company's use of
3 a forecast test period and the fact that the filing was made many months prior to the end
4 of the forecast test year, transactions that would incur Cal ISO wheeling and service fees
5 had not occurred in most months at the time of filing. As a result, NPC includes a full
6 year of Cal ISO costs, but only wholesale transactions that would generate the Cal ISO
7 expense prior to May 4, 2010. For this reason, I recommend that all Cal ISO fees
8 included in the filing for the period May 4, 2010 through December 31, 2010 be excluded
9 from NPC. In addition, I recommend that actual Cal ISO fees be used for the period
10 January 1, 2010 through May 3, 2010 to match with the actual wholesale transactions
11 already included in the filing that caused the actual Cal ISO costs to be incurred. This
12 adjustment reduces NPC by \$0.22 million on an Idaho basis.

13

14 **Adjustment 8. COLSTRIP PLANNED OUTAGES**

15 **Q. PLEASE EXPLAIN HOW THE COMPANY DEVELOPS THERMAL PLANNED**
16 **OUTAGE SCHEDULE INPUTS FOR GRID.**

17 A. The methodology employed by the Company to normalize planned outages uses 48-
18 month average of historical data for the period 2006-2009 to determine the amount of
19 time the plants are on outage. Historically, these outages are scheduled during the spring
20 and fall shoulder months when market prices tend to be lower so that replacement power
21 costs are kept low and ample energy is available from the marketplace to replace the
22 generation on outage. After the Company develops the amount of time the units were on
23 outage it develops a normalized outage schedule based on a variety of factors including

1 market prices, historical outages and the amount of units or MW on outage at a given
2 point in time.

3
4 **Q. DO YOU AGREE WITH THE COMPANY'S NORMALIZED OUTAGE**
5 **SCHEDULE INCLUDED IN GRID?**

6 A. Not completely. The starting point of Colstrip 3 and Colstrip 4 planned outages should
7 be moved from September to May to better optimize the timing of the outages so that
8 NPC would be lower than it would be using the Company's outage schedule.

9
10 **Q DOES YOUR PROPOSED CHANGE TO THE PLANNED OUTAGE SCHEDULE**
11 **RESULT IN AN EXCESSIVE AMOUNT OF CAPACITY ON OUTAGE DURING**
12 **MAY?**

13 A. No. The amount of capacity on outage is within a reasonable range based on a
14 comparison of actual planned outages compared to planned included in the Company's
15 filing.

16
17 **Q. WHAT IS YOUR RECOMMENDATION?**

18 A. I recommend that the Colstrip 3 planned outage be moved from September 18th to May
19 1st and the Colstrip 4 planned outage be moved from September 30th to May 13th. This
20 adjustment reduces proposed NPC by \$0.02 million on an Idaho basis.

21
22 **Adjustment 9. ENERGY GATEWAY TRANSMISSION**

23 **Q. PLEASE EXPLAIN THE GATEWAY TRANSMISSION ADJUSTMENT.**

1 A. This adjustment removes the transmission capacity upgrades associated with the Energy
2 Gateway transmission project included in GRID as part of the adjustment to remove the
3 Energy Gateway project from the Company's filing as recommended by Monsanto
4 witness Dennis Peseau. This adjustment increases NPC by \$0.20 million on an Idaho
5 basis.

6
7 **Adjustment 10. CHOLLA 4 CAPACITY**

8 **Q. PLEASE EXPLAIN HOW CHOLLA 4 CAPACITY WAS MODELED.**

9 A. The Company modeled Cholla 4 capacity at 387MW even though the capacity was
10 upgraded to 395MW not long ago. It appears the reasoning behind modeling the capacity
11 at 387MW is because the Company has 387 MW of firm transmission rights to move
12 Cholla 4 Generation.

13
14 **Q. DO YOU AGREE WITH MODELING CHOLLA 4 AT 387MW?**

15 A. No. Cholla is already derated below 387 MW for weekday and week-end forced outage
16 rates of 5.24% and 7.04%, which respectively produce a derated capacity of 374.3 MW
17 and 367.2 MW for Cholla 4. Since the derated capacity is already below the 387 MW of
18 firm transmission rights it is not necessary to derate the plant for firm transmission rights.
19 Cholla 4 capacity should be modeled at the full 395MW. This adjustment reduces NPC
20 by \$0.07 million on an Idaho basis.

21
22 **Adjustment 11. MORGAN STANLEY CALL PREMIUMS**

23 **Q. PLEASE DESCRIBE THE TWO MORGAN STANLEY CALL OPTION**
24 **CONTRACTS INCLUDED IN THE COMPANY'S FILING.**

1 **A.** The Company entered two call option contracts with Morgan Stanley during November
2 2005 for the period June 1, 2010 through August 31, 2010. Each contract provides the
3 right to call [REDACTED] of firm super-peak product per hour, exercisable only on the
4 “WECC Pre-Scheduling Day” at an additional cost of [REDACTED] per MWh for one contract
5 and [REDACTED] per MWh for the second contract. For this right the Company paid a
6 premium of [REDACTED] for one contract and [REDACTED] for the second contract.
7

8 **Q. WERE EITHER OF THESE CALL CONTRACTS EXERCISED IN THE**
9 **COMPANY’S FILING?**

10 **A.** No. Neither contract was dispatched because they were not economic for the test year.
11

12 **Q. HAS THE COMPANY PREVIOUSLY STATED A POSITION ON THE**
13 **INCLUSION OF CALL OPTION CONTRACTS THAT ARE NOT ECONOMIC?**

14 **A.** Yes. In Oregon Docket UE-191 the Company stated that call option contracts should be
15 removed from NPC if removal lowers NPC. In this case removal of both Morgan Stanley
16 call option contracts lower NPC. For this reason, I recommend removal of Morgan
17 Stanley call option contracts p272153-6 and p272154-7. This adjustment lowers NPC by
18 \$0.17 million on an Idaho basis.
19

20 **Adjustment 12. BEAR RIVER HYDRO NORMALIZATION**

21 **Q. PLEASE EXPLAIN HOW THE COMPANY HISTORICALLY NORMALIZED**
22 **HYDRO GENERATION FOR SMALL HYDRO PROJECTS LIKE BEAR RIVER.**

23 **A.** Small hydro projects generally have no appreciable storage and are operated as run of
24 river projects where stream flow in is equal to the stream flow out. For these small

1 projects, normalized generation is based on an evaluation of 30 years of historical
2 generation capability. Bear River is somewhat different in that it does have some storage
3 capability.

4
5 **Q. HOW DOES THE 30-YEAR NORMALIZATION PROCESS WORK?**

6 A. Thirty years of historical generation are used to develop a median hydro forecast. When
7 a new year of data becomes available it becomes the first year data and the prior first year
8 data becomes the second year data and so forth until the prior 29th year data becomes the
9 30th year data and the prior 30th year data is excluded. This provides customers and the
10 Company with a balanced recovery of generation benefits over the 30-year period.

11
12 **Q. HAS THE COMPANY'S BEAR RIVER NORMALIZATION DEVIATED FROM**
13 **THE 30-YEAR NORMALIZATION METHOD IN RECENT YEARS?**

14 A. Yes. The Company's calculation of normalized hydro generation for Bear River began to
15 exclude flood control years from the 30 year historical record starting in 2008. In
16 response to WIEC Data Request 8.24 in Docket No. 20000-333-ER-08, the Company
17 explained how they adjusted Bear River generation and explained their reasons for the
18 adjustments:

19 The inflow forecast for Bear River was recently reduced. Years in which surplus
20 water was released from Bear Lake ("flood control years") were removed from
21 the historical data set from which the Bear River generation forecast is derived.
22 Flood control years provide additional water for Bear River generation. However,
23 the region is currently impacted by long-term drought conditions and based on the
24 low water level in Bear Lake the probability of a flood control year is minimal for
25 the next three years.
26

1 **Q. DO THE DROUGHT CONDITIONS PROVIDE A LEGITIMATE BASIS FOR**
2 **EXCLUDING FLOOD CONTROL YEARS FROM THE CALCULATION OF**
3 **NORMALIZED GENERATION?**

4 A. No. Arbitrarily removing flood control water year data from the historical record because
5 drought conditions are expected to persist is not consistent with the 30-Year
6 normalization methodology employed by the Company for other small projects or the
7 methodology employed for other larger projects. The Bear River methodology is clearly
8 a case of cherry picking, which produces higher NPC because it excludes the nine highest
9 generation years from the thirty-year normalization period. Those nine years have a
10 median annual generation of 563,114 MWh. In contrast, the years included in the
11 Company's filing have a median generation forecast of 205,576 MWh. Put another way,
12 the Company's Bear River generation normalization transfers customer's benefits of
13 higher hydro generation to shareholders.

14
15 **Q. IS THE BEAR RIVER ADJUSTMENT SYMMETRICAL FROM THE**
16 **PERSPECTIVE OF PREVIOUS HYDRO ADJUSTMENTS OR FILINGS?**

17 A. No. To the best of my knowledge, the Company has never volunteered adjustments to
18 increase hydro generation and decrease NPC based on an expectation of a good water
19 year. For the reasons explained above, I recommend that the Company's Bear River
20 normalization should be revised to use the same 30-year normalization methodology used
21 for other small hydro facilities. My recommendation reduces NPC by approximately
22 \$0.13 million on an Idaho basis.

1 **Adjustment 13. BLACK HILLS SHAPING**

2 **Q. PLEASE EXPLAIN THE COMPANY'S MODELING FOR THE BLACKHILLS**
3 **WHOLESALE SALES CONTRACT.**

4 A. The contract is classified as a call option contract in GRID and the contract terms for
5 energy such as hourly, daily weekly, monthly and annual take and delivery points are
6 inputs to GRID. Based on this information and the Company's forward price curve
7 GRID dispatches the contract during the highest cost hours based on the assumption that
8 is what the purchasing entity would do.

9
10 **Q. DO YOU AGREE WITH THIS ASSUMPTION?**

11 A. No. While the assumption may be reasonable for some contracts it really depends on the
12 requirements and assumptions of the purchasing entity. In the case of Black Hills, the
13 actual delivery shape of the sale is much flatter than it is modeled in GRID. As shown
14 below in Graph 1, Black Hills Dispatch, the difference between actual on and off-peak
15 deliveries is smaller (flatter) than the difference between the Company's modeled on and
16 off-peak deliveries.

17

18

19

20

21

22

23

24

25

26

27

28

29

30

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24

Q. ARE YOU SURPRISED BY THE SHAPING DIFFERENCE?

A. No. The difference is not surprising because the Company simply does not know what Black Hills system requirements and assumptions are. In this case, the assumption that Black Hills would do exactly what the Company thinks they would do is incorrect and results in a higher contract cost in GRID than occurs on an actual basis. To correct this problem the energy shape should be modeled using the actual delivery shape.

Q. DOES THE COMPANY USE ANY ACTUAL INFORMATION TO MODEL OTHER ASPECTS OF THE BLACKHILLS CONTRACT?

A. Yes. The delivery points for the contract are modeled based on actual information. The purpose of using actual delivery points is to capture the expected cost of the sale because the energy can be delivered on both the east and west side of the Company's system. This fact also suggests that the energy shape should use actual information.

Q. DOES THE COMPANY USE ACTUAL INFORMATION TO MODEL OTHER CONTRACTS?

A. Yes. Actual information is also used to model other contracts. For example, energy for the Gem State contract is modeled for the months of May, June, July and August based on historical information despite the fact that the contract states that deliveries are expected to occur during June, July and August. The Company also uses actual data for various inputs of other contracts and GRID inputs such GP Camas, APS, Biomass and forced and planned outages etc.

1 **Q. WHAT IS YOUR RECOMMENDATION?**

2 A. The Black Hills wholesale sales contract should be modeled based on a four a four-year
3 average of historical dispatch information. This adjustment reduces NPC by \$0.08
4 million on an Idaho basis.

5

6 **Adjustment 14. MONA MARKET**

7 **Q. PLEASE EXPLAIN HOW PACIFICORP SIZED THE MONA WHOLESALE**
8 **MARKET HUB?**

9 A. The Company modeled the market capacity as no graveyard market (the five hours ended
10 1:00 AM through 6:00AM Pacific time) and 75 MW in all other hours.

11

12 **Q. DOES THE MONA WHOLESALE SALES MARKET CONSIST SOLELY OF**
13 **SALES WITH A MONA POINT OF DELIVERY (POD) DESIGNATION?**

14 A. No. According to Confidential Attachment Monsanto 2.15, the Mona market consists of
15 Mona, Gonder, Red Butte, Sierra Pacific system (SPPC) and Nevada Utah Border (NUB)
16 PODs.

17

18 **Q. GIVEN THIS INFORMATION, HAS PACIFICORP ADEQUATELY SIZED THE**
19 **MONA MARKET?**

20 A. No. As shown below in Table 3, the Company's Mona market capacity is considerably
21 understated based on a comparison wholesale sales volume for the 48-month period
22 ended December 31, 2009.

Table 3 Mona Market Size Comparison Average Megawatts				
	PacifiCorp		Actual 48-Month Avg.	
	All Other Hours	Graveyard	All Other Hours	Graveyard
January	/1	0	/1	27
February	/1	0	/1	24
March	/1	0	/1	20
April	/1	0	/1	15
May	75	0	75	17
June	75	0	183	21
July	75	0	229	26
August	75	0	296	44
September	75	0	240	36
October	75	0	151	25
November	75	0	132	24
December	75	0	167	17
/1 Not applicable because filing uses actual 2010 data				

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15

Q. WHY DID YOU USE A 48-MONTH AVERAGE FOR THE COMPARISON SHOWN IN TABLE 3?

A. I used a 48-month average to be consistent with the Company's normalization of thermal generation, STF transmission capacity and graveyard market caps, which all use a 48-month normalization period.

Q. WHAT IS YOUR RECOMMENDATION FOR CURRING THE CONSIDERABLE UNDERSTATEMENT OF THE MONA MARKET?

A. The Mona market capacity needs to be sized appropriately to provide a proper match of costs and benefits. I recommend that the Mona market capacity be corrected by using the 48-month average capacities shown above in Table 3. This adjustment reduces NPC by approximately \$0.03 million on an Idaho basis.

1 **Adjustment 15. NAUGHTON 3 OUTAGE**

2 **Q. PLEASE EXPLAIN THE CAUSE OF THE NAUGHTON 3 OUTAGE WHICH**
3 **STARTED MAY 8, 2009 AND ENDED MAY 26, 2009.**

4 A. The Company's contractor Siemens failed to complete the Naughton 3 overhaul on
5 schedule per contract terms due to poor performance. The major reasons for the failure to
6 meet contract terms include failure to achieve good alignment of the HP and LP turbine,
7 lack of experienced and skilled journeyman and craft supervision and poor quality control
8 resulting in many items being reworked.

9
10 **Q. DID THE COMPANY RECIEVE COMPENSATION FROM SIEMENS FOR**
11 **FAILURE TO MEET CONTRACT TERMS?**

12 A. Yes. Pursuant to the terms of the contract the Company received a \$500,000 liquidated
13 damages payment in June 2009 that was booked to FERC account 555 purchase power
14 expense.

15
16 **Q. DID IDAHO RETAIL CUSTOMERS RECEIVE AN ALLOCATED SHARE OF**
17 **THE \$500,000 PAYMENT?**

18 A. No. The ECAM did not become effective until July 1, 2009.

19
20 **Q. DO YOU AGREE WITH THE COMPANY'S INCLUSION OF THE OUTAGE**
21 **EVENT IN NPC?**

22 A. No. The outage was caused by poor performance of the Company's contractor (Siemens)
23 and is therefore an imprudent outage that should not be included in the calculation of
24 NPC. Furthermore, the Company has already been compensated for the outage pursuant

1 to the terms of their contract through the \$500,000 liquidated damage payment it
2 received. Inclusion, of the outage in NPC would result in the Company collecting outage
3 costs twice, once from customers and once from Siemens. For these reasons, I
4 recommend that the outage be removed from the calculation of NPC. This adjustment
5 reduces NPC by approximately \$0.03 million on an Idaho basis.

6
7 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

8 **A. Yes.**

Randall C. Budge, ISB No. 1949
RACINE, OLSON, NYE, BUDGE &
BAILEY, CHARTERED
P.O. Box 1391; 201 E. Center
Pocatello, Idaho 83204-1391
Telephone: (208) 232-6101
Fax: (208) 232-6109
rcb@racinelaw.net

RECEIVED
2010 NOV 22 AM 9: 34
IDAHO PUBLIC
UTILITIES COMMISSION

Attorneys for Intervenor Monsanto Company

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF)
ROCKY MOUNTAIN POWER FOR APPROVAL) **Case No. PAC-E-10-07**
OF CHANGES TO ITS ELECTRIC SERVICE)
SCHEDULES AND A PRICE INCREASE OF)
\$27.7 MILLION, OR APPROXIMATELY) **PROOF OF SERVICE**
13.7 PERCENT)
_____)

I HEREBY CERTIFY that on this 19th day of November, 2010, I served a true, correct and complete copy of the *Errata Sheet and Corrected Direct Testimony of Mark T. Widmer on Behalf of Monsanto*, to each of the following in the manner indicated:

Jean D. Jewell, Secretary (original and 9) Overnight Mail
Idaho Public Utilities Commission
472 West Washington Street
Boise, Idaho 83702-5918

Ted Weston Overnight Mail
Rocky Mountain Power
201 South Main, Ste 2300
Salt Lake City, Utah 84111

Paul J. Hickey Overnight Mail
Hickey & Evans, LLP
1800 Carey Ave., Ste 700
Cheyenne, WY 82003

Mark C. Moench
Daniel Solander
Rocky Mountain Power
201 S. Main Street, Ste 2300
Salt Lake City, Utah 84111

Overnight Mail

Katie Iverson
Brubaker & Associates
17244 W. Cordova Court
Surprise, Arizona 85387

U.S. Mail

James R. Smith
Monsanto Company
P.O. Box 816
Soda Springs, Idaho 83276

U.S. Mail

Eric L. Olsen
Racine, Olson, Nye, Budge & Bailey
P.O. Box 1391
Pocatello, Idaho 83204-1391

Hand Delivered

Anthony Yankel
29814 Lake Road
Bay Village, Ohio 44140

U.S. Mail

Tim Buller
Jason Harris
Agrium, Inc.
3010 Conda Road
Soda Springs, Idaho 83276

U.S. Mail

Benjamin J. Otto
Idaho Conservation League
P.O. Box 844
Boise, Idaho 83702

U.S. Mail

Dr. Don Reading
6070 Hill Road
Boise, Idaho 83703

U.S. Mail

Melinda J. Davison
Davison Van Cleve, PC
333 SW Taylor, Ste 400
Portland, Oregon 97204

Overnight Mail

Ronald L. Williams
Williams Bradbury, PC
1015 W. Hays Street
Boise, Idaho 83702

Overnight Mail

Brad M. Purdy
Attorney at Law
2019 N. 17th Street
Boise, Idaho 83702

Overnight Mail

RACINE, OLSON, NYE, BUDGE &
BAILEY, CHARTERED

By Bonnie K. Hill, Paralegal
for RANDALL C. BUDGE