EXHIBIT A

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

201 South Main, Suite 2300
Salt Lake City, Utah 84111

March 8, 2012

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84111

Attn: Gary Widerburg
Commission Secretary

Re: **Docket No. 03-035-14 – Quarterly Compliance Filing – 2012.Q1 Avoided Cost Input Changes**

Commission Orders dated October 31, 2005 and February 2, 2006 in Case No. 03-035-14 state that the Company is required to keep a record of any changes, including data inputs, made to the Proxy and GRID models used in calculating avoided costs. The Orders further require the Company to notify the Commission and Division of Public Utilities of updates made to the models used in the approved Proxy and Partial Displacement Differential Revenue Requirement (PDDRR) avoided cost methodologies.

This filing reports changes since the Company's last compliance filing dated November 30, 2011, Docket No. 03-035-14.

PacifiCorp (dba Rocky Mountain Power) hereby respectfully submits an original and five copies of this compliance filing to address this requirement. An electronic copy of this filing will be provided to psc@utah.gov. Additional detail is provided below:

1. GRID Model Data Updates

A number of data and modeling assumption updates have occurred in the GRID model since the last filing. **Appendix A** provides a summary of those updates.

2. Proxy / Partial Displacement Differential Revenue Requirement Avoided Cost Methodology

The Proxy used in the Partial Displacement Differential Revenue Requirement (PDDRR) avoided cost methodology is consistent with the Company's 2011 Integrated Resource Plan (2011 IRP) which was filed with the Commission on March 31, 2011. During the period 2013 through 2015 the proxy will be third quarter high load hour only front office trades and starting June 2016 the proxy is a 597 MW combined cycle combustion turbine (CCCT). Both proxy resources are listed in Table 8.16 of the 2011 IRP.

3. Impact to Avoided Cost Prices ($/MWh)

Provided as **Appendix B** is a $/MWh impact study of the above mentioned updates, together with a comparison to the last filing. The updates reflect a decrease of $3.37 /MWh on a 20-year nominal levelized basis. Avoided costs presented in **Appendix B** were calculated assuming a 100 MW 85% capacity factor QF resource.

4. Major Changes from the Prior Study

Provided as **Appendix C** is a $/MWh step impact study of the major changes from the prior study. The major changes since the prior study were the update to the most recent Official Forward Price Curve and the incorporation of other modeling updates. Also provided in **Appendix C** is the incremental impact of each change from the prior step.

5. Proxy Wind Resource

The selection of Dunlap I Wind as the proxy wind resource is unchanged from the Company's 2009.Q4 Compliance Filing dated March 9, 2010.

It is respectfully requested that all formal correspondence and requests regarding this compliance filing be addressed to:

By E-Mail (preferred) : datarequest@pacificorp.com

By Regular Mail : Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, OR 97232

Informal inquiries may be made to Laren Hale at (503) 813-6054 or Bradley Mullins at (503) 813-6013.

Very truly yours,

Jeffrey K. Larsen
Vice President, Regulation & Government Affairs

cc: Service List (Docket No. 03-035-14)

CERTIFICATE OF SERVICE

I hereby certify that a true and correct copy of the foregoing **Quarterly Compliance Filing – Avoided Cost Input Changes in Docket No. 03-035-14** was served upon the following by email on March 8, 2012:

Michael Ginsberg
Patricia Schmid
Assistant Attorney General
500 Heber M. Wells Building
160 East 300 South
Salt Lake City, Utah 84111
mginsberg@utah.gov
Pschmid@utah.gov

Paul Proctor
Assistant Attorney General
500 Heber M. Wells Building
160 East 300 South
Salt Lake City, UT 84111
pproctor@utah.gov

Roger Swenson
E-Quant Consulting, Inc.
1592 East 3350 South
Salt Lake City, UT 84106
Roger.swenson@prodigy.net

Stephen F. Mecham
Callister Nebeker & McCullough
10 East South Temple, Suite 900
Salt Lake City, UT 84133
sfmecham@cnmlaw.com

Gregory L. Probst
c/o Energy Strategies
39 Market Street, Suite 200
Salt Lake City, UT 84101
glprobst@earthlink.net

Gary A. Dodge
Hatch James & Dodge
10 West Broadway, #400
Salt Lake City, UT 84101
gdodge@hjdlaw.com

Aeri E. York
ExxonMobil Power and Gas Services, Inc.
800 Bell Street
Houston, TX 77002-2180
aeri.e.york@exxonmobil.com

James W. Holtkamp
Holland & Hart, LLP
60 East South Temple, Suite 2000
Salt Lake City, UT 84111
jholtkamp@hollandhart.com

Thor Nelson
Holland & Hart LLP
8390 East Crescent Parkway, Suite 400
Greenwood Village, CO 80111-2811
tnelson@hollandhart.com

Richard Collins & Tracy Livingston Mikell
Wasatch Wind LLC
357 West 910 South
Heber City, UT 84032
rcollins@westminstercollege.edu

Sarah Wright
Utah Clean Energy
917 2nd Avenue
Salt Lake City, UT 84103
sarah@utahcleanenergy.org

Lt. Col. Karen White
FEA
139 Barnes Drive, Suite 1
Tyndall AFB, FL 32403-5319
Karen.white@tyndall.af.mil

Mike Lund
OO-ALC/JAN
6026 Cedar Lanes, Bldg. 1278
Hill AFB, UT 84056
michael.lund@hill.af.mil

Kelly Francone
Neal Townsend
Energy Strategies LLC
215 South State, Suite 200
Salt Lake City, UT 84111
kfrancone@energystrat.com
ntownsend@energystrat.com

Lee Brown
US Magnesium LLC
238 North 2200 West
Salt Lake City, UT 84116
lbrown@Magnesiumcorp.com

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Carrie Meyer
Coordinator, Regulatory Operations

Appendix A

PacifiCorp
Avoided Cost (GRID and Differential Revenue Requirement)
Model Updates through February 2012
Case No. 03-035-14

GRID Scenario Study Period

January 1, 2013 through December 31, 2032 (20-year study)
Avoided Cost prices starting in January 2013

Official Forward Price Curve (Gas and Market Prices)

Updated to PacifiCorp's December 2011 official forward price curve (1112 OFPC)

Short-Term Firm (STF) Transactions

STF transactions have been updated to include executed STF contracts as of February 2012

Market Capacity

48 Months ended June 2011
Market cap HLH & LLH sales limited to 48 month average of all STF sales less monthly executed STF contracts as of February 2012

Inflation Rates

The Company updated inflation rates consistent with the Company's most recent inflation rate study dated December 2011

Discount Rate

7.17% which is the discount rate used in the 2011 IRP. This discount rate is consistent with the Commission's order in Docket 11-035-T06.

Load Forecast (Retail)

20-year load forecast dated November 2011

Fuel Prices (Coal)

Average coal cost study
2013 through 2021 – 10 Year forecast dated October 2011
Thereafter escalated at 2.5%
Incremental coal cost study dated October 2011

Potential Environmental Costs

Costs are consistent with the Company's forecast dated December 2011
Costs are excluded from fuel costing and are excluded from avoided costs
Costs included in incremental fuel costs for plant commitment and dispatch decisions starting in 2021
Environmental costs are for carbon dioxide

Proxy Resource (Next Deferrable Resource)

2013 through 2015 - Mona, Utah, West Main, Mid-Columbia and COB Third Quarter (Q3) High Load Hour (HLH) Front Office Trade (FOT) – 2011 IRP Table 8.16
2016 and thereafter – 597 MW Combined Cycle Combustion Turbine (CCCT) Dry "F" 2x1 - East Side Resource (4500') – 2011 IRP Table 6.1 & 6.3
Commencing operation June 1, 2016

IRP Resources

IRP Resources transmission, thermal, DSM, FOT, Growth Station and wind resources
2011 IRP Dated March 31, 2011
Preferred Portfolio Table 8.16

IRP Partial Displacements (this filing)

Thermal and Market Purchase Resources

Base Case - thermal partial displacement was 197.4 MW. Included are QFs that are actively negotiating for new power purchase agreements as shown below.

Queue	Thermal Resource	Capacity MW	Energy – Capacity Factor
1	Roseburg Dillard Biomass (Signed)	20.0	90.0%
2	Roseburg Weed Biomass (Signed)	10.0	85.0%
3	AG Hydro (Signed)	10.0	29.7%
4	Dorena Hydro (Signed)	6.1	28.2%
5	TMF Biofuels (Signed)	4.8	88.5%
6	Columbia Biogas (Signed)	3.0	45.7%
7	QF - 10 - UT - Biogas	3.0	95.0%
8	QF - 18 - UT - Biomass	10.5	94.0%
9	QF - 21 - UT - Gas	36.0	95.0%
10	QF - 23 - UT - Gas	44.0	85.0%
11	QF - 24 - UT - Gas	50.0	85.0%
Displacement in Base Case MW		**197.4 MW**	

Market front office trades (FOT) are displaced based upon the year the FOT is availability and from highest to lowest price. FOT available in order of highest to lowest price are Mona (Available 2013), Utah, West Main, Mid Columbia, and California Oregon Border (COB). FOT are listed in Table 8.16 of the 2011 IRP. The partial displacement is shown below.

Displacement in Base Case				
Year	Displaced Resource	2011 IRP	Displacement	Remaining MW
2013	FOT – Mona – Utah	150 204	150.0 47.4	0.0 156.6
2014	FOT – Mona	300	197.4	102.6
2015	FOT – Mona	300	197.4	102.6
2016	597 MW CCCT Dry "F" 2x1 - East Side Resource (4500')	597	197.4	399.6

Avoided Cost Case – a 100 MW 85% capacity factor (CF) avoided cost resource is added to the thermal resource queue.

Queue	Thermal Resource	Capacity MW	Energy – Capacity Factor
1	Roseburg Dillard Biomass (Signed)	20.0	90.0%
2	Roseburg Weed Biomass (Signed)	10.0	85.0%
3	AG Hydro (Signed)	10.0	29.7%
4	Dorena Hydro (Signed)	6.1	28.2%
5	TMF Biofuels (Signed)	4.8	88.5%
6	Columbia Biogas (Signed)	3.0	45.7%
7	QF - 10 - UT - Biogas	3.0	95.0%
8	QF - 18 - UT - Biomass	10.5	94.0%
9	QF - 21 - UT - Gas	36.0	95.0%
10	QF - 23 - UT - Gas	44.0	85.0%
11	QF - 24 - UT - Gas	50.0	85.0%
12	Avoided Cost Resource	100.0	85.0%
Displacement in Base Case MW		**297.4 MW**	

The Table below shows the FOT that are displaced for the Avoided Cost Case which includes the 100 MW 85% capacity factor avoided cost resource.

Displacement in Avoided Cost Case				
Year	Displaced Resource	2011 IRP	Displacement	Remaining MW
2013	FOT – Mona – Utah	150 204	150.0 147.4	0.0 56.6
2014	FOT – Mona	300	297.4	2.6
2015	FOT – Mona	300	297.4	2.6
2016	597 MW CCCT Dry "F" 2x1 - East Side Resource (4500')	597	297.4	299.6

Wind Resources

A total of 2,100 MW of wind is included in the 2011 IRP of which 489.5 MW is partially displaced by potential and signed QF Wind Resources. All IRP wind is located in Wyoming with the first proposed wind projects available in 2018. The Table below shows the potential wind resources that partially displace the 2,100 MW of wind listed in the IRP.

Potential and Signed QF Wind Resource		
Year	Displaced Resource	MW
2013	Blue Mtn Wind I (Signed)	80.0
2012	North Point Wind (Signed)	80.0
2012	Five Pine Wind (Signed)	40.0
2013	High Plateau Wind QF (Signed)	10.0
2013	Lower Ridge Wind QF (Signed)	10.0
2013	Mule Hollow Wind QF (Signed)	10.0
2013	Pine City Wind QF (Signed)	10.0
2013	QF - 14 - WY - Wind	76.5
2014	QF - 15 - WY - Wind	76.5
2014	QF - 19 - WY - Wind	76.5
2016	QF - 06 - ID - Wind	20.0
Wind Resource Partial Displacement of IRP Wind		489.5

The 489.5 MW of potential QF wind resources will displace 300 MW of IRP wind scheduled for 2018 will displace 189.5 MW of wind scheduled for 2019.

IRP Partial Displacements (last filing)

Thermal and Market Purchase Resources

Base Case - thermal partial displacement was 123.1 MW. Included are QFs that are actively negotiating for new power purchase agreements as shown below.

Queue	Thermal Resource	Capacity MW	Energy – Capacity Factor
1	QF - 02 - OR - Biomass	38.5	85.0%
2	QF - 05 - OR - Biomass	10.0	85.0%
3	Roseburg Dillard Biomass (Signed)	20.0	90.0%
4	AG Hydro (Signed - QF Oregon)	10.0	29.7%
5	Dorena Hydro (Signed - QF Oregon)	6.1	28.2%
6	QF - 10 - UT - Biogas	3.0	95.0%
7	QF - 16 - UT - Geothermal	25.0	69.3%
8	QF - 18 - UT - Biomass	10.5	94.0%
Displacement in Base Case MW		**123.1 MW**	

Market front office trades (FOT) are displaced based upon the year the FOT is availability and from highest to lowest price. FOT available in order of highest to lowest price are Mona (Available 2013), Utah, West Main, Mid Columbia, and California Oregon Border (COB). FOT are listed in Table 8.16 of the 2011 IRP. The partial displacement is shown below.

Displacement in Base Case				
Year	Displaced Resource	2011 IRP	Displacement	Remaining MW
2012	FOT – Utah – West Main	200 50	123.1 0.0	76.9 50.0
2013	FOT – Mona – Utah	150 204	123.1 0.0	26.9 204.0
2014	FOT – Mona	300	123.1	176.9
2015	FOT – Mona	300	123.1	176.9
2016	597 MW CCCT Dry "F" 2x1 - East Side Resource (4500')	597	123.1	473.9

Avoided Cost Case – a 100 MW 85% capacity factor (CF) avoided cost resource is added to the thermal resource queue.

Queue	Thermal Resource	Capacity MW	Energy – Capacity Factor
1	QF - 02 - OR - Biomass	38.5	85.0%
2	QF - 05 - OR - Biomass	10.0	85.0%
3	Roseburg Dillard Biomass (Signed)	20.0	90.0%
4	AG Hydro (Signed - QF Oregon)	10.0	29.7%
5	Dorena Hydro (Signed - QF Oregon)	6.1	28.2%
6	QF - 10 - UT - Biogas	3.0	95.0%
7	QF - 16 - UT - Geothermal	25.0	69.3%
8	QF - 18 - UT - Biomass	10.5	94.0%
9	Avoided Cost Resource	100.0	85.0%
Displacement in Base Case MW		**223.1 MW**	

The Table below shows the FOT that are displaced for the Avoided Cost Case which includes the 100 MW 85% capacity factor avoided cost resource.

Displacement in Avoided Cost Case				
Year	Displaced Resource	2011 IRP	Displacement	Remaining MW
2012	FOT – Utah – West Main	200 50	200.0 23.1	0.0 26.9
2013	FOT – Mona – Utah	150 204	150.0 73.1	0.0 130.9
2014	FOT – Mona	300	223.1	76.9
2015	FOT – Mona	300	223.1	76.9
2016	597 MW CCCT Dry "F" 2x1 - East Side Resource (4500')	597	223.1	373.9

Wind Resources

A total of 2,100 MW of wind is included in the 2011 IRP of which 684.0 MW is partially displaced by potential QF Wind Resources. All IRP wind is located in Wyoming with the first proposed wind projects available in 2018. The Table below shows the potential wind resources that partially displace the 2,100 MW of wind listed in the IRP.

Potential and Signed QF Wind Resource		
Year	**Displaced Resource**	**MW**
2012	QF - 01 - ID - Wind	133.0
2013	QF - 03 - ID - Wind	78.0
2013	QF - 06 - ID - Wind	20.0
2013	Blue Mtn Wind I (Signed – QF Utah)	80.0
2012	QF - 08 - OR - Wind	40.0
2013	QF - 09 - ID - Wind	80.0
2012	QF - 12 - ID - Wind	20.0
2013	QF - 14 - WY - Wind	76.5
2014	QF - 15 - WY - Wind	76.5
2013	QF - 17 - UT - Wind	80.0
Wind Resource Partial Displacement of IRP Wind		684.0

The 684.0 MW of potential QF wind resources will displace all IRP wind scheduled for 2018 and 2019, 300 MW each year, and will displace 84.0 MW of wind scheduled for 2020.

Regulating Margin

Regulating margin was updated to recognize that the study start date has shift from the 2012 to the 2013

Size of the Avoided Cost Resource

The avoided cost resource is assumed to be a 100 MW 85% CF thermal resource. The size of the avoided cost resource has not been changed.

Topology

There were no changes to the GRID model topology.

Transmission (Firm Transmission Rights)

There were no changes to firm transmission rights.

Transmission (Non-Firm and Short Term Firm)

Non-firm transmission - 48 months ended June 2011
Short term firm transmission – 48 months ended June 2011
STF and non-firm combined and modeled as a single transmission link
Modeled without incremental wheeling costs
This assumption has not changed from the last filing

Thermal Resources

Thermal resources operating characteristics were updated to reflect expected operations. Forced Outage, Planned Outage and Heat rate levels reflect 48 months ended June 2011.

Long-Term Contracts

Long-term contracts which have prices that are indexed to market were updated to be consistent with the 2011 December Official Forward Price Curve (1112 OFPC).

Modeling updates include: Biomass One and SCL State Line. Seven wind QFs were added: Blue Mountain, Five Pine, High Plateau, Lower Ridge, Mule Hollow, North Point and Pine City. Modeling was added to more accurately track electric swaps transactions.

Hydro Resources

10 year forecast dated September 9, 2011
Hydro forecast extended past 2022 at 2022 hydro level

Appendix B

Avoided Cost Prices $/MWh
Utah Compliance Filing 2012.Q1 - 100 MW and 85% Capacity Factor

Year	Avoided Cost at 85.0% CF (2)	2011.Q4 Compliance Filing (2)	Difference
2013	$31.31	$35.18	($3.87)
2014	$32.85	$37.26	($4.41)
2015	$34.05	$38.24	($4.19)
2016	$41.97	$45.89	($3.92)
2017	$51.75	$56.50	($4.75)
2018	$56.37	$59.47	($3.10)
2019	$59.75	$62.11	($2.36)
2020	$58.50	$60.65	($2.15)
2021	$62.69	$67.30	($4.61)
2022	$66.82	$67.91	($1.09)
2023	$68.73	$69.14	($0.41)
2024	$68.45	$70.78	($2.33)
2025	$70.41	$72.28	($1.87)
2026	$73.38	$76.31	($2.93)
2027	$75.48	$79.17	($3.69)
2028	$77.10	$81.06	($3.96)
2029	$78.98	$83.29	($4.31)
2030	$80.27	$84.62	($4.35)
2031	$81.61	$85.97	($4.36)
2032	$83.71	$87.32	($3.61)

20-Year Levelized Prices (Nominal) @ 7.17% Discount Rate (1)

$/MWh	$56.37 (3)	$59.74 (4)	($3.37)

Footnotes:

(1) 2011 IRP Discount Rate

(2) Total Avoided Costs with Capacity included at an 85.0% capacity factor

(3) 20-Year NPC is 2013 - 2032
Avoided Costs calculated monthly are $56.37/MWH

(4) 2032 extrapolated

Appendix B

Table 1

Avoided Cost Prices

Utah Compliance Filing 2012.Q1 - 100 MW and 85% Capacity Factor

Partial Displacement of East Side 597 MW CCCT (Dry "F" 2x1)

Year	Capacity Price $/kW-yr		Energy Only Price $/MWh [(2)]	Total Price @ 85.0% Capacity Factor $/MWh
2013	$0.00		$31.31	$31.31
2014	$0.00		$32.85	$32.85
2015	$0.00		$34.05	$34.05
2016	$84.61	(4)	$30.64	$41.97
2017	$147.80		$31.90	$51.75
2018	$150.60		$36.14	$56.37
2019	$153.32		$39.16	$59.75
2020	$155.93		$37.61	$58.50
2021	$158.73		$41.37	$62.69
2022	$161.60		$45.12	$66.82
2023	$164.51		$46.63	$68.73
2024	$167.47		$46.02	$68.45
2025	$170.50		$47.51	$70.41
2026	$173.58		$50.07	$73.38
2027	$176.86		$51.73	$75.48
2028	$180.24		$52.96	$77.10
2029	$183.65		$54.32	$78.98
2030	$187.13		$55.14	$80.27
2031	$190.87		$55.98	$81.61
2032	$194.49		$57.66	$83.71

20-Year Levelized Prices (Nominal) @ 7.17% Discount Rate (1) (3)

$/kW	$118.16		
$/MWh		$40.51	$56.37 (5)

Footnotes:

(1) Discount Rate - Company Official Discount Rate

(2) 'Energy Only' is the GRID calculated costs and includes some capacity costs.

(3) 20 Year NPC is 2013 - 2032

(4) Capacity payment for 2016 is 7/12 of annual. CCCT start 6/1/2016.

(5) Avoided Costs calculated annually starting January 2013
Avoided Costs calculated monthly are $56.37/MWH

Appendix B

Table 2

Avoided Energy Costs - Scheduled Hours ($/MWh)
Utah Compliance Filing 2012.Q1 - 100 MW and 85% Capacity Factor
Partial Displacement of East Side 597 MW CCCT (Dry "F" 2x1)

Year		Winter Season					Summer Season				Winter Season			IRP Resource
	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Energy Cost
Energy Only														
2013	$31.31	$29.91	$30.57	$28.99	$26.29	$24.94	$23.93	$40.32	$42.16	$40.15	$29.94	$28.61	$29.63	$0.00
2014	$32.85	$31.92	$33.27	$32.06	$28.16	$26.78	$23.87	$43.45	$43.83	$42.72	$29.56	$27.61	$30.67	$0.00
2015	$34.05	$31.08	$30.44	$31.71	$29.18	$26.92	$26.99	$46.95	$46.64	$46.48	$32.66	$27.99	$31.06	$0.00
2016	$30.64	$30.58	$31.84	$33.15	$28.46	$30.31	$26.80	$30.35	$30.48	$28.95	$30.29	$32.89	$33.50	$32.92
2017	$31.90	$34.52	$31.92	$32.84	$31.51	$29.17	$28.32	$32.12	$32.34	$31.12	$32.78	$32.71	$33.33	$34.90
2018	$36.14	$40.03	$36.39	$36.78	$36.11	$35.07	$33.49	$36.06	$36.14	$34.35	$35.73	$35.73	$37.70	$38.21
2019	$39.16	$40.24	$38.64	$39.63	$37.67	$39.37	$38.64	$40.23	$40.37	$37.69	$37.90	$38.99	$40.38	$41.52
2020	$37.61	$38.41	$39.14	$37.51	$38.81	$37.70	$36.61	$38.24	$38.41	$32.64	$37.71	$36.82	$39.29	$40.47
2021	$41.37	$40.72	$41.46	$40.65	$43.34	$40.86	$40.00	$40.87	$40.79	$40.72	$41.51	$42.88	$42.71	$42.79
2022	$45.12	$44.11	$44.19	$45.13	$47.99	$44.90	$42.69	$44.54	$44.82	$44.56	$45.00	$45.23	$48.16	$47.02
2023	$46.63	$50.24	$46.67	$47.69	$50.89	$46.28	$45.38	$46.75	$46.91	$44.11	$44.88	$44.66	$45.09	$48.50
2024	$46.02	$45.85	$47.72	$46.20	$49.43	$45.95	$44.35	$45.19	$45.48	$45.03	$45.85	$45.72	$45.64	$47.66
2025	$47.51	$48.17	$48.04	$47.46	$51.59	$46.99	$45.18	$46.67	$46.76	$46.87	$47.36	$47.53	$47.63	$49.00
2026	$50.07	$51.48	$49.26	$51.45	$55.10	$49.76	$48.27	$49.55	$49.17	$48.55	$49.44	$49.17	$49.58	$51.82
2027	$51.73	$52.23	$51.43	$51.37	$57.42	$51.63	$50.13	$51.61	$51.74	$49.86	$51.48	$50.74	$51.08	$53.65
2028	$52.96	$51.81	$54.00	$52.54	$59.26	$53.25	$51.38	$51.81	$52.80	$51.54	$53.06	$52.14	$52.06	$54.78
2029	$54.32	$54.45	$53.52	$54.21	$60.50	$53.74	$52.67	$53.53	$53.56	$52.69	$54.29	$54.37	$54.30	$55.62
2030	$55.14	$56.83	$56.44	$54.00	$61.19	$54.18	$51.77	$54.02	$54.28	$53.72	$54.48	$54.83	$56.05	$55.91
2031	$55.98	$57.24	$57.48	$54.08	$60.23	$53.77	$52.37	$52.80	$52.95	$56.99	$59.44	$57.57	$57.02	$57.18
2032	$57.66	$58.24	$58.81	$55.12	$62.71	$54.72	$54.74	$53.86	$54.08	$57.71	$61.24	$61.01	$59.93	$58.30

IRP Resource Energy Costs are provided for comparison purposes only.

Appendix B

Table 3

Avoided Energy Costs - Unscheduled or Non-dispatch hours($/MWh)
Utah Compliance Filing 2012.Q1 - 100 MW and 85% Capacity Factor
Partial Displacement of East Side 597 MW CCCT (Dry "F" 2x1)

Year		Winter Season					Summer Season				Winter Season			IRP Resource
	Annual	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Energy Cost
Energy Only														
2013	$31.31	$29.91	$30.57	$28.99	$26.29	$24.94	$23.93	$40.32	$42.16	$40.15	$29.94	$28.61	$29.63	$0.00
2014	$32.85	$31.92	$33.27	$32.06	$28.16	$26.78	$23.87	$43.45	$43.83	$42.72	$29.56	$27.61	$30.67	$0.00
2015	$34.05	$31.08	$30.44	$31.71	$29.18	$26.92	$26.99	$46.95	$46.64	$46.48	$32.66	$27.99	$31.06	$0.00
2016	$30.57	$30.58	$31.84	***$32.92***	$28.46	$30.31	$26.80	$30.35	$30.48	$28.95	$30.29	$32.89	***$32.92***	$32.92
2017	$31.90	$34.52	$31.92	$32.84	$31.51	$29.17	$28.32	$32.12	$32.34	$31.12	$32.78	$32.71	$33.33	$34.90
2018	$36.14	$40.03	$36.39	$36.78	$36.11	$35.07	$33.49	$36.06	$36.14	$34.35	$35.73	$35.73	$37.70	$38.21
2019	$39.16	$40.24	$38.64	$39.63	$37.67	$39.37	$38.64	$40.23	$40.37	$37.69	$37.90	$38.99	$40.38	$41.52
2020	$37.61	$38.41	$39.14	$37.51	$38.81	$37.70	$36.61	$38.24	$38.41	$32.64	$37.71	$36.82	$39.29	$40.47
2021	$41.32	$40.72	$41.46	$40.65	***$42.79***	$40.86	$40.00	$40.87	$40.79	$40.72	$41.51	***$42.79***	$42.71	$42.79
2022	$44.93	$44.11	$44.19	$45.13	***$47.02***	$44.90	$42.69	$44.54	$44.82	$44.56	$45.00	$45.23	***$47.02***	$47.02
2023	$46.29	***$48.50***	$46.67	$47.69	***$48.50***	$46.28	$45.38	$46.75	$46.91	$44.11	$44.88	$44.66	$45.09	$48.50
2024	$45.88	$45.85	***$47.66***	$46.20	***$47.66***	$45.95	$44.35	$45.19	$45.48	$45.03	$45.85	$45.72	$45.64	$47.66
2025	$47.31	$48.17	$48.04	$47.46	***$49.00***	$46.99	$45.18	$46.67	$46.76	$46.87	$47.36	$47.53	$47.63	$49.00
2026	$49.79	$51.48	$49.26	$51.45	***$51.82***	$49.76	$48.27	$49.55	$49.17	$48.55	$49.44	$49.17	$49.58	$51.82
2027	$51.41	$52.23	$51.43	$51.37	***$53.65***	$51.63	$50.13	$51.61	$51.74	$49.86	$51.48	$50.74	$51.08	$53.65
2028	$52.60	$51.81	$54.00	$52.54	***$54.78***	$53.25	$51.38	$51.81	$52.80	$51.54	$53.06	$52.14	$52.06	$54.78
2029	$53.91	$54.45	$53.52	$54.21	***$55.62***	$53.74	$52.67	$53.53	$53.56	$52.69	$54.29	$54.37	$54.30	$55.62
2030	$54.58	***$55.91***	***$55.91***	$54.00	***$55.91***	$54.18	$51.77	$54.02	$54.28	$53.72	$54.48	$54.83	***$55.91***	$55.91
2031	$55.49	***$57.18***	***$57.18***	$54.08	***$57.18***	$53.77	$52.37	$52.80	$52.95	$56.99	***$57.18***	***$57.18***	$57.02	$57.18
2032	$56.66	$58.24	***$58.30***	$55.12	***$58.30***	$54.72	$54.74	$53.86	$54.08	$57.71	***$58.30***	***$58.30***	***$58.30***	$58.30

Energy Only costs are calculated by GRID and are capped at the IRP Resource Energy Cost

Denotes months with capped energy prices

Appendix B

Table 4
2011 IRP Resource Cost
CCCT (Dry "F" 2x1) - East Side Resource (4500')

Year	Estimated Capital Cost $/kW	Capital Cost at Real Levelized Rate $/kW-yr	Fixed O&M $/kW-yr	Variable O&M $/MWh	Total O&M at Expected CF $/kW-yr	Total Resource Fixed Costs $/kW-yr	Fuel Cost $/MMBtu	Total Resource Energy Cost $/MWh	Total Resource Costs $/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
CCCT (Dry "F" 2x1) - East Side Resource (4500')									
2010	$1,024	$85.71	$8.82	$7.95	$43.85	$129.56			
2011		$87.68	$9.02	$8.13	$44.84	$132.52			
2012		$89.00	$9.16	$8.25	$45.51	$134.51			
2013		$90.60	$9.32	$8.40	$46.33	$136.93			
2014		$92.32	$9.50	$8.56	$47.22	$139.54			
2015		$94.17	$9.69	$8.73	$48.16	$142.33			
2016		$95.96	$9.87	$8.90	$49.09	$145.05	$4.67	$32.92	$65.84
2017		$97.78	$10.06	$9.07	$50.02	$147.80	$4.95	$34.90	$68.44
2018		$99.64	$10.25	$9.24	$50.96	$150.60	$5.42	$38.21	$72.39
2019		$101.43	$10.43	$9.41	$51.89	$153.32	$5.89	$41.52	$76.32
2020		$103.15	$10.61	$9.57	$52.78	$155.93	$5.74	$40.47	$75.86
2021		$105.01	$10.80	$9.74	$53.72	$158.73	$6.07	$42.79	$78.81
2022		$106.90	$10.99	$9.92	$54.70	$161.60	$6.67	$47.02	$83.69
2023		$108.82	$11.19	$10.10	$55.69	$164.51	$6.88	$48.50	$85.84
2024		$110.78	$11.39	$10.28	$56.69	$167.47	$6.76	$47.66	$85.67
2025		$112.77	$11.60	$10.47	$57.73	$170.50	$6.95	$49.00	$87.69
2026		$114.80	$11.81	$10.66	$58.78	$173.58	$7.35	$51.82	$91.21
2027		$116.98	$12.03	$10.86	$59.88	$176.86	$7.61	$53.65	$93.79
2028		$119.20	$12.26	$11.07	$61.04	$180.24	$7.77	$54.78	$95.69
2029		$121.46	$12.49	$11.28	$62.19	$183.65	$7.89	$55.62	$97.30
2030		$123.77	$12.73	$11.49	$63.36	$187.13	$7.93	$55.91	$98.38
2031		$126.25	$12.98	$11.72	$64.62	$190.87	$8.11	$57.18	$100.50
2032		$128.65	$13.23	$11.94	$65.84	$194.49	$8.27	$58.30	$102.44
2033		$131.09	$13.48	$12.17	$67.10	$198.19	$8.43	$59.43	$104.41
2034		$133.71	$13.75	$12.41	$68.43	$202.14	$8.59	$60.56	$106.44
2035		$136.25	$14.01	$12.65	$69.75	$206.00	$8.76	$61.76	$108.51
2036		$138.84	$14.28	$12.89	$71.08	$209.92	$8.92	$62.89	$110.53

Sources, Inputs and Assumptions

Source: (a)(c)(d)		Plant Costs - 2011 IRP - [Table 6.1 & 6.3]
	(b)	= (a) x 0.0837
	(e)	= (d) x (8.76 x 50.3%) + (c)
	(f)	= (b) + (e)
	(g)	Table 5 - Burnertip Natural Gas Price Forecast
	(h)	= 7050 x (g) / 1000
	(i)	= (f) / (8.76 x 'Capacity Factor') + (h)

Appendix B

Table 4
2011 IRP Resource Cost
CCCT (Dry "F" 2x1) - East Side Resource (4500')

CCCT (Dry "F" 2x1) - East Side Resource (4500')

CCCT Statistics	MW	Percent	Cap Cost	Fixed
CCCT (Dry "F" 2x1) *	512	85.8%	$1,104	$10.19
CCCT Duct Firing (Dry "F" 2x1)	85	14.2%	$538	$0.50
Capacity Weighted	597	100.0%	$1,024	$8.82

CCCT Statistics	MW	CF	aMW	Percent	Variable	Heat Rate
CCCT (Dry "F" 2x1) *	512	56.0%	287	95.5%	$8.02	6,963
CCCT Duct Firing (Dry "F" 2x1)	85	16.0%	14	4.5%	6.54	8,934
Energy Weighted	597	50.3%	300	100.0%	$7.95	7,050
						Rounded

CCCT	Duct Firing	Plant Costs - 2011 IRP - [Table 6.1 & 6.3]
512	85	MW Plant capacity
$1,104	$538	Plant capacity cost
$10.19	$0.50	Fixed O&M plus on-going capital cost
$8.02	$6.54	Total Variable O&M Costs in $/MWh includes Fixed Pipeline Costs (See Below)
$3.35	$0.55	Variable O&M Costs in $/MWh
$4.67	$5.99	Fixed Pipeline Costs in $/MWH
6,963	8,934	Heat Rate in btu/kWh
8.37%	8.37%	Payment Factor
56%	16%	Capacity Factor
	50.3%	Energy Weighted Capacity Factor
	88.2%	Capacity Factor - On-peak 50.3% / 57% (percent of hours on-peak)

Company Official Inflation Forecast Dated 2011 December

2010	1.3%	2019	1.8%	2028	1.9%
2011	2.3%	2020	1.7%	2029	1.9%
2012	1.5%	2021	1.8%	2030	1.9%
2013	1.8%	2022	1.8%	2031	2.0%
2014	1.9%	2023	1.8%	2032	1.9%
2015	2.0%	2024	1.8%	2033	1.9%
2016	1.9%	2025	1.8%	2034	2.0%
2017	1.9%	2026	1.8%	2035	1.9%
2018	1.9%	2027	1.9%	2036	1.9%

Appendix B

Table 5
Burnertip Natural Gas Price Forecast
Utah Compliance Filing 2012.Q1 - 100 MW and 85% Capacity Factor

Year	PacifiCorp Delivered East Side Natural Gas Fuel Cost
2016	$4.67
2017	$4.95
2018	$5.42
2019	$5.89
2020	$5.74
2021	$6.07
2022	$6.67
2023	$6.88
2024	$6.76
2025	$6.95
2026	$7.35
2027	$7.61
2028	$7.77
2029	$7.89
2030	$7.93
2031	$8.11
2032	$8.27
2033	$8.43
2034	$8.59
2035	$8.76
2036	$8.92

OFPC Forecast dated Dec 30, 2011

Appendix C

Utah Quarterly Compliance Filing
Step Study between 2011.Q4 and 2012.Q1 Compliance Filing
Total Avoided Cost Prices $/MWH (1) (4)

Year	2011.Q4 Filed	Official Forward Price Curve (2)	2012.Q1 Proposed
2013	$35.18	$30.60	$31.31
2014	$37.26	$32.72	$32.85
2015	$38.24	$33.40	$34.05
2016	$45.88	$42.07	$41.97
2017	$56.50	$52.01	$51.75
2018	$59.48	$55.73	$56.37
2019	$62.11	$59.80	$59.75
2020	$60.65	$57.76	$58.49
2021	$67.30	$62.68	$62.69
2022	$67.91	$66.67	$66.82
2023	$69.14	$68.36	$68.72
2024	$70.78	$68.54	$68.45
2025	$72.29	$70.49	$70.41
2026	$76.30	$73.39	$73.38
2027	$79.17	$75.62	$75.48
2028	$81.06	$77.12	$77.10
2029	$83.28	$79.07	$78.98
2030	$84.61	$80.34	$80.27
2031	$85.96	$81.73	$81.61
2032	$87.23 x	$83.04 x	$83.71
20 Year Nominal Levelized Payment at 7.17% Discount Rate (3)			
	$59.74	$56.17	$56.37

x Extrapolated
(1) Studies are sequential. The order of the studies would effect the price impact.
(2) Official Forward Price Curve Dated December 31, 2011
(3) 2011 IRP Discount Rate
(4) Capacity costs are allocated assuming an 85% capacity factor.

Appendix C

Utah Quarterly Compliance Filing
Step Study between 2011.Q4 and 2012.Q1 Compliance Filing
Avoided Cost Impact of Changing Assumptions $/MWH (1) (4)

Year	Official Forward Price Curve (2)	All Other Updates	Total Change
2013	($4.58)	$0.71	($3.87)
2014	($4.54)	$0.13	($4.41)
2015	($4.84)	$0.65	($4.19)
2016	($3.81)	($0.10)	($3.91)
2017	($4.49)	($0.26)	($4.75)
2018	($3.75)	$0.64	($3.11)
2019	($2.31)	($0.05)	($2.36)
2020	($2.89)	$0.73	($2.16)
2021	($4.62)	$0.01	($4.61)
2022	($1.24)	$0.15	($1.09)
2023	($0.78)	$0.36	($0.42)
2024	($2.24)	($0.09)	($2.33)
2025	($1.80)	($0.08)	($1.88)
2026	($2.91)	($0.01)	($2.92)
2027	($3.55)	($0.14)	($3.69)
2028	($3.94)	($0.02)	($3.96)
2029	($4.21)	($0.09)	($4.30)
2030	($4.27)	($0.07)	($4.34)
2031	($4.23)	($0.12)	($4.35)
2032	($4.19)	$0.67	($3.52)
20 Year Nominal Levelized Payment at 7.17% Discount Rate (3)	($3.57)	$0.20	($3.37)

(1) Studies are sequential. The order of the studies would effect the price impact.
(2) Official Forward Price Curve Dated December 31, 2011
(3) 2011 IRP Discount Rate
(4) Capacity costs are allocated assuming an 85% capacity factor.

Appendix C

Utah Quarterly Compliance Filing
Step Study between 2011.Q4 and 2012.Q1 Compliance Filing
GRID Calculated Energy Avoided Cost Prices $/MWH (1)

Year	2011.Q4 Filed	Official Forward Price Curve (2)	All Other Updates
2013	$35.18	$30.60	$31.31
2014	$37.26	$32.72	$32.85
2015	$38.24	$33.40	$34.05
2016	$34.55	$30.74	$30.64
2017	$36.65	$32.16	$31.90
2018	$39.25	$35.50	$36.14
2019	$41.52	$39.21	$39.16
2020	$39.77	$36.88	$37.61
2021	$45.98	$41.36	$41.37
2022	$46.21	$44.97	$45.12
2023	$47.05	$46.27	$46.63
2024	$48.35	$46.11	$46.02
2025	$49.39	$47.59	$47.51
2026	$52.99	$50.08	$50.07
2027	$55.42	$51.87	$51.73
2028	$56.92	$52.98	$52.96
2029	$58.62	$54.41	$54.32
2030	$59.48	$55.21	$55.14
2031	$60.33	$56.10	$55.98
2032	$61.18 x	$56.99 x	$57.66
20- Year Nominal Levelized Payment at 7.17% Discount Rate (3)	$43.89	$40.32	$40.51

x Extrapolated
(1) Studies are sequential. The order of the studies would effect the price impact.
(2) Official Forward Price Curve Dated December 31, 2011
(3) 2011 IRP Discount Rate

Appendix C

Utah Quarterly Compliance Filing
Step Study between 2011.Q4 and 2012.Q1 Compliance Filing
Capacity Avoided Cost Prices

	$/kW-Year		$/MWH (1)		$/MWH
Year	**2012.Q1**	**2011.Q4**	**2012.Q1**	**2011.Q4**	**Difference**
2013	-	-	-	-	-
2014	-	-	-	-	-
2015	-	-	-	-	-
2016	84.61	84.61	11.33	11.33	0.00
2017	147.80	147.80	19.85	19.85	0.00
2018	150.60	150.60	20.23	20.23	0.00
2019	153.32	153.32	20.59	20.59	0.00
2020	155.93	155.93	20.88	20.88	0.00
2021	158.73	158.73	21.32	21.32	0.00
2022	161.60	161.60	21.70	21.70	0.00
2023	164.51	164.51	22.09	22.09	0.00
2024	167.47	167.47	22.43	22.43	0.00
2025	170.50	170.50	22.90	22.90	0.00
2026	173.58	173.58	23.31	23.31	0.00
2027	176.86	176.86	23.75	23.75	0.00
2028	180.24	180.24	24.14	24.14	0.00
2029	183.65	183.65	24.66	24.66	0.00
2030	187.13	187.13	25.13	25.13	0.00
2031	190.87	190.87	25.63	25.63	0.00
2032	194.49	$194.49	26.05	26.05	0.00
Nominal Levelized Payment at 7.17% Discount Rate (2)					
2013 - 2032	$118.16		$15.86		$0.00

(1) Capacity costs are allocated assuming an 85% capacity factor.
(2) 2011 IRP Discount Rate