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May 30, 2013

Via Electronic and Priority Mail

Public Utility Commission of Oregon
Attn: Filing Center
P.O. Box 2148
Salem, OR 97308-2148
puc.filingcenter@state.or.us

Re: OPUC Docket No. UM 1610

Attention Filing Center:

Enclosed for filing in the above-captioned docket are an original and five copies of *Hearing Exhibits OneEnergy/400-411.* These Exhibits were admitted by Administrative Law Judge Pines at hearing on May 23, 2013.

OneEnergy/400	PacifiCorp Response to OneEnergy Data Request No. 5.1 (confidential attachment)
OneEnergy/401	Attachment to PacifiCorp Response to CREA Data Request 1.2
OneEnergy/402	PacifiCorp Response to OneEnergy Data Request No. 5.2 (confidential attachment)
OneEnergy/403	PacifiCorp Response to OneEnergy Data Request No. 5.3
OneEnergy/404	PacifiCorp Response to OneEnergy Data Request No. 5.4
OneEnergy/405	PacifiCorp Response to OneEnergy Data Request No. 5.6
OneEnergy/406	PacifiCorp Response to OneEnergy Data Request No. 5.7
OneEnergy/407	PacifiCorp Response to OneEnergy Data Request No. 5.9
OneEnergy/408	PacifiCorp Response to OneEnergy Data Request No. 5.11
OneEnergy/409	PacifiCorp Response to OneEnergy Data Request No. 5.12
OneEnergy/410	PacifiCorp Response to OneEnergy Data Request No. 5.13
OneEnergy/411	PacifiCorp Response to OneEnergy Data Request No. 5.8

Please date stamp the extra copy of this letter and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

Dana Hurley
Office Manager

cc: UM 1610 Service List

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit

PacifiCorp's Response to OneEnergy's Data Request 5.1

UM 1610/PacifiCorp
May 21, 2013
OneEnergy Data Request 5.1

OneEnergy Data Request 5.1

In its compliance filing for Commission Order No. 11-505, PacifiCorp explained how it calculated its proposed renewable avoided cost:

> For the period of resource deficiency, the Company used the capital costs assumed in the 2011 IRP.[1] For example, the total capital cost of the Wyoming wind facility assumes a $/kilowatt ("kW") of $2,239.[2] This capital cost amount, plus fixed operation and maintenance costs are then used to calculate a $/megawatt-hour ("MWh") based on the expected annual capacity factor (35 percent) of the Wyoming wind resource. Lastly, the Company utilized a Mid-C market price weighting to develop an on-and-off peak deficiency period price.

Direct Testimony of Kelcey Brown, PAC/100, Brown/6-7, OPUC Docket No. UM 1396 (Feb. 13, 2012) (footnotes in original).

(a) Did Ms. Brown intend to say "Lastly, the Company utilized a Mid-C market price weighting to develop an on- and off-peak *sufficiency* period price."?

(b) Please admit or deny that Ms. Brown's statement accurately describes how PacifiCorp calculated its proposed renewable avoided cost it proposes for implementation in this proceeding. If PacifiCorp denies, please explain.

(c) Please provide work papers showing how PacifiCorp arrived at $2,239/kW Total Capital Cost of the Wyoming wind facility.

Response to OneEnergy Data Request 5.1

(a) Yes. The correct wording should have been "*sufficiency* period price."

(b) Yes. Please refer to the Company's response to CREA Data Request 1.2, which provides an attachment showing the detailed calculation.

(c) Please refer to Confidential Attachment OneEnergy 5.1.

The confidential attachment is designated as confidential under Protective Order No. 12-461 and may only be disclosed to qualified persons as defined in that order.

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[1] *See* PacifiCorp's 2011 IRP, at Page 117, Table 6.3.

[2] *Id.* All figures from the 2011 IRP are reflected in 2010 real dollars. For the applicable start date of the deficiency period (2018) the Company escalated the 2011 IRP capital cost estimates using the official inflation forecast dated December 2011.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit

Attachment to PacifiCorp's Response to Community Renewable Energy Association Data Request 1.2

Exhibit 1
Fixed Avoided Cost Prices (1)

Year	Capacity Price	Capacity Cost Allocated to On-Peak Hours	Energy Only Price	On-Peak	Off-Peak
	$/kW-yr	($/MWh)	$/MWh	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)
		(a) /(8.76 x 88.6% x 57%)		(b) + (c)	(b)
2012	Market Based Prices 2012 through 2015			$29.41	$22.57
2013				$36.13	$26.69
2014				$39.31	$29.69
2015				$42.56	$31.44
2016	$122.45	$27.68	$39.33	$67.01	$39.33
2017	$124.78	$28.21	$41.66	$69.87	$41.66
2018	$127.15	$28.74	$44.68	$73.42	$44.68
2019	$129.44	$29.26	$47.57	$76.83	$47.57
2020	$131.64	$29.76	$46.75	$76.51	$46.75
2021	$134.01	$30.29	$49.15	$79.44	$49.15
2022	$136.42	$30.84	$53.16	$84.00	$53.16
2023	$138.87	$31.39	$55.21	$86.60	$55.21
2024	$141.36	$31.95	$54.48	$86.43	$54.48
2025	$143.91	$32.53	$56.12	$88.65	$56.12
2026	$146.50	$33.12	$58.60	$91.72	$58.60
2027	$149.28	$33.74	$60.82	$94.56	$60.82
2028	$152.12	$34.39	$62.54	$96.93	$62.54
2029	$155.01	$35.04	$63.99	$99.03	$63.99
2030	$157.96	$35.71	$64.74	$100.45	$64.74
2031	$161.12	$36.42	$65.71	$102.13	$65.71
2032	$164.18	$37.11	$66.96	$104.07	$66.96
2033	$167.30	$37.82	$68.20	$106.02	$68.20
2034	$170.65	$38.57	$69.59	$108.16	$69.59
2035	$173.89	$39.31	$70.85	$110.16	$70.85

(1) The avoided cost payment in all contracted years will be reduced by an integration charge of $9.70/MWh for intermittent resources.

Columns
- (a) Full Fixed Cost of a Proxy CCCT less capitalized energy
- (b) 88.6% is the on-peak capacity factor of the Proxy Resource
- (c) Fuel and Capitalized Energy Cost of the Proxy CCCT
- (d) 2012-2015 On-Peak Market Prices
- (e) 2012-2015 Off-Peak Market Prices

Exhibit 2
Gas Market Indexed Avoided Cost Prices (1)

Year	Avoided Firm Capacity Costs	Total Avoided Energy Cost	West Side Raw Gas Price (1)	Proxy CCCT Raw Fuel Index	Fixed Prices On-Peak	Fixed Prices Off-Peak	On-Peak Capacity Adder	Off-Peak Energy Adder
	($/kW-yr)	($/MWh)	$/MMBtu	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
				(c) x 6.960			(a) /(8.76 x 88.6% x 57%)	(b) - (d)
2012	Market Based Prices 2012 through 2015				$29.41	$22.57	Market Based Prices 2012 through 2015	
2013					$36.13	$26.69		
2014					$39.31	$29.69		
2015					$42.56	$31.44		
2016	$122.45	$39.33	$4.66	$32.43			$27.68	$6.90
2017	$124.78	$41.66	$4.95	$34.45			$28.21	$7.21
2018	$127.15	$44.68	$5.38	$37.44			$28.74	$7.24
2019	$129.44	$47.57	$5.79	$40.30			$29.26	$7.27
2020	$131.64	$46.75	$5.66	$39.39			$29.76	$7.36
2021	$134.01	$49.15	$5.98	$41.62			$30.29	$7.53
2022	$136.42	$53.16	$6.53	$45.45			$30.84	$7.71
2023	$138.87	$55.21	$6.78	$47.19			$31.39	$8.02
2024	$141.36	$54.48	$6.66	$46.35			$31.95	$8.13
2025	$143.91	$56.12	$6.87	$47.82			$32.53	$8.30
2026	$146.50	$58.60	$7.21	$50.18			$33.12	$8.42
2027	$149.28	$60.82	$7.49	$52.13			$33.74	$8.69
2028	$152.12	$62.54	$7.69	$53.52			$34.39	$9.02
2029	$155.01	$63.99	$7.85	$54.64			$35.04	$9.35
2030	$157.96	$64.74	$7.92	$55.12			$35.71	$9.62
2031	$161.12	$65.71	$8.06	$56.10			$36.42	$9.61
2032	$164.18	$66.96	$8.21	$57.14			$37.11	$9.82
2033	$167.30	$68.20	$8.37	$58.26			$37.82	$9.94
2034	$170.65	$69.59	$8.53	$59.37			$38.57	$10.22
2035	$173.89	$70.85	$8.70	$60.55			$39.31	$10.30

(1) The avoided cost payment in all contracted years will be reduced by an integration charge of $9.70/MWh for intermittent resources.

Columns
- (a) Fixed Cost of a Proxy CCCT less Capitalized Energy included in Energy Component
- (b) Fuel and Capitalized Energy Cost of the Proxy CCCT
- (c) Company's Official Price Forecast (December 2011) - Fuel Only Gas Price
- (d) 6.960 MMBtu/MWh Proxy CCCT Heat Rate
- (e) 2012-2015 On-Peak Market Prices
- (f) 2012-2015 Off-Peak Market Prices
- (g) 88.6% is the on-peak capacity factor of the Proxy Resource

Note: (1) Gas Prices are the average of Opal, Sumas and Stanfield Gas Indexes
QFs are paid based on Raw Index Costs. Delivery to burner tip is included in the "Off-Peak Energy Adder"

Exhibit 3

Banded Gas Indexed Avoided Cost Prices (1)

Year	Avoided Firm Capacity Costs	Total Avoided Energy Cost	West Side Raw Gas Price (1)	Proxy CCCT Raw Fuel Index	Fixed Prices On-Peak	Fixed Prices Off-Peak	On-Peak Capacity Adder	Off-Peak Energy Adder	Fuel Index Floor 90%	Fuel Index Ceiling 110%
	($/kW-yr)	($/MWh)	$/MMBtu	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(j)	(k)
				(c) x 6.960			(a) /(8.76 x 88.6% x 57%)	(b) - (d)	(d) x 90%	(d) x 110%
2012					$29.41	$22.57				
2013	Market Based Prices				$36.13	$26.69	Market Based Prices			
2014	2012 through 2015				$39.31	$29.69	2012 through 2015			
2015					$42.56	$31.44				
2016	$122.45	$39.33	$4.66	$32.43			$27.68	$6.90	$29.19	$35.67
2017	$124.78	$41.66	$4.95	$34.45			$28.21	$7.21	$31.01	$37.90
2018	$127.15	$44.68	$5.38	$37.44			$28.74	$7.24	$33.70	$41.18
2019	$129.44	$47.57	$5.79	$40.30			$29.26	$7.27	$36.27	$44.33
2020	$131.64	$46.75	$5.66	$39.39			$29.76	$7.36	$35.45	$43.33
2021	$134.01	$49.15	$5.98	$41.62			$30.29	$7.53	$37.46	$45.78
2022	$136.42	$53.16	$6.53	$45.45			$30.84	$7.71	$40.91	$50.00
2023	$138.87	$55.21	$6.78	$47.19			$31.39	$8.02	$42.47	$51.91
2024	$141.36	$54.48	$6.66	$46.35			$31.95	$8.13	$41.72	$50.99
2025	$143.91	$56.12	$6.87	$47.82			$32.53	$8.30	$43.04	$52.60
2026	$146.50	$58.60	$7.21	$50.18			$33.12	$8.42	$45.16	$55.20
2027	$149.28	$60.82	$7.49	$52.13			$33.74	$8.69	$46.92	$57.34
2028	$152.12	$62.54	$7.69	$53.52			$34.39	$9.02	$48.17	$58.87
2029	$155.01	$63.99	$7.85	$54.64			$35.04	$9.35	$49.18	$60.10
2030	$157.96	$64.74	$7.92	$55.12			$35.71	$9.62	$49.61	$60.63
2031	$161.12	$65.71	$8.06	$56.10			$36.42	$9.61	$50.49	$61.71
2032	$164.18	$66.96	$8.21	$57.14			$37.11	$9.82	$51.43	$62.85
2033	$167.30	$68.20	$8.37	$58.26			$37.82	$9.94	$52.43	$64.09
2034	$170.65	$69.59	$8.53	$59.37			$38.57	$10.22	$53.43	$65.31
2035	$173.89	$70.85	$8.70	$60.55			$39.31	$10.30	$54.50	$66.61

(1) The avoided cost payment in all contracted years will be reduced by an integration charge of $9.70/MWh for intermittent resources.

Columns
- (a) Fixed Cost of a Proxy CCCT less Capitalized Energy included in Energy Component
- (b) Fuel and Capitalized Energy Cost of the Proxy CCCT
- (c) Company's Official Price Forecast (December 2011) - Fuel Only Gas Price
- (d) 6.960 MMBtu/MWh Proxy CCCT Heat Rate
- (e) 2012-2015 On-Peak Market Prices
- (f) 2012-2015 Off-Peak Market Prices
- (g) 88.6% is the on-peak capacity factor of the Proxy Resource

Note: (1) Gas Prices are the average of Opal, Sumas and Stanfield Gas Indexes
QFs are paid based on Raw Index Costs. Delivery to burner tip is included in the "Off-Peak Energy Adder"

Exhibit 4
Fixed Renewable Avoided Cost Prices
$/MWh

Year	Renewable Price	Proxy Resource / Mid-C Price Shaping		On-Peak	Off-Peak
		On-Peak	Off-Peak		
	(a)	(b)	(c)	(d)	(e)
		(a) /(8.76 x 88.6% x 57%)		(a) x (b)	(a) x (c)
2012	Market Based Prices 2012 through 2017 (1)			$29.41	$22.57
2013				$36.13	$26.69
2014				$39.31	$29.69
2015				$42.56	$31.44
2016				$46.06	$33.34
2017				$49.56	$35.14
2018	$60.62	1.1262	0.8401	$68.27	$50.93
2019	$61.72	1.1091	0.8610	$68.45	$53.14
2020	$62.76	1.1078	0.8613	$69.52	$54.06
2021	$63.89	1.0800	0.8986	$69.00	$57.41
2022	$65.03	1.0787	0.9002	$70.15	$58.54
2023	$66.21	1.0777	0.9019	$71.36	$59.72
2024	$67.41	1.0748	0.9045	$72.45	$60.97
2025	$68.62	1.0738	0.9060	$73.68	$62.17
2026	$69.86	1.0728	0.9071	$74.94	$63.37
2027	$71.18	1.0689	0.9124	$76.09	$64.94
2028	$72.53	1.0697	0.9119	$77.58	$66.14
2029	$73.90	1.0662	0.9162	$78.79	$67.71
2030	$75.31	1.0643	0.9178	$80.15	$69.11
2031	$76.81	1.0666	0.9138	$81.92	$70.19
2032	$78.27	1.0634	0.9197	$83.23	$71.98
2033	$79.76	1.0609	0.9225	$84.62	$73.58
2034	$81.36	1.0606	0.9237	$86.28	$75.15
2035	$82.91	1.0586	0.9260	$87.77	$76.77

(1) The avoided cost payment during the period of renewable sufficiency (market based prices) will be reduced by an integration charge of $9.70/MWh for intermittent resources.

Columns
- (a) Renewable Resource Cost - based on 2011 IRP Wind Resource
- (b) Ratio Mid-Columbia market On-Peak to annual prices
- (c) Ratio Mid-Columbia market Off-Peak to annual prices
- (d) 2012-2017 On-Peak Market Prices
- (e) 2012-2017 Off-Peak Market Prices

Table 1
IRP Preferred Portfolio
Excerpt from 2011 IRP Table 8.16

		Capacity (MW)								
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019
East										
	CCCT F 2x1 (Utah North, Utah South)	-	-	-	625	-	597	-	-	-
	CCCT H (Utah South)	-	-	-	-	-	-	-	-	475
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-
	Wind, Wyoming, 35% Capacity Factor	-	-	-	-	-	-	-	300	300
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	DSM, Class 1 Total	6	70	-	20	91	-	-	-	-
	DSM, Class 2 Total	47	53	46	48	51	54	56	58	60
	Micro Solar - Water Heating	-	2.6	2.6	2.6	2.6	2.6	2.6	2.6	-
	FOT Mead Q3 HLH	-	168.2	264.0	264.0	99.1	24.9	-	-	-
	FOT Utah Q3 HLH	200.0	200.0	203.9	26.1	250.0	-	72.3	217.0	-
	FOT Mona Q3 HLH	-	-	150.0	300.0	300.0	300.0	300.0	300.0	300
West										
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
	DSM, Class 1 Total 2/	-	-	57.0	-	6.4	-	-	-	-
	DSM, Class 2 Total	60.7	61.4	65.0	69.8	71.0	70.0	69.7	61.7	62
	OR Solar Capacity Standard	-	2.0	2.0	2.0	3.0	-	-	-	-
	OR Solar Incentive Program Pilot	3.9	2.5	2.5	1.0	-	-	-	-	-
	Micro Solar - Water Heating	-	1.8	1.8	1.8	1.8	1.8	1.8	1.0	-
	FOT COB Q3 HLH	150	150	150	150	50	-	-	-	-
	FOT Mid Columbia Q3 HLH	-	400	400	400	400	400	400	400	395
	FOT Mid Columbia Q3 HLH, 10% price premium	-	271	211	-	-	-	-	-	-
	FOT Oregon Q3 HLH	-	50	50	50	50	50	50	50	-
	Annual Additions, Long Term Resources	134	217	187	776	232	749	136	437	902
	Annual Additions, Short Term Resources	350	1,240	1,429	1,190	1,149	775	822	967	695
	Total Annual Additions	484	1,457	1,616	1,966	1,381	1,524	958	1,404	1,597

1/ Front office transaction amounts reflect one-year transaction periods, and are to additive.

2/ PacifiCorp excludes from the portfolio new programs under a five-megawatt implementation feasibility threshold.

Table 2
Avoided Costs ($/MWh)
Energy Prices 2012 through 2015

Year	Winter Season					Summer Season				Winter Season		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-Peak (HLH Market Purchase)												
2012	29.22	27.75	26.25	25.37	22.25	19.14	31.83	35.18	33.50	31.51	33.57	37.33
2013	36.57	34.85	32.09	32.16	26.43	23.16	37.54	44.14	42.08	38.18	41.92	44.41
2014	40.57	38.85	36.09	32.41	26.68	23.41	41.54	48.14	46.08	42.68	46.42	48.91
2015	43.82	42.10	39.34	35.66	29.93	26.66	44.79	51.39	49.33	45.93	49.67	52.16
2016	47.32	45.60	42.84	39.16	33.43	30.16	48.29	54.89	52.83	49.43	53.17	55.66
2017	50.82	49.10	46.34	42.66	36.93	33.66	51.79	58.39	56.33	52.93	56.67	59.16
Off-Peak (LLH Market Purchase)												
2012	26.12	24.75	22.00	19.20	12.00	4.80	18.87	25.97	28.67	27.44	30.09	30.98
2013	31.34	29.61	25.30	20.21	12.54	11.51	21.75	29.66	33.34	32.90	34.65	37.45
2014	34.84	33.11	28.80	21.71	14.04	13.01	25.00	32.91	36.59	36.65	38.40	41.20
2015	36.59	34.86	30.55	23.46	15.79	14.76	26.75	34.66	38.34	38.40	40.15	42.95
2016	38.49	36.76	32.45	25.36	17.69	16.66	28.65	36.56	40.24	40.30	42.05	44.85
2017	40.29	38.56	34.25	27.16	19.49	18.46	30.45	38.36	42.04	42.10	43.85	46.65
Combined												
2012	27.79	26.47	24.47	22.63	17.73	13.08	25.83	31.31	31.24	29.80	32.02	34.39
2013	34.26	32.60	29.10	27.11	20.31	17.98	30.58	38.07	38.00	35.97	38.68	41.19
2014	38.04	36.39	32.88	27.89	21.11	18.79	34.25	41.43	41.86	40.15	42.67	45.51
2015	40.63	39.00	35.47	30.50	23.39	21.63	36.84	44.01	44.44	42.77	45.22	48.10
2016	43.24	41.84	38.49	33.33	26.15	24.46	39.21	47.20	47.23	45.40	48.22	50.89
2017	45.95	44.58	41.28	35.77	29.24	27.24	41.92	49.99	49.97	48.16	50.96	53.37

Annual Average

	On-Peak	Off-Peak	Combined
2012	$29.41	$22.57	$26.40
2013	$36.13	$26.69	$31.99
2014	$39.31	$29.69	$35.08
2015	$42.56	$31.44	$37.67
2016	$46.06	$33.34	$40.47
2017	$49.56	$35.14	$43.20

Source: Official Price Forecast - December 2011
Mid-Columbia Market Prices
Prices for 2016 apply for January through May 2016

Table 3
Capitalized Energy Costs

Year	Combined Cycle CT Fixed Costs	Simple Cycle CT Fixed Costs	Capitalized Energy Costs	Capitalized Energy Costs 50.5% CF
	($/kW-yr)	($/kW-yr)	($/kW-yr)	($/MWh)
	(a)	(b)	(c)	(d)
			((a) - (b))	(c)/(8.760 x 50.5%)
2016	$145.89	$122.45	$23.44	$5.30
2017	$148.66	$124.78	$23.88	$5.40
2018	$151.46	$127.15	$24.31	$5.50
2019	$154.20	$129.44	$24.76	$5.60
2020	$156.82	$131.64	$25.18	$5.69
2021	$159.62	$134.01	$25.61	$5.79
2022	$162.51	$136.42	$26.09	$5.90
2023	$165.43	$138.87	$26.56	$6.00
2024	$168.38	$141.36	$27.02	$6.11
2025	$171.43	$143.91	$27.52	$6.22
2026	$174.51	$146.50	$28.01	$6.33
2027	$177.84	$149.28	$28.56	$6.46
2028	$181.22	$152.12	$29.10	$6.58
2029	$184.68	$155.01	$29.67	$6.71
2030	$188.18	$157.96	$30.22	$6.83
2031	$191.95	$161.12	$30.83	$6.97
2032	$195.60	$164.18	$31.42	$7.10
2033	$199.29	$167.30	$31.99	$7.23
2034	$203.27	$170.65	$32.62	$7.37
2035	$207.11	$173.89	$33.22	$7.51

Columns

(a) Table 8 Column (f)
(b) Table 8 Column (f)
(d) 50.5% CCCT Energy Weighted Capacity Factor - Table 8 page 3

Table 4
Total Avoided Energy Cost

Year	Combined Cycle Gas Price	Combined Cycle Energy Cost	Capitalized Energy Costs 50.5% CF	Total Avoided Energy Cost
	($/MMBtu)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)
		(a) x 6.960		(b) + (c)
2016	$4.89	$34.03	$5.30	$39.33
2017	$5.21	$36.26	$5.40	$41.66
2018	$5.63	$39.18	$5.50	$44.68
2019	$6.03	$41.97	$5.60	$47.57
2020	$5.90	$41.06	$5.69	$46.75
2021	$6.23	$43.36	$5.79	$49.15
2022	$6.79	$47.26	$5.90	$53.16
2023	$7.07	$49.21	$6.00	$55.21
2024	$6.95	$48.37	$6.11	$54.48
2025	$7.17	$49.90	$6.22	$56.12
2026	$7.51	$52.27	$6.33	$58.60
2027	$7.81	$54.36	$6.46	$60.82
2028	$8.04	$55.96	$6.58	$62.54
2029	$8.23	$57.28	$6.71	$63.99
2030	$8.32	$57.91	$6.83	$64.74
2031	$8.44	$58.74	$6.97	$65.71
2032	$8.60	$59.86	$7.10	$66.96
2033	$8.76	$60.97	$7.23	$68.20
2034	$8.94	$62.22	$7.37	$69.59
2035	$9.10	$63.34	$7.51	$70.85

Columns

(a) Table 9 Column (b)
(b) 6.960 MWh/MMBtu Heat Rate - Table 8
(c) Table 3 Column (d)

Table 5
Total Avoided Cost

Year	Avoided Firm Capacity Costs	Total Avoided Energy Cost	Total Avoided Costs At Stated Capacity Factor		
			75%	85%	90%
	($/kW-yr)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)	(e)
			(b)+((a)/8.76 x 0.75)	(b)+((a)/8.76 x 0.85)	(b)+((a)/8.76 x 0.9)
2016	$122.45	$39.33	$57.97	$55.78	$54.86
2017	$124.78	$41.66	$60.65	$58.42	$57.49
2018	$127.15	$44.68	$64.03	$61.76	$60.81
2019	$129.44	$47.57	$67.27	$64.95	$63.99
2020	$131.64	$46.75	$66.79	$64.43	$63.45
2021	$134.01	$49.15	$69.55	$67.15	$66.15
2022	$136.42	$53.16	$73.92	$71.48	$70.46
2023	$138.87	$55.21	$76.35	$73.86	$72.82
2024	$141.36	$54.48	$76.00	$73.46	$72.41
2025	$143.91	$56.12	$78.02	$75.45	$74.37
2026	$146.50	$58.60	$80.90	$78.27	$77.18
2027	$149.28	$60.82	$83.54	$80.87	$79.75
2028	$152.12	$62.54	$85.69	$82.97	$81.83
2029	$155.01	$63.99	$87.58	$84.81	$83.65
2030	$157.96	$64.74	$88.78	$85.95	$84.78
2031	$161.12	$65.71	$90.23	$87.35	$86.15
2032	$164.18	$66.96	$91.95	$89.01	$87.78
2033	$167.30	$68.20	$93.66	$90.67	$89.42
2034	$170.65	$69.59	$95.56	$92.51	$91.24
2035	$173.89	$70.85	$97.32	$94.20	$92.91

Columns

(a) Table 3 Column (b)

(b) Table 4 Column (d)

Table 6
On- & Off- Peak Energy Prices

Year	Avoided Firm Capacity Costs	Capacity Cost Allocated to On-Peak Hours	Total Avoided Energy Cost	On-Peak 4,993 Hours	Off-Peak 3,767 Hours
	($/kW-yr)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)	(e)
		(a) /(8.76 x 88.6% x 57%)		(b) + (c)	(c)
2016	$122.45	$27.68	$39.33	$67.01	$39.33
2017	$124.78	$28.21	$41.66	$69.87	$41.66
2018	$127.15	$28.74	$44.68	$73.42	$44.68
2019	$129.44	$29.26	$47.57	$76.83	$47.57
2020	$131.64	$29.76	$46.75	$76.51	$46.75
2021	$134.01	$30.29	$49.15	$79.44	$49.15
2022	$136.42	$30.84	$53.16	$84.00	$53.16
2023	$138.87	$31.39	$55.21	$86.60	$55.21
2024	$141.36	$31.95	$54.48	$86.43	$54.48
2025	$143.91	$32.53	$56.12	$88.65	$56.12
2026	$146.50	$33.12	$58.60	$91.72	$58.60
2027	$149.28	$33.74	$60.82	$94.56	$60.82
2028	$152.12	$34.39	$62.54	$96.93	$62.54
2029	$155.01	$35.04	$63.99	$99.03	$63.99
2030	$157.96	$35.71	$64.74	$100.45	$64.74
2031	$161.12	$36.42	$65.71	$102.13	$65.71
2032	$164.18	$37.11	$66.96	$104.07	$66.96
2033	$167.30	$37.82	$68.20	$106.02	$68.20
2034	$170.65	$38.57	$69.59	$108.16	$69.59
2035	$173.89	$39.31	$70.85	$110.16	$70.85

Columns

(a) Table 3 Column (b)
(b) Table 8 88.6% is the on-peak capacity factor of the Proxy Resource
(c) Table 4 Column (d)
Table 8 - CCCT (Wet "F" 2x1) - West Side Options (1500')

Table 7
Comparison between Proposed and Current Avoided Costs
$/MWh

Year	Total Avoided Costs (3)			Proposed Renewable Avoided Costs	
	Proposed Avoided Costs (1)	Oregon Approved Avoided Costs	Difference	Base Load	Intermittent
	(a)	(b)	(c) (a) - (b)	(d)	(e)
2012	$26.40	$52.23	($25.83)	$26.40	$16.70
2013	$31.99	$54.32	($22.33)	$31.99	$22.29
2014	$35.08	$72.29	($37.21)	$35.08	$25.38
2015	$37.67	$74.17	($36.50)	$37.67	$27.97
2016	$55.78	$76.30	($20.52)	$40.47	$30.77
2017	$58.42	$78.33	($19.91)	$43.20	$33.50
2018	$61.76	$80.81	($19.05)	$60.62	$60.62
2019	$64.95	$79.66	($14.71)	$61.72	$61.72
2020	$64.43	$80.37	($15.94)	$62.76	$62.76
2021	$67.15	$85.02	($17.87)	$63.89	$63.89
2022	$71.48	$89.96	($18.48)	$65.03	$65.03
2023	$73.86	$84.68	($10.82)	$66.21	$66.21
2024	$73.46	$81.56	($8.10)	$67.41	$67.41
2025	$75.45	$85.81	($10.36)	$68.62	$68.62
2026	$78.27	$87.51	($9.24)	$69.86	$69.86
2027	$80.87	$87.62	($6.75)	$71.18	$71.18
2028	$82.97	$91.04	($8.07)	$72.53	$72.53
2029	$84.81	$94.83	($10.02)	$73.90	$73.90
2030	$85.95	$94.83	($8.88)	$75.31	$75.31
2031	$87.35	$98.12	($10.77)	$76.81	$76.81
2032	$89.01			$78.27	$78.27
2033	$90.67			$79.76	$79.76
2034	$92.51			$81.36	$81.36
2035	$94.20			$82.91	$82.91
20 Year (2012 - 2031) levelized Price at 7.17% Discount Rate (2)					
$/MWh	$57.80	$77.25	($19.44)	$52.51	$48.11

Columns
(a) Table 2 Section 'Annual Average'
Table 5 Column (d)
(b) Avoided Costs Approved by the Commission and effective April 5, 2010
(d) 2012 - 2017 - Table 2, 2018 & therafter Table 11 Column (h)
2018 & thereafter - Table 11 Column (f)
(e) 2012 - 2017 - Column (d) less Integration Cost of $9.70/MWh
Note: (1) Avoided costs are presented at expected levels. Actual prices received by QFs will depend upon the pricing option selected.
(2) Discount Rate - 2011 IRP Discount Rate
(3) Total Avoided Costs with Capacity Costs included at 85% Capacity Factor

Table 8
Total Cost of Displaceable Resources

Year	Estimated Capital Cost $/kW (a)	Fixed Capital Cost at Real Levelized Rate $/kW-yr (b)	Fixed O&M $/kW-yr (c)	Variable O&M $/MWh (d)	Total O&M at Expected CF $/kW-yr (e)	Total Resource Fixed Costs $/kW-yr (f)
SCCT Frame (2 Frame "F") - West Side Options (1500')						
2010	$901	$75.77	$5.42	$15.32	$33.60	$109.37
2011		$77.51	$5.54	$15.67	$34.37	$111.88
2012		$78.67	$5.62	$15.91	$34.89	$113.56
2013		$80.09	$5.72	$16.20	$35.52	$115.61
2014		$81.61	$5.83	$16.51	$36.20	$117.81
2015		$83.24	$5.95	$16.84	$36.93	$120.17
2016		$84.82	$6.06	$17.16	$37.63	$122.45
2017		$86.43	$6.18	$17.49	$38.35	$124.78
2018		$88.07	$6.30	$17.82	$39.08	$127.15
2019		$89.66	$6.41	$18.14	$39.78	$129.44
2020		$91.18	$6.52	$18.45	$40.46	$131.64
2021		$92.82	$6.64	$18.78	$41.19	$134.01
2022		$94.49	$6.76	$19.12	$41.93	$136.42
2023		$96.19	$6.88	$19.46	$42.68	$138.87
2024		$97.92	$7.00	$19.81	$43.44	$141.36
2025		$99.68	$7.13	$20.17	$44.23	$143.91
2026		$101.47	$7.26	$20.53	$45.03	$146.50
2027		$103.40	$7.40	$20.92	$45.88	$149.28
2028		$105.36	$7.54	$21.32	$46.76	$152.12
2029		$107.36	$7.68	$21.73	$47.65	$155.01
2030		$109.40	$7.83	$22.14	$48.56	$157.96
2031		$111.59	$7.99	$22.58	$49.53	$161.12
2032		$113.71	$8.14	$23.01	$50.47	$164.18
2033		$115.87	$8.29	$23.45	$51.43	$167.30
2034		$118.19	$8.46	$23.92	$52.46	$170.65
2035		$120.44	$8.62	$24.37	$53.45	$173.89

Source: (a)(c)(d) Plant Costs - 2011 IRP - Table 6.2 & 6.6
(b) = (a) x Payment Factor
(e) = (d) x (8.76 x 21%) + (c)
(f) = (b) + (e)

		SCCT Frame (2 Frame "F") - West Side Options (1500')	
	405	MW Plant capacity	MW
$	901	Plant capacity cost	$/kW-yr
$	5.42	Fixed O&M plus on-going capital cost	$/kW-yr
$	15.32	Variable O&M and Other Costs	$/MWH
$	6.51	Variable O&M	$/MWH
$	8.81	Environmental Adders	$/MWH
	8.41%	Payment Factor	
	21%	Capacity Factor	

Table 8
Total Cost of Displaceable Resources

Year	Estimated Capital Cost $/kW (a)	Fixed Capital Cost at Real Levelized Rate $/kW-yr (b)	Fixed O&M $/kW-yr (c)	Variable O&M $/MWh (d)	Total O&M at Expected CF $/kW-yr (e)	Total Resource Fixed Costs $/kW-yr (f)	Fuel Cost $/MMBtu (g)	IRP Resource Energy Cost $/MWh (h)	Total Avoided Costs $/MWh (i)

CCCT (Wet "F" 2x1) - West Side Options (1500')

2010	$994	$83.20	$7.56	$8.93	$47.06	$130.26			
2011		$85.11	$7.73	$9.14	$48.16	$133.27			
2012		$86.39	$7.85	$9.28	$48.90	$135.29			
2013		$87.95	$7.99	$9.45	$49.79	$137.74			
2014		$89.62	$8.14	$9.63	$50.74	$140.36			
2015		$91.41	$8.30	$9.82	$51.74	$143.15			
2016		$93.15	$8.46	$10.01	$52.74	$145.89	$4.89	$34.03	$67.01
2017		$94.92	$8.62	$10.20	$53.74	$148.66	$5.21	$36.26	$69.86
2018		$96.72	$8.78	$10.39	$54.74	$151.46	$5.63	$39.18	$73.42
2019		$98.46	$8.94	$10.58	$55.74	$154.20	$6.03	$41.97	$76.83
2020		$100.13	$9.09	$10.76	$56.69	$156.82	$5.90	$41.06	$76.51
2021		$101.93	$9.25	$10.95	$57.69	$159.62	$6.23	$43.36	$79.44
2022		$103.76	$9.42	$11.15	$58.75	$162.51	$6.79	$47.26	$84.00
2023		$105.63	$9.59	$11.35	$59.80	$165.43	$7.07	$49.21	$86.61
2024		$107.53	$9.76	$11.55	$60.85	$168.38	$6.95	$48.37	$86.43
2025		$109.47	$9.94	$11.76	$61.96	$171.43	$7.17	$49.90	$88.65
2026		$111.44	$10.12	$11.97	$63.07	$174.51	$7.51	$52.27	$91.72
2027		$113.56	$10.31	$12.20	$64.28	$177.84	$7.81	$54.36	$94.56
2028		$115.72	$10.51	$12.43	$65.50	$181.22	$8.04	$55.96	$96.92
2029		$117.92	$10.71	$12.67	$66.76	$184.68	$8.23	$57.28	$99.03
2030		$120.16	$10.91	$12.91	$68.02	$188.18	$8.32	$57.91	$100.45
2031		$122.56	$11.13	$13.17	$69.39	$191.95	$8.44	$58.74	$102.13
2032		$124.89	$11.34	$13.42	$70.71	$195.60	$8.60	$59.86	$104.08
2033		$127.26	$11.56	$13.67	$72.03	$199.29	$8.76	$60.97	$106.02
2034		$129.81	$11.79	$13.94	$73.46	$203.27	$8.94	$62.22	$108.17
2035		$132.28	$12.01	$14.20	$74.83	$207.11	$9.10	$63.34	$110.16

Table 8
Total Cost of Displaceable Resources

Sources, Inputs and Assumptions

Source: (a)(c)(d) Plant Costs - 2011 IRP - Table 6.2 & 6.6
(b) = (a) x 0.0837
(e) = (d) x (8.76 x 50.5%) + (c)
(f) = (b) + (e)
(g) Gas Price Forecast
(h) = 6960 x (g) / 1000
(i) = (f) / (8.76 x 'Capacity Factor') + (h)

CCCT (Wet "F" 2x1) - West Side Options (1500')

CCCT Statistics	MW	Percent	Cap Cost	Fixed
CCCT (Wet "F" 2x1)	539	86.2%	$1,067	$8.69
CCCT Duct Firing (Wet "F" 2x1)	86	13.8%	$538	$0.50
Capacity Weighted	625	100.0%	$994	$7.56

CCCT Statistics	MW	CF	aMW	Percent	Variable	Heat Rate
CCCT (Wet "F" 2x1)	539	56.0%	302	95.6%	$8.78	6,885
CCCT Duct Firing (Wet "F" 2x1)	86	16.0%	14	4.4%	12.17	8,681
Energy Weighted	625	50.5%	316	100.0%	$8.93	6,960
						Rounded

CCCT	Duct Firing	Plant Costs - 2011 IRP - Table 6.2 & 6.6
539	86	MW Plant capacity
$1,067	$538	Plant capacity cost
$8.69	$0.50	Fixed O&M plus on-going capital cost
$8.78	$12.17	Variable O&M and Other Costs
$2.98	$4.85	Variable O&M
$5.80	$7.32	Environmental Adders
6,885	8,681	Heat Rate in btu/kWh
8.37%	8.37%	Payment Factor
56%	16%	Capacity Factor
	50.5%	Energy Weighted Capacity Factor
	88.6%	Capacity Factor - On-peak 50.5% / 57% (percent of hours on-peak)

Company Official Inflation Forecast - Dated December 2011							
2011	2.3%	2017	1.9%	2023	1.8%	2029	1.9%
2012	1.5%	2018	1.9%	2024	1.8%	2030	1.9%
2013	1.8%	2019	1.8%	2025	1.8%	2031	2.0%
2014	1.9%	2020	1.7%	2026	1.8%	2032	1.9%
2015	2.0%	2021	1.8%	2027	1.9%	2033	1.9%
2016	1.9%	2022	1.8%	2028	1.9%	2034	2.0%
						2035	1.9%

Table 9
Gas Price Forecast
$/MMBtu

Year	Average Cost of Gas Average of Opal, Sumas and Stanfield Gas Indexes	Burner tip West Side Gas Fuel Cost
	(a)	(b)
2016	$4.66	$4.89
2017	$4.95	$5.21
2018	$5.38	$5.63
2019	$5.79	$6.03
2020	$5.66	$5.90
2021	$5.98	$6.23
2022	$6.53	$6.79
2023	$6.78	$7.07
2024	$6.66	$6.95
2025	$6.87	$7.17
2026	$7.21	$7.51
2027	$7.49	$7.81
2028	$7.69	$8.04
2029	$7.85	$8.23
2030	$7.92	$8.32
2031	$8.06	$8.44
2032	$8.21	$8.60
2033	$8.37	$8.76
2034	$8.53	$8.94
2035	$8.70	$9.10

Source
Offical Market Price Forecast dated December 2011

Table 10

Example of Fuel Indexed Avoided Costs

$/MWh

Banded Gas Market Index

	Prices Listed in the Tariff				Example using assumed Gas Prices						Compared to Fixed Prices	
	On-Peak	Off-Peak	Gas Market Index		Assumed		Fuel Index		Price Paid to QF			
Year	Capacity Adder	Energy Adder	Floor 90%	Ceiling 110%	Gas Price $/MMBtu	Actual Energy Price	Floor / Ceiling Component	Type of Price	Off-Peak Price	On-Peak Price	Off-Peak Price	On-Peak Price
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
						(e) x 6.960			(b) + (g)	(a) + (i)		
					$2.00	$13.92	$29.19	Floor	$36.09	$63.77		
					$4.00	$27.84	$29.19	Floor	$36.09	$63.77		
2016	$27.68	$6.90	$29.19	$35.67	$5.00	$34.80	$34.80	Actual	$41.70	$69.38	$39.33	$67.01
					$7.00	$48.72	$35.67	Ceiling	$42.57	$70.25		
					$10.00	$69.60	$35.67	Ceiling	$42.57	$70.25		

Gas Market Method

	Prices Listed in the Tariff				Example using assumed Gas Prices						Compared to Fixed Prices	
	On-Peak	Off-Peak	Fuel Index		Assumed		Fuel Index		Price Paid to QF			
Year	Capacity Adder	Energy Adder	Floor 90%	Ceiling 110%	Gas Price $/MMBtu	Actual Energy Price	Floor / Ceiling Component	Type of Price	Off-Peak Price	On-Peak Price	Off-Peak Price	On-Peak Price
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
						(e) x 6.960			(b) + (f)	(a) + (i)		
					$2.00	$13.92			$20.82	$48.50		
					$4.00	$27.84			$34.74	$62.42		
2016	$27.68	$6.90	Not Relevant		$5.00	$34.80	Not Relevant		$41.70	$69.38	$39.33	$67.01
					$7.00	$48.72			$55.62	$83.30		
					$10.00	$69.60			$76.50	$104.18		

Columns

(a) Exhibit 3 Column (g)
(b) Exhibit 3 Column (h)
(c) Exhibit 3 Column (j)
(d) Exhibit 3 Column (k)
(f) 6.960 MWh/MMBtu Heat Rate - Table 8 - CCCT (Wet "F" 2x1) - West Side Options (1500')

Table 11
2011 IRP Wyoming Wind Resource
35% Capacity Factor

Year	Estimated Capital Cost $/kW	Fixed Capital Cost at Real Levelized Rate $/kW-yr	Fixed O&M $/kW-yr	Fixed Costs $/MWh	Tax Credit $/MWh	QF Avoided Cost Prices $/MWh
	(a)	(b)	(c)	(d)	(e)	(f)
2011 IRP Wyoming Wind Resource - 35% Capacity Factor						
2010	$2,239	$191.43	$31.93	$72.85	($20.69)	$52.16
2011		$195.84	$32.66	$74.53	($21.17)	$53.36
2012		$198.78	$33.15	$75.65	($21.49)	$54.16
2013		$202.36	$33.75	$77.01	($21.88)	$55.13
2014		$206.20	$34.39	$78.47	($22.30)	$56.17
2015		$210.32	$35.08	$80.04	($22.75)	$57.29
2016		$214.32	$35.75	$81.56	($23.18)	$58.38
2017		$218.39	$36.43	$83.11	($23.62)	$59.49
2018		$222.54	$37.12	$84.69	($24.07)	$60.62
2019		$226.55	$37.79	$86.22	($24.50)	$61.72
2020		$230.40	$38.43	$87.68	($24.92)	$62.76
2021		$234.55	$39.12	$89.26	($25.37)	$63.89
2022		$238.77	$39.82	$90.86	($25.83)	$65.03
2023		$243.07	$40.54	$92.50	($26.29)	$66.21
2024		$247.45	$41.27	$94.17	($26.76)	$67.41
2025		$251.90	$42.01	$95.86	($27.24)	$68.62
2026		$256.43	$42.77	$97.59	($27.73)	$69.86
2027		$261.30	$43.58	$99.44	($28.26)	$71.18
2028		$266.26	$44.41	$101.33	($28.80)	$72.53
2029		$271.32	$45.25	$103.25	($29.35)	$73.90
2030		$276.48	$46.11	$105.22	($29.91)	$75.31
2031		$282.01	$47.03	$107.32	($30.51)	$76.81
2032		$287.37	$47.92	$109.36	($31.09)	$78.27
2033		$292.83	$48.83	$111.44	($31.68)	$79.76
2034		$298.69	$49.81	$113.67	($32.31)	$81.36
2035		$304.37	$50.76	$115.83	($32.92)	$82.91

Sources, Inputs and Assumptions

Source:	(c)(f)	Plant Costs 2011 IRP (Table 6.3) in $2010
	(a)	Plant capacity cost
	(b)	= (a) x 0.0855
	(d)	= ((b) + (c)) / (8.76 x 35.0%)
	(f)	= (d) + (e)
	(g)	= (f) / $52.16

2011 IRP Wyoming Wind Resource - 35% Capacity Factor	
Wind	**Cost and Input Assumptions**
$2,239	Plant capacity cost
$31.93	Fixed O&M plus on-going capital cost 2011 IRP (Table 6.3) in $2010
(20.69)	Tax Credit $/MWh 2011 IRP (Table 6.3) in $2010
8.55%	Payment Factor
35%	Capacity Factor

Official Inflation Forecast Dated December 2011

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

Table 12
Renewable Proxy Resource Pricing
Based on 2011 IRP Wind Resource Costs
Adjusted to On-Peak / Off-Peak Prices

	Renewable Price	On-Peak / Off-Peak Factors		On-Peak / Off-Peak Prices	
Year	$/MWH	On-Peak	Off-Peak	On-Peak	Off-Peak
	(a)	(b)	(c)	(d)	(e)
				(a) x (b)	(a) x (c)
2018	$60.62	1.1262	0.8401	$68.27	$50.93
2019	$61.72	1.1091	0.8610	$68.45	$53.14
2020	$62.76	1.1078	0.8613	$69.52	$54.06
2021	$63.89	1.0800	0.8986	$69.00	$57.41
2022	$65.03	1.0787	0.9002	$70.15	$58.54
2023	$66.21	1.0777	0.9019	$71.36	$59.72
2024	$67.41	1.0748	0.9045	$72.45	$60.97
2025	$68.62	1.0738	0.9060	$73.68	$62.17
2026	$69.86	1.0728	0.9071	$74.94	$63.37
2027	$71.18	1.0689	0.9124	$76.09	$64.94
2028	$72.53	1.0697	0.9119	$77.58	$66.14
2029	$73.90	1.0662	0.9162	$78.79	$67.71
2030	$75.31	1.0643	0.9178	$80.15	$69.11
2031	$76.81	1.0666	0.9138	$81.92	$70.19
2032	$78.27	1.0634	0.9197	$83.23	$71.98
2033	$79.76	1.0609	0.9225	$84.62	$73.58
2034	$81.36	1.0606	0.9237	$86.28	$75.15
2035	$82.91	1.0586	0.9260	$87.77	$76.77

Columns
(a) Table 11 Column (f)
(b) Ratio Mid-Columbia market On-Peak to annual prices
(c) Ratio Mid-Columbia market Off-Peak to annual prices

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit

PacifiCorp's Response to OneEnergy's Data Request 5.2

UM 1610/PacifiCorp
May 21, 2013
OneEnergy Data Request 5.2

OneEnergy Data Request 5.2

Refer to PacifiCorp 2011 IRP Vol. 1, pp 117, 128-130 (OneEnergy/202, Eddie/1-4):

(a) Please explain the difference between a "conventional bubble" and a "wind generation only bubble" as used in the referenced portion of the 2011 IRP.

(b) Please admit or deny that the $2,239/kW Wyoming wind facility listed in page 117, Table 6.3 is to be located in a wind generation only bubble.

(c) Is the proposed $2,239/kW Wyoming wind facility cited in Ms. Brown's testimony above located in the Aeolus Wind-only bubble? If not, please explain.

(d) Does PacifiCorp's $2,239/kW Total Capital Cost (in Table 6.3) of the Wyoming wind facility include "incremental transmission costs" as that term is used in the IRP?

(e) Is it correct to say that "incremental transmission costs" associated with the Wyoming wind facility are the costs of transmission improvements (including PacifiCorp owned transmission) necessitated by construction of the Wyoming wind facility? If not, please explain.

(f) Did PacifiCorp calculate the incremental transmission costs of the Wyoming wind facility? If yes, please provide work papers showing the calculation.

Response to OneEnergy Data Request 5.2

(a) There is no difference between a conventional bubble and a wind-generation-only bubble in terms of the functions in the modeling of Company's system load, resources, and transmission constraints. As indicated in the referenced text of the Company's 2011 Integrated Resource Plan (IRP), the wind-generation-only bubbles were created to appropriately capture the incremental transmission costs that are applicable to the new wind resources.

(b) The Wyoming wind $2,239 / kW capital cost is to be located in the wind only bubble at Aeolus.

(c) Please refer to the Company's response to subpart (b) above.

(d) No.

(e) Yes.

(f) The Company calculated the incremental transmission costs for a Wyoming wind location. Please refer to Confidential Attachment OneEnergy 5.2.

UM 1610/PacifiCorp
May 21, 2013
OneEnergy Data Request 5.2

The confidential attachment is designated as confidential under Protective Order No. 12-461 and may only be disclosed to qualified persons as defined in that order.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit

PacifiCorp's Response to OneEnergy's Data Request 5.3

UM 1610/PacifiCorp
May 21, 2013
OneEnergy Data Request 5.3

OneEnergy Data Request 5.3

Refer to PacifiCorp 2011 IRP Vol. 1, p. 128, which states:

> Incremental transmission costs are expressed as dollars-per-kW values that are applied to costs of wind resources added in wind-generation-only bubbles.

A footnote after that sentence explains, further, that

> Incremental transmission costs also could have been added directly to the wind capital costs.

(a) Explain why PacifiCorp elected not to include incremental transmission costs in Total Capital Costs in Table 6.3.

(b) What would the Total Capital Cost of the Wyoming wind facility be if PacifiCorp included incremental transmission costs? Please provide work papers showing the calculation.

Response to OneEnergy Data Request 5.3

(a) The incremental transmission costs are not considered the cost of a supply side resource such as wind, but are categorized as transmission costs.

(b) The Company has not performed the requested calculation.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit

PacifiCorp's Response to OneEnergy's Data Request 5.4

UM 1610/PacifiCorp
May 21, 2013
OneEnergy Data Request 5.4

OneEnergy Data Request 5.4

Refer to PacifiCorp 2011 IRP Vol. 1. P. 129 which states:

> In the case of east-side wind resources, the only resource location-dependent transmission cost was $71/kW assigned to Wyoming resources based on an estimated incremental expansion of at least 1,500 MW.

(a) Explain how the $71/kW transmission cost was "assigned to Wyoming resources."

(b) Is the $71/kW transmission cost included in the $2,239 Total Capital Cost of the Wyoming Wind resource listed in Table 6.3 of the PacifiCorp 2011 IRP?

(c) Is the $71/kW transmission cost included in the $3,147 Total Capital Cost of the Wyoming Wind resources listed in Table 6.10 of the PacifiCorp 2011 IRP?

(d) Is PacifiCorp saying that, if it built 1,500 MW of its Wyoming wind resource, the incremental transmission cost would be $71/kW? If not, please explain what it is saying.

(e) If PacifiCorp built only 500 MW of its Wyoming wind resource, would the resulting incremental transmission cost be higher, lower, or the same as if it built 1,500 MW of Wyoming wind resource? Please explain your answer.

(f) Please provide work papers showing how the $71/kW was calculated.

Response to OneEnergy Data Request 5.4

(a) The $71/kW transmission costs were assigned as the costs to transfer wind generation from the wind-generation-only bubble, where all potential wind resources are located, to the Company's system.

(b) No. Please refer to the Company's response to OneEnergy Data Request 5.2 subpart (d).

(c) No.

(d) Yes.

(e) The resulting incremental transmission cost would be unchanged. Increasing the transfer capability of the main grid transmission system is made in stepped increments when new facilities are added due to the size and scope of the system. As such, PacifiCorp transmission facilities in Wyoming have been sized to achieve specific transfer capability levels depending on the location of the transmission facility.

(f) Please refer to the Company's response to OneEnergy Data Request 5.2; specifically Confidential Attachment OneEnergy 5.2.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit

PacifiCorp's Response to OneEnergy's Data Request 5.6

UM 1610/PacifiCorp
May 21, 2013
OneEnergy Data Request 5.6

OneEnergy Data Request 5.6

Refer to PacifiCorp IRP Vol. 1. P. 129 which states that:

> No incremental transmission costs are associated with conventional bubbles, other than wheeling charges where applicable. Transmission interconnection costs—direct and network upgrade costs for connecting a wind facility to PacifiCorp's transmission system (230 kV step-up) are included in the wind capital costs.

(a) Please admit or deny that, in its 2011 IRP, PacifiCorp included the cost of transmission network upgrades in the wind capital costs of wind resources located in a conventional bubble, and excluded the cost of transmission network upgrades in the wind capital costs of wind resources located in a wind generation only bubble.
(b) Does the total capital cost of a 2011 IRP wind resource located in a conventional bubble include direct and network upgrade transmission interconnection costs?
(c) Does the total capital cost of a 2011 IRP wind resource located in a wind generation only bubble include direct and network upgrade transmission interconnection costs?

Response to OneEnergy Data Request 5.6

(a) The Company did not include incremental transmission costs or transmission system upgrades in the capital costs of potential wind resources located in any bubbles. Please refer to the Company's response to OneEnergy Data Request 5.7.

(b) The total capital cost of a 2011 IRP wind resource includes transmission interconnection costs, i.e. the costs necessary to connect a project to a nearby transmission line or substation. Please refer to the Company's response to OneEnergy Data Request 5.7.

(c) The total capital cost of a 2011 IRP wind resource includes transmission interconnection costs, i.e. the costs necessary to connect a project to a nearby transmission line or substation. Please refer to the Company's response to OneEnergy Data Request 5.7.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit

PacifiCorp's Response to OneEnergy's Data Request 5.7

UM 1610/PacifiCorp
May 21, 2013
OneEnergy Data Request 5.7

OneEnergy Data Request 5.7

Please fill in the chart, below (for example, if the Wy Wind adjusted construction cost included $71/kW of incremental transmission costs, enter "yes" under the fourth column and $71 under the fifth column in the row titled "incremental transmission costs"):

	$2,239/kW Wy Wind Facility in IRP Table 6.3		$3,147/kW Wy Wind adjusted construction cost in IRP Table 6.10	
Cost Item:	**Included?**	**Cost ($/kW)**	**Included?**	**Cost ($/kW)**
Incremental transmission costs				
Interconnection Costs				
Transmission System upgrades				

Response to OneEnergy Data Request 5.7

	$2,239/kW Wyoming Wind Facility in 2011 IRP Table 6.3		$3,147/kW Wyoming Wind adjusted construction cost in 2011 IRP Table 6.10	
Cost Item:	**Included?**	**Cost ($/kW)**	**Included?**	**Cost ($/kW)**
Incremental transmission costs	No	-	No	-
Interconnection Costs	Yes	The wind capital costs represented an average of several completed wind projects in which the interconnection costs were part of the total project costs and the interconnection costs were not specifically identified	Yes	The wind capital costs represented an average of several completed wind projects in which the interconnection costs were part of the total project costs and the interconnection costs were not specifically identified
Transmission System upgrades	No	-	No	-

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit

PacifiCorp's Response to OneEnergy's Data Request 5.9

UM 1610/PacifiCorp
May 21, 2013
OneEnergy Data Request 5.9

OneEnergy Data Request 5.9

Please refer to PacifiCorp's reply testimony PAC/300, Dickman/33, which reads:

> The cost of reserves necessary to integrate solar could be equal to or greater than wind integration for the following reasons: (1) Solar resources have the potential to exhibit sharp swings in output as a result of rapidly changing cloud cover, where wind output changes more gradually. (2) Sharp changes in solar output can occur nearly instantaneously, resulting in strains on the system that may require additional reserves relative to wind. (3) Because all of the variability of solar occurs during the day, a greater portion the reserves necessary to integrate solar must be held during on-peak hours, when the opportunity cost of holding reserves is highest. (4) Correlation between load and solar generation has the potential to increase the ramping reserve requirements because of the timing of solar output relative to system load. These four factors cause the Company to believe that, despite the differences in wind and solar generation, the wind integration costs serve as a fair proxy for the cost to integrate solar resources on PacifiCorp's system.

(a) Please provide any studies and/or documentation supporting these four factors which Mr. Dickman relied on in forming the opinion above.
(b) What is the total nameplate capacity of solar PV interconnected to PacifiCorp's Oregon system?

Response to OneEnergy Data Request 5.9

(a) The four factors are general characteristics of solar output. The Company did not perform any studies to quantify the impact of these factors on integration costs.

(b) The only utility scale solar resource on the Company's system is the 2 MW Black Cap Solar project in Lake County, Oregon.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit

PacifiCorp's Response to OneEnergy's Data Request 5.11

UM 1610/PacifiCorp
May 21, 2013
OneEnergy Data Request 5.11

OneEnergy Data Request 5.11

Refer to Exhibit PAC/301, Dickman/1 table comparing avoided costs. Please provide an updated version of the table with the following additional columns using price forecasts of the same vintage.

(a) Market Blend on-peak
(b) Market Blend off-peak
(c) Mid-C on-peak
(d) Mid-C off-peak
(e) COB on-peak
(f) COB off-peak
(g) COB all hours

Response to OneEnergy Data Request 5.11

Please refer to Attachment OneEnergy 5.11.

OR UM 1610
OneEnergy 5.11

Comparison of Avoided Costs Using Mid C vs. Blended Market
$/MWh

Year	Total Avoided Costs (1)								
	Market Blend Filing Filed March 21, 2012			Mid-C Market Filing Filed March 2, 2012			COB Market Filing		
	Flat	On-Peak (a)	Off-Peak	Flat	On-Peak (b)	Off-Peak	Flat	On-Peak (c)	Off-Peak
2012	$27.56	$30.87	$23.18	$26.40	$29.41	$22.57	$29.34	$32.69	$24.89
2013	$32.46	$37.19	$26.19	$31.99	$36.13	$26.69	$35.28	$39.88	$29.19
2014	$35.58	$41.27	$28.04	$35.08	$39.31	$29.69	$39.32	$44.56	$32.38
2015	$37.89	$43.92	$29.90	$37.67	$42.56	$31.44	$41.93	$47.81	$34.13
2016	$50.86	$60.42	$36.85	$50.86	$60.42	$36.85	$50.86	$60.42	$36.85
2017	$53.41	$63.16	$39.14	$53.41	$63.16	$39.14	$53.41	$63.16	$39.14
2018	$56.66	$66.60	$42.12	$56.66	$66.60	$42.12	$56.66	$66.60	$42.12
2019	$59.77	$69.88	$44.96	$59.77	$69.88	$44.96	$59.77	$69.88	$44.96
2020	$59.15	$69.43	$44.09	$59.15	$69.43	$44.09	$59.15	$69.43	$44.09
2021	$61.78	$72.25	$46.45	$61.78	$72.25	$46.45	$61.78	$72.25	$46.45
2022	$66.01	$76.67	$50.41	$66.01	$76.67	$50.41	$66.01	$76.67	$50.41
2023	$68.31	$79.16	$52.42	$68.31	$79.16	$52.42	$68.31	$79.16	$52.42
2024	$67.80	$78.85	$51.63	$67.80	$78.85	$51.63	$67.80	$78.85	$51.63
2025	$69.68	$80.93	$53.22	$69.68	$80.93	$53.22	$69.68	$80.93	$53.22
2026	$72.41	$83.85	$55.65	$72.41	$83.85	$55.65	$72.41	$83.85	$55.65
2027	$74.89	$86.55	$57.81	$74.89	$86.55	$57.81	$74.89	$86.55	$57.81
2028	$76.88	$88.77	$59.48	$76.88	$88.77	$59.48	$76.88	$88.77	$59.48
2029	$78.59	$90.70	$60.86	$78.59	$90.70	$60.86	$78.59	$90.70	$60.86
2030	$79.63	$91.97	$61.56	$79.63	$91.97	$61.56	$79.63	$91.97	$61.56
2031	$80.89	$93.48	$62.46	$80.89	$93.48	$62.46	$80.89	$93.48	$62.46
20 Year (2012 - 2031) levelized Price at 7.17% Discount Rate									
$/MWh	$54.28	$63.10	$41.58	$54.08	$62.63	$41.81	$55.26	$64.03	$42.63

Note: (1) Total Avoided Costs with Capacity Costs included at 85% Capacity Factor

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit

PacifiCorp's Response to OneEnergy's Data Request 5.12

UM 1610/PacifiCorp
May 21, 2013
OneEnergy Data Request 5.12

OneEnergy Data Request 5.12

Refer to Table 9 of PacifiCorp's Schedule 37 avoided cost calculation workpapers, which provides a gas price forecast averaged for Opal, Sumas, and Stanfield hubs and a burner tip west side gas fuel cost. Please provide a table of the same forecasts using *only* price forecasts for Stanfield and corresponding burner tip costs. Please use forecasts of the same vintage as those used in PacifiCorp's current Schedule 37.

Response to OneEnergy Data Request 5.12

Please refer to Attachment OneEnergy 5.12.

OR UM 1610
OneEnergy 5.12

Attachment OneEnergy 5.12

Gas Price Forecast
$/MMBtu

Year	Stanfield Only Gas Indexes	Burner tip Stanfield Only Fuel Cost
	(a)	(b)
2016	$4.67	$4.97
2017	$4.95	$5.26
2018	$5.38	$5.73
2019	$5.82	$6.19
2020	$5.71	$6.07
2021	$6.04	$6.42
2022	$6.58	$7.00
2023	$6.83	$7.26
2024	$6.73	$7.16
2025	$6.94	$7.38
2026	$7.27	$7.73
2027	$7.56	$8.04
2028	$7.79	$8.28
2029	$7.96	$8.47
2030	$8.06	$8.57
2031	$8.23	$8.75
2032	$8.39	$8.92
2033	$8.55	$9.09
2034	$8.72	$9.27
2035	$8.89	$9.45

Source
Offical Market Price Forecast dated December 2011

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit

PacifiCorp's Response to OneEnergy's Data Request 5.13

UM 1610/PacifiCorp
May 21, 2013
OneEnergy Data Request 5.13

OneEnergy Data Request 5.13

Please refer to PacifiCorp's reply testimony PAC/400, Griswold/5-6, which reads

> Based on the Company's historical QF agreements, providing a levelized pricing option to those at or under a 3 MW threshold would have meant offering levelized prices to half of the Oregon QF projects with which the Company has executed PPAs. Regardless of the size of the QF project, the Company and its customers are still accepting credit risk associated with the risk of default by the QF project in the early years.

Regarding the aforementioned executed "historical QF agreements" at or under 3 MW in Oregon, please state:

(a) the total number of such QF PPAs, and the sum of their nameplate capacities;
(b) the total number of such QF PPAs under which PacifiCorp provided formal notice of default and/or termination to the QF and the sum of their nameplate capacities; and
(c) the total number of such QF PPAs under which PacifiCorp provided formal notice of default and/or termination to the QF *after* the QF commenced commercial deliveries to PacifiCorp under the agreement, and the sum of their nameplate capacities.

Response to OneEnergy Data Request 5.13

(a) Historically, the Company has executed 48 qualifying facility (QF) power purchase agreements (PPAs) that had nameplate capacities under or equal to 3.0 megawatts (MW). Total nameplate capacity for those 48 QFs is 23.7 MW. Of the 48 QFs, 25 are currently operating or in development. Nameplate capacity for this subset is 20.9 MW.

(b) Historically, the Company has terminated per contract terms a total of three QF PPAs that had nameplate capacities under or equal to 3.0 MW. Total nameplate capacity for those three QFs is 1 MW. Of the 25 active QFs, two QFs are in default for not meeting the scheduled commercial operation date (COD), but have not been terminated because the Oregon Public Utilities Commission does not allow termination during the sufficiency period of their contract. Nameplate capacity for this subset is 3.3 MW

(c) Historically, the Company has terminated after COD per the contract terms a total of four QF PPAs that had nameplate capacities under or equal to 3.0 MW. Total nameplate capacity for those four QFs is 2.0 MW.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit

PacifiCorp's Response to OneEnergy's Data Request 5.8

UM 1610/PacifiCorp
May 21, 2013
OneEnergy Data Request 5.8

OneEnergy Data Request 5.8

For the $2,239/kW Wyoming wind facility PacifiCorp proposes for the renewable proxy:

(a) What state sales tax (%) did PacifiCorp include in the $2,239/kW price?
(b) What state property tax (%) did PacifiCorp include in the $2,239/kW price?
(c) What state excise tax ($/MWh) did PacifiCorp include in the $2,239/kW price?
(d) If PacifiCorp builds the Wyoming wind facility, will that facility be assessed a state income tax of 5.4%? If not, please explain.
(e) If PacifiCorp builds the Wyoming wind facility, will that facility be assessed a state property tax of 0.7%? If not, please explain.
(f) If PacifiCorp builds the Wyoming wind facility, will that facility be assessed a state excise tax of $1/MWh? If not, please explain.

Response to OneEnergy Data Request 5.8

(a) The state sales tax (percent) was not specifically identified in the $2,239/kW price. At the time the costs of resources for the 2011 supply side resource table were developed, wind projects located in Wyoming received a waiver of state sales tax.

(b) The state property tax (percent) was not specifically identified in the $2,239/kW price. Property taxes are captured in the capital recovery factor, used to levelize capital cost revenue requirement in IRP modeling. The property tax assumed in the calculation of the capital recovery factor is 1.1 percent.

(c) None.

(d) The generation of income creates total Company state income tax at the combined state income tax rate of 4.54 percent which is then allocated to Wyoming under the 2010 Protocol allocation methodology.

(e) Property tax rates vary by location based upon the cost of providing governmental services to property owners. All other things being equal, property tax rates in rural areas tend to be lower than tax rates for more densely populated areas. For the most recent tax year, PacifiCorp's composite Wyoming wide property tax rate was approximately 0.75 percent. This rate is properly applied to assessed value amounts rather than property cost amounts.

(f) Wyo. Stat. § 39-22 imposes an excise tax of $1.00/MWh upon the privilege of producing electricity from wind resources in Wyoming. Electricity produced from a wind turbine is not subject to the tax until the date three years after the turbine first produced electricity for sale.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that, on the 30th day of May 2013, I served a true and correct copy of the foregoing *Hearing Exhibits OneEnergy/400-411* in OPUC Docket No. UM 1610 on the following named persons/entities by electronic mail.

DATED this 30th day of May 2013.

LOVINGER KAUFMANN LLP

Dana Hurley
Office Manager

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