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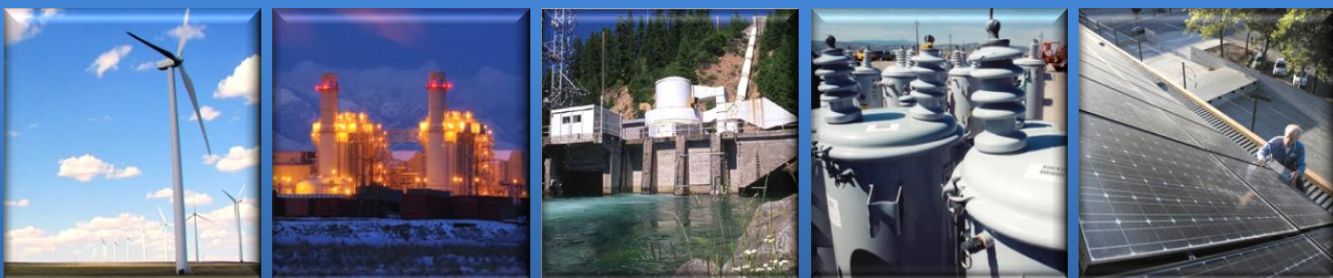
2011
Integrated Resource Plan
Addendum



Let's turn the answers on.

June 27, 2011

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Cover Photos (Left to Right):
Wind: *McFadden Ridge I*
Thermal-Gas: *Lake Side Power Plant*
Hydroelectric: *Lemolo 1 on North Umpqua River*
Transmission: *Distribution Transformers*
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ADDENDUM INTRODUCTION

This addendum to the 2011 IRP includes the results of additional studies and analysis that could not be completed in time to include in the original filed IRP document. These studies and analysis consist of the following:

- Development of stochastic cost results for 16 Energy Gateway scenarios documented in Chapter 4 of the 2011 IRP.
- Stochastic production cost simulation of revised full Energy Gateway and minimal Energy Gateway portfolios; the revised portfolios account for transmission operational constraints not captured with the *System Optimizer* capacity expansion model, as well as an alternate strategy for representing out-year generation resources.
- An energy efficiency (Class 2 demand-side management) avoided cost study, referred to as the DSM decrement analysis.
- An evaluation of wind capital cost and capacity factor recommendations and associated supporting data provided by Interwest Energy Alliance.

CHAPTER 1 – STOCHASTIC RESULTS FOR ENERGY GATEWAY SCENARIOS

Introduction

PacifiCorp conducted stochastic Monte Carlo production cost simulation of the portfolios and associated transmission assumptions for the "Green Resource Future" Energy Gateway expansion scenarios described in Chapter 4 of the 2011 IRP. (Refer to the "Transmission Scenario Analysis" section, beginning on page 66, for background information on these scenarios and associated resource modeling assumptions.) As noted in the IRP, PacifiCorp assumes that state and federal energy policies will continue to emphasize strong support for renewables development. Hence, the Company focused on the "Green Resource Future" set of scenarios for stochastic modeling. The Company also concluded that the full Energy Gateway configuration provides a number of strategic benefits. These benefits include insurance for regulatory uncertainty and risk mitigation associated with increased resource diversity and operational flexibility.

These production cost simulations, performed with the Planning and Risk (PaR) model, are consistent with the stochastic simulations conducted for the core portfolio cases[1], utilizing two carbon dioxide (CO_2) tax scenarios: \$0/ton and \$19/ton (or "medium" scenario).[2] Figures 1 through 4 are maps of the four Energy Gateway expansion scenarios.

[1] Refer to the "Monte Carlo Production Cost Simulation" section of Chapter 7, beginning on page 182, for background on stochastic production cost modeling conducted for the IRP.
[2] Refer to page 159 of the 2011 IRP for definition of the CO_2 tax scenarios.

Figure 1 – Energy Gateway Scenario 1 ("Gateway-Limited")

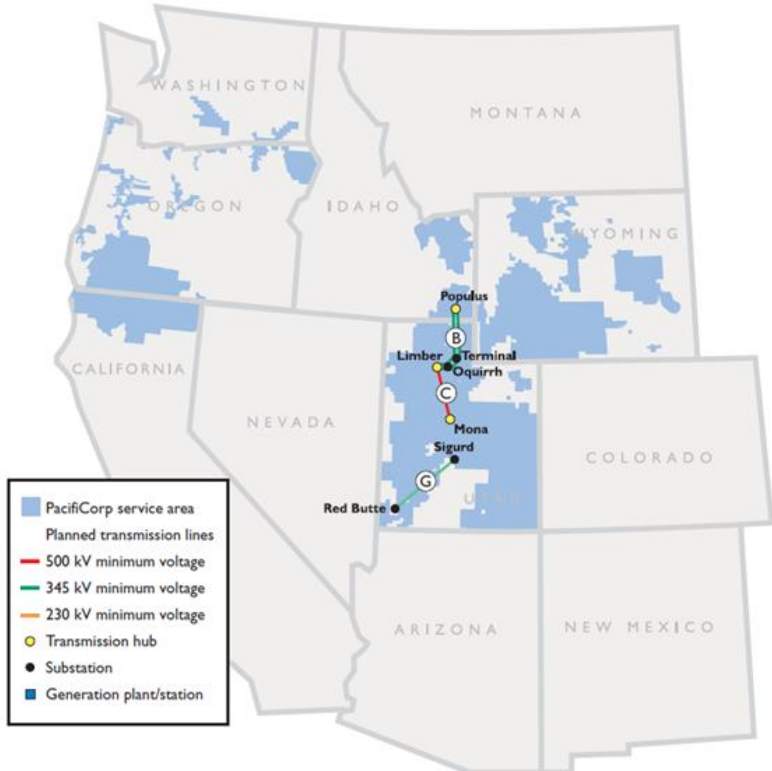


Figure 2 – Energy Gateway Scenario 2

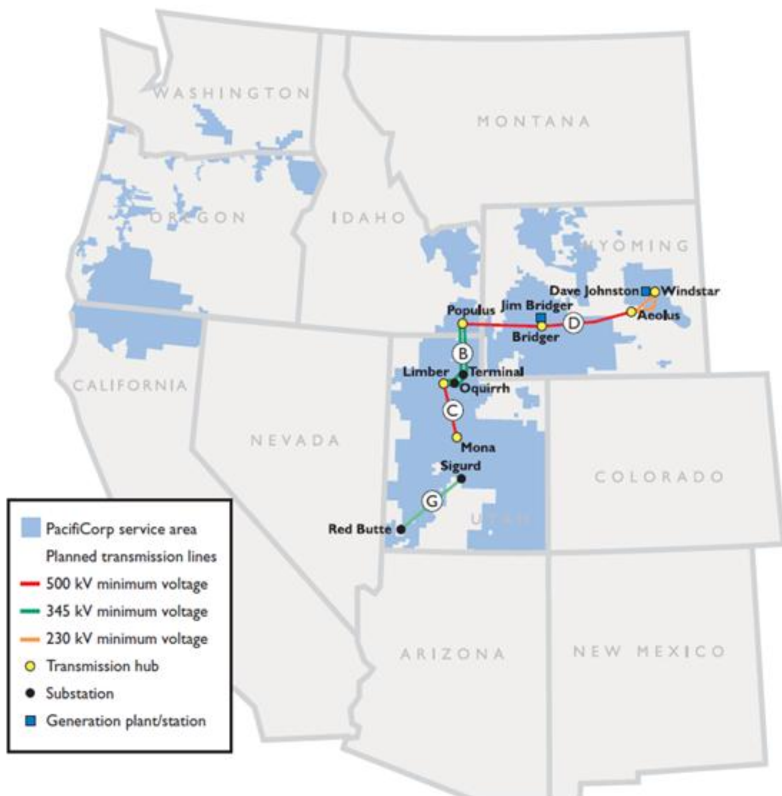


Figure 3 – Energy Gateway Scenario 3

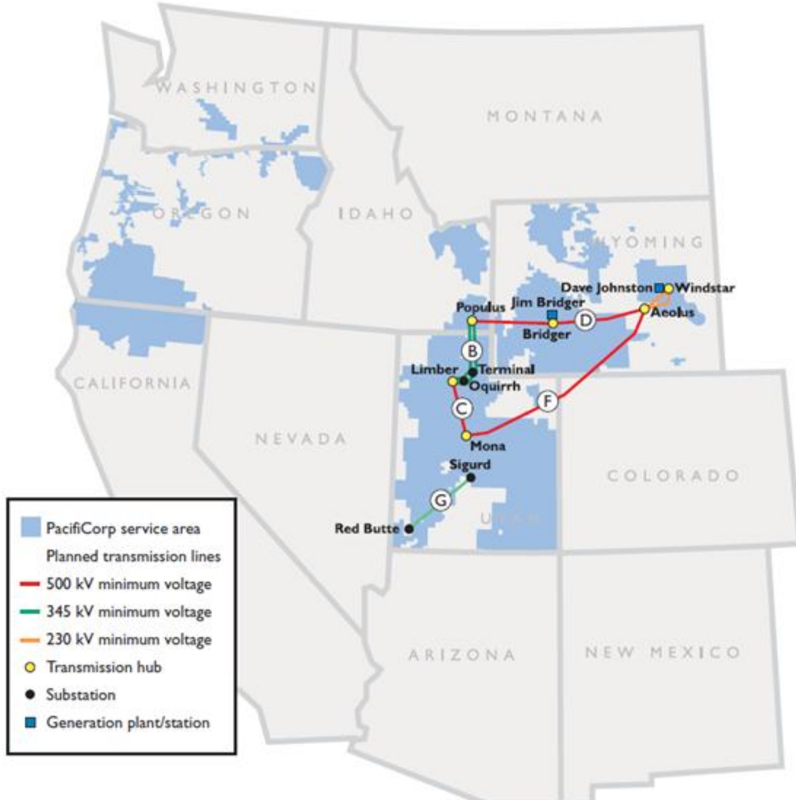
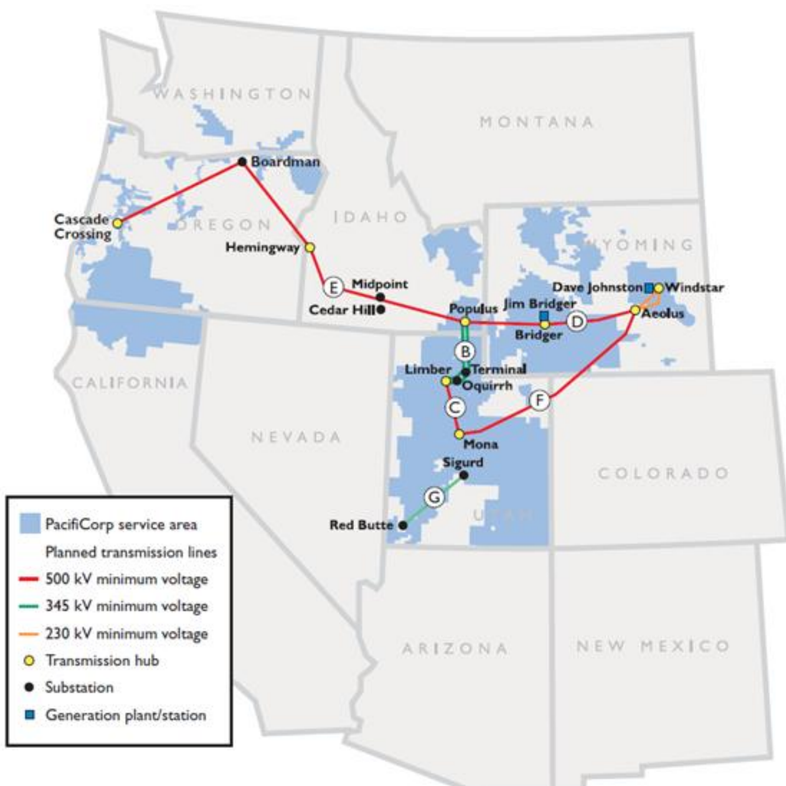


Figure 4 – Energy Gateway Scenario 4 (“Full Gateway”)



Stochastic Production Cost Modeling Results

Tables 1 and 2 report the stochastic mean Present Value Revenue Requirement (PVRR) for the two CO_2 tax scenarios along with the PVRR cost component details.

Table 1 – Stochastic Mean PVRR Cost Comparison for Energy Gateway Scenarios, No CO_2 Tax ("Green Resource Future")

	Medium Natural Gas Price Forecast				High Natural Gas Price Forecast			
Cost Component (Million $)	Scenario 1	Scenario 2	Scenario 3	Scenario 4*	Scenario 1	Scenario 2	Scenario 3	Scenario 4*
Variable Costs								
Fuel & O&M	15,295	15,235	15,232	15,184	15,327	15,211	15,288	15,181
Emission Cost	2	2	2	2	2	2	2	2
FOT's & Long Term Contracts	3,857	3,858	3,858	3,858	3,819	3,811	3,800	3,807
Demand Side Management	3,373	3,421	3,421	3,421	4,059	4,137	4,139	4,137
Renewables	699	699	699	699	700	681	681	681
System Balancing Sales	(6,031)	(6,008)	(6,007)	(6,017)	(6,084)	(6,014)	(5,989)	(6,011)
System Balancing Purchases	1,715	1,705	1,705	1,727	1,683	1,673	1,695	1,709
Energy Not Served	44	48	48	47	42	50	50	49
Dump Power	(133)	(131)	(131)	(132)	(137)	(140)	(140)	(141)
Reserve Deficiency	0	0	0	0	0	0	0	0
Total Variable Costs	$18,821	$18,829	$18,827	$18,789	$19,411	$19,412	$19,525	$19,412
Capital and Fixed Costs	$12,067	$11,131	$11,159	$11,201	$12,128	$11,362	$11,111	$11,336
Total PVRR	**$30,888**	**$29,960**	**$29,986**	**$29,990**	**$31,540**	**$30,774**	**$30,636**	**$30,748**

* Scenario 4 corresponds to Scenario 7 in Table 4.2, page 78, of the 2011 IRP.

Table 2 – Stochastic Mean PVRR Cost Comparison for Energy Gateway Scenarios, Medium CO_2 Tax Scenario ("Green Resource Future")

	Medium Natural Gas Price Forecast				High Natural Gas Price Forecast			
Cost Component (Million $)	Scenario 1	Scenario 2	Scenario 3	Scenario 4*	Scenario 1	Scenario 2	Scenario 3	Scenario 4*
Variable Costs								
Fuel & O&M	15,231	15,165	15,155	15,048	15,300	15,181	15,263	15,087
Emission Cost	7,409	7,332	7,335	7,230	7,331	7,190	7,238	7,096
FOT's & Long Term Contracts	4,063	4,064	4,064	4,064	4,018	4,008	3,994	4,003
Demand Side Management	3,373	3,421	3,421	3,421	4,059	4,137	4,139	4,137
Renewables	693	693	693	693	694	681	681	681
System Balancing Sales	(6,458)	(6,413)	(6,413)	(6,387)	(6,528)	(6,422)	(6,399)	(6,387)
System Balancing Purchases	2,631	2,646	2,647	2,740	2,583	2,597	2,623	2,710
Energy Not Served	44	48	48	47	42	50	49	48
Dump Power	(127)	(126)	(126)	(128)	(131)	(135)	(135)	(137)
Reserve Deficiency	0	0	0	0	0	0	0	0
Total Variable Costs	$26,858	$26,830	$26,826	$26,729	$27,368	$27,287	$27,452	$27,237
Capital and Fixed Costs	$12,067	$11,131	$11,159	$11,201	$12,128	$11,362	$11,111	$11,336
Total PVRR	**$38,925**	**$37,961**	**$37,985**	**$37,930**	**$39,496**	**$38,650**	**$38,563**	**$38,573**

* Scenario 4 corresponds to Scenario 7 in Table 4.2, page 78, of the 2011 IRP.

Conclusion

The stochastic modeling results indicate that the full Energy Gateway configuration is cost-effective when compared to the Limited Gateway configuration in all CO_2 tax/natural gas price scenarios and outperforms Energy Gateway Scenarios 2 and 3 with medium natural gas prices and medium CO_2 prices. Consistent with the deterministic modeling results using the System Optimizer model, the stochastic PVRR range for Energy Gateway expansion scenarios 2 through 4 is narrow, suggesting that economics does not drive a clear selection of the alternatives. As noted in the 2011 IRP, the Company continues to conclude that proceeding with the full Energy Gateway expansion scenario is the most prudent strategy.

Supplemental Limited Energy Gateway Scenario Analysis

Introduction

The 2011 IRP contemplated seven different scenarios of the Company's Energy Gateway transmission expansion program. The "base case" (Scenario 1) is a minimum-build transmission plan that, while part of the overall Energy Gateway strategy, needs to be constructed regardless of other Energy Gateway options due to specific load and reliability requirements. This group of projects—referred to as "Gateway-Limited" for the purpose of this IRP addendum—includes Populus to Terminal, Mona to Oquirrh and Sigurd to Red Butte. (Refer to Chapter 10 of the 2011 IRP[3] for detailed information on each of the planned Energy Gateway segments). To analyze these transmission planning scenarios, PacifiCorp used its *System Optimizer* model to select optimal resource portfolios constrained by the transmission topology defined for each Energy Gateway scenario. Both the System Optimizer results reported in the 2011 IRP and the stochastic production cost simulations described in the previous section indicate that the full Energy Gateway strategy has a lower PVRR than the Gateway-Limited strategy under a range of alternative natural gas and CO_2 price assumptions. These two Energy Gateway scenarios are shown in Figures 1 and 4 above.

As an extension of this Energy Gateway scenario analysis, the Company wanted to investigate the extent to which operational limitations of the transmission system under the Gateway-Limited scenario constrain the location of thermal resources as determined by System Optimizer. At issue is whether System Optimizer is adequately accounting for the need (and associated cost) to site thermal resources at alternative locations given such operational constraints. A particular focus is on *growth resources* that the model uses to balance capacity in the outer years of the simulations. Growth resources, which are assigned forward market prices, serve as proxies for unspecified electricity supply options. They are also made available within load bubbles as opposed to acquiring them from market hubs.[4] Use of growth resources circumvents transmission constraints as a limiting factor for adding future resources, and thus may not be a suitable out-year resource modeling strategy when evaluating transmission expansion scenarios.

For this supplemental Energy Gateway scenario analysis, the Company's goal was thus to determine the resource selection and cost impact of applying locational resource constraints

[3] PacifiCorp IRP documents are available at www.pacificorp.com/es/irp.html
[4] Growth resources are described on page 179 of the 2011 IRP.

based on transmission capacity limits, as well as removing growth resources as future resource options. To this end, PacifiCorp developed revised Full Gateway and Gateway-Limited portfolios reflecting application of these resource modeling changes, and then simulated them with the PaR production cost model to provide a PVRR cost comparison. Subsequent sections provide more details on the revised portfolio development approach and the results of the scenario analysis.

Study Approach Details

As noted above, the study approach consisted of developing Gateway-Limited and Full Gateway portfolios using System Optimizer, and then simulating both portfolios using the Planning and Risk production cost model. The main modeling assumptions for the study are as follows:

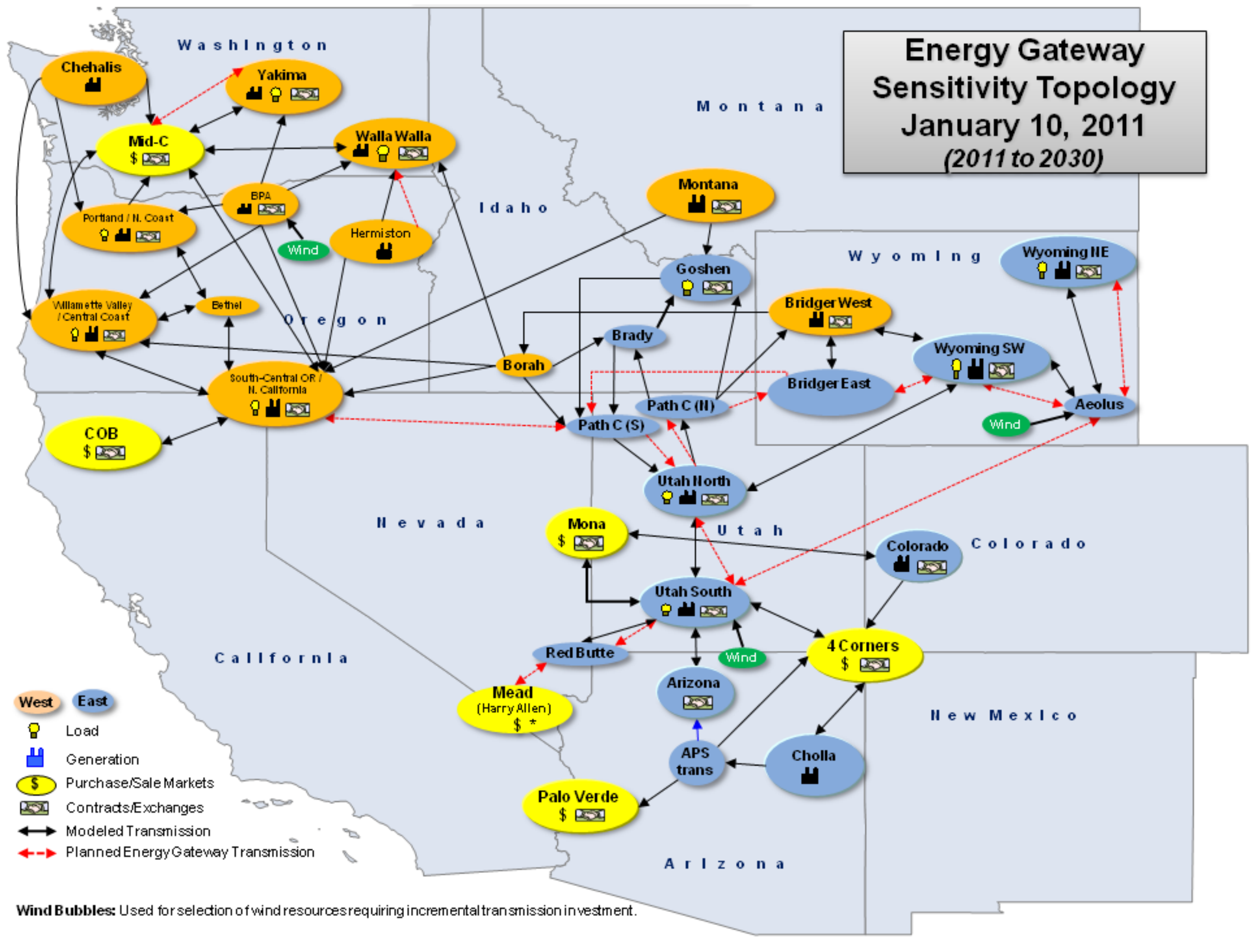
- The expected load, natural gas price, wholesale electricity price, CO_2 price forecasts from the 2011 IRP (described on pages 175-176), developed in September 2010, were used.
- With the exception of growth resources (previously available beginning in 2021) and geothermal[5], all resource options specified for the 2011 IRP were available for System Optimizer selection. Gas-fired combined-cycle combustion turbine plants acquired after 2019 are represented by two technology options: Mitsubishi G/General Electric H class 1x1[6], and General Electric F class 2x1, both with duct firing. (System Optimizer is allowed to select a fractional amount of duct-firing capacity up to the specified megawatt limits.) All east-side CCCTs beyond 2014 are assumed to be dry-cooled.
- Consistent with the Green Resource Future outlined in Chapter 4 of the 2011 IRP ("Transmission Planning"), portfolios are required to meet minimum annual renewable generation requirements based on the Waxman-Markey proposed targets (6 percent by 2012, 9.5 percent by 2014, 13 percent by 2016, 16.5% by 2018, and 20% by 2020). The model is allowed to select an optimal amount of wind resources subject to the minimum renewable generation requirements.
- System Optimizer was allowed to select a variable amount of market purchases (front office transaction proxy resources) up to the annual market hub limits.
- Consistent with the original minimum-build Energy Gateway scenario, incremental wind resources in Wyoming were excluded as model options in the Gateway-Limited scenario.
- The base transmission topology for the 2011 IRP was used, which is shown in Figure 5.

To account for operational transmission constraints under the Gateway-Limited scenario, PacifiCorp first ran System Optimizer based on the above assumptions to create a base Gateway-Limited portfolio for inspection by the Transmission Department. Based on this inspection, PacifiCorp conducted a final System Optimizer run that incorporated the following resource changes needed to account for a 700 MW incremental capacity transfer limit from the "Utah South" to "Utah North" topology bubbles once the Mona-Oquirrh transmission project is in place:

[5] Geothermal resources are excluded as resource options due to recovery risk for resource development costs, a procurement issue identified in the 2011 IRP. Geothermal projects will nevertheless be included as eligible resources in future Requests for Proposals.
[6] The G and H class CCCTs are assumed to have the same capacity and other attributes, and are considered interchangeable.

- The model was constrained to locate 300 MW of Utah wind ("Utah South" bubble) to the west side of the system (Oregon and Washington).
- The 2019 CCCT resource originally selected by the model at Currant Creek ("Utah South" Bubble) was manually moved to the "Utah North" bubble.
- The 2025 CCCT resource originally selected by the model for the "Utah North" bubble was moved to the Borah bubble located in Idaho.

Figure 5 – Transmission System Model Topology



PacifiCorp simulated the Full Gateway and final Gateway-Limited portfolios using the PaR model. Transmission investment costs were incorporated in the PVRRs, consistent with the approach used for the original minimal-build and full Energy Gateway scenarios.

Study Results

Tables 4 and 5 show the revised Full Gateway and Gateway-Limited portfolio resources respectively after running System Optimizer with the resource modifications described above. Table 6 provides the resource differences between the two portfolios. The major resource changes consist of a location shift of a simple-cycle combustion turbine plant and the Wyoming wind to the west.

Table 3 – Resource Portfolio, Revised Full Energy Gateway Scenario (“Green Resource Future”)

		Capacity (MW)																				Resource Totals *	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																							
	CCCT F 2x1: Utah North, Utah South	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
	CCCT G 1x1: Goshen, Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	388	-	388	-	-	-	-	776
	CCCT H 1x1, Utah South	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
	IC Aero Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	93	-	-	93
	SCCT Aero, Utah South	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	118	-	118
	Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
	Wind, Goshen, 29% Cap Factor	-	-	-	-	-	-	70	-	-	-	-	-	-	-	-	-	-	-	-	-	70	70
	Wind, Utah, 29% Cap Factor	-	-	-	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, Wyoming, 35% Cap Factor	-	-	-	-	-	-	-	200	200	200	15	73	38	48	20	99	49	78	40	187	600	1,247
	Total Wind	-	-	-	-	-	-	170	200	200	200	15	73	38	48	20	99	49	78	40	187	770	1,418
	CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
	DSM, Class 1 Total	6	69	3	20	86	-	-	-	-	-	-	2	-	-	-	10	-	-	-	-	184	196
	DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	40
	DSM, Class 2, Utah	45	48	41	43	44	47	49	50	52	57	60	64	64	67	86	92	64	67	70	74	477	1,186
	DSM, Class 2, Wyoming	3	4	4	5	5	6	6	7	7	8	9	10	11	14	15	19	20	24	29	31	55	236
	DSM, Class 2 Total	48	53	46	49	51	55	57	59	61	66	71	76	78	84	104	114	86	94	102	108	545	1,462
	Micro Solar - Hot Water Heating	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.37	2.64	24	50
	FOT Mead Q3	-	168	264	264	99	17	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81	41
	FOT Utah Q3	200	200	200	8	243	-	57	200	-	176	-	8	106	145	73	202	-	111	198	200	128	116
	FOT Mona-3 Q3	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
	FOT Mona-4 Q3	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
West																							
	Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
	Wind, Yakima, 29% Cap Factor	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Wind, Walla Walla, 29% Cap Factor	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
	Total Wind	-	-	-	200	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
	Utility Biomass	-	-	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	50	50
	CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
	DSM, Class 1 Total	-	-	62	6	4	-	-	-	-	-	-	-	-	-	-	7	-	-	-	-	72	78
	DSM, Class 2, Walla Walla	4	4	4	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	46	91
	DSM, Class 2, California/Oregon	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	550	1,017
	DSM, Class 2, Yakima	6	6	6	6	6	6	6	7	7	7	8	9	9	9	9	7	6	7	6	7	64	141
	DSM, Class 2 Total	61	62	65	70	72	71	70	63	63	64	65	66	66	67	67	64	55	47	47	47	659	1,250
	OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
	OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
	Micro Solar - Hot Water Heating	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.29	0.97	0.97	16	32
	FOT COB Q3	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	32
	FOT MidColumbia Q3	-	400	400	400	400	400	400	400	375	400	333	400	400	400	400	400	400	400	400	400	358	375
	FOT MidColumbia Q3 - 2	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
	FOT South-Central Oregon/North Cal Q3	-	50	50	50	50	50	50	50	-	50	-	50	50	50	50	50	50	50	50	50	40	43
	Annual Additions, Long Term Resources	136	217	196	983	225	750	308	340	808	389	163	227	191	208	589	303	588	228	290	469		
	Annual Additions, Short Term Resources	350	1,239	1,425	1,172	1,142	767	807	950	675	926	633	758	856	895	823	952	750	861	948	950		
	Total Annual Additions	486	1,456	1,621	2,155	1,367	1,517	1,114	1,290	1,484	1,316	796	986	1,047	1,104	1,412	1,254	1,338	1,089	1,238	1,419		

* Front office transactions (FOT) are not additive. For the 10-Year column, FOT are a 10-year average for 2011-2020, whereas the 20-Year column report a 10-year average for 2021-2030.

Table 4 – Resource Portfolio, Revised Energy Gateway-Limited Scenario ("Green Resource Future")

	Capacity (MW)																				Resource Totals *	
Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10-year	20-year
East																						
CCCT F 2x1: Utah North, Utah South	-	-	-	625	-	597	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,222	1,222
CCCT G 1x1: Goshen, Utah North	-	-	-	-	-	-	-	-	-	-	-	-	-	-	388	-	388	-	-	-	-	776
CCCT H 1x1, Utah South	-	-	-	-	-	-	-	-	475	-	-	-	-	-	-	-	-	-	-	-	475	475
IC Aero, Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	93	-	93
Coal Plant Turbine Upgrades	12.1	18.9	1.8	-	-	18.0	-	-	-	-	2.4	-	-	-	-	-	-	-	-	-	51	53
Wind, Goshen, 29% Cap Factor	-	-	-	-	-	100	100	-	-	-	-	-	-	-	-	-	-	-	-	-	200	200
Wind, Utah, 29% Cap Factor	-	-	-	-	-	-	94	100	100	100	18	88	-	-	-	-	-	-	-	-	394	500
Total Wind	-	-	-	-	-	100	194	100	100	100	18	88	-	-	-	-	-	-	-	-	594	700
CHP - Biomass	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	10	20
DSM, Class 1 Total	6	69	3	20	79	-	-	-	-	-	-	2	-	-	-	17	-	-	-	-	177	196
DSM, Class 2, Goshen	1	1	1	1	1	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	14	40
DSM, Class 2, Utah	45	48	41	43	44	47	49	50	52	57	60	64	64	67	71	92	63	67	70	90	477	1,186
DSM, Class 2, Wyoming	3	4	4	5	5	6	6	7	7	8	9	10	11	14	15	19	20	24	29	31	55	236
DSM, Class 2 Total	48	53	46	49	51	55	57	59	61	66	71	76	78	84	89	114	86	94	102	124	545	1,463
Micro Solar - Hot Water Heating	-	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	2.64	24	50
FOT Mead Q3	-	168	264	264	99	15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	81	40
FOT Utah Q3	200	200	200	8	250	-	52	195	-	171	-	3	101	140	80	202	-	111	189	200	128	115
FOT Mona-3 Q3	-	-	-	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	210	255
FOT Mona-4 Q3	-	-	150	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	15	8
West																						
Coal Plant Turbine Upgrades	-	-	3.7	-	-	-	-	8.3	-	-	-	-	-	-	-	-	-	-	-	-	12	12
IC Aero, South-Central Oregon/Californi	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	102	-	-	102
Wind, Yakima, 29% Cap Factor	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Wind, Oregon, 29% Cap Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	-	-	-	84	-	104
Wind, Washington, 29% Cap Factor	-	-	-	-	-	13	6	100	100	100	-	-	43	57	26	100	58	95	45	100	319	844
Wind, Walla Walla, 29% Cap Factor	-	-	-	100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	100	100
Total Wind	-	-	-	200	-	13	6	100	100	100	-	-	43	57	26	120	58	95	45	184	519	1,148
Utility Biomass	-	-	-	-	-	-	-	-	-	50	-	-	-	-	-	-	-	-	-	-	50	50
CHP - Biomass	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	42	84
DSM, Class 1 Total	-	-	62	6	4	-	-	-	-	-	-	-	-	-	-	7	-	-	-	-	72	78
DSM, Class 2, Walla Walla	4	4	4	5	5	5	5	4	5	5	5	5	5	5	5	5	4	4	4	4	45	91
DSM, Class 2, California/Oregon	51	51	54	59	60	60	59	52	52	52	52	52	52	52	53	52	44	37	37	36	550	1,018
DSM, Class 2, Yakima	6	6	6	6	6	6	6	7	7	7	8	9	9	9	9	7	6	7	6	7	64	141
DSM, Class 2 Total	61	62	65	70	72	70	70	63	63	64	65	66	66	67	67	64	55	47	47	47	659	1,250
OR Solar Cap Standard	-	2	2	2	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	9	9
OR Solar Pilot	4	2	2	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10	10
Micro Solar - Hot Water Heating	-	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	1.81	16	34
FOT COB Q3	150	150	150	150	50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	65	32
FOT MidColumbia Q3	-	400	400	400	400	400	400	400	370	400	328	400	400	400	400	400	400	400	400	400	357	375
FOT MidColumbia Q3 - 2	-	271	211	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	48	24
FOT South-Central Oregon/North Cal Q3	-	50	50	50	50	50	50	50	-	50	-	50	50	50	50	50	50	50	50	50	40	43
Annual Additions, Long Term Resources	136	217	196	983	218	863	337	340	808	389	166	242	197	217	580	331	597	245	306	458		
Annual Additions, Short Term Resources	350	1,239	1,425	1,172	1,149	765	802	945	670	921	628	753	851	890	830	952	750	861	939	950		
Total Annual Additions	486	1,456	1,621	2,155	1,367	1,628	1,139	1,285	1,479	1,311	794	995	1,048	1,107	1,410	1,283	1,347	1,106	1,245	1,408		

* Front office transactions (FOT) are not additive. For the 10-Year column, FOT are a 10-year average for 2011-2020, whereas the 20-Year column report a 10-year average for 2021-2030.

Table 5 – Resource Portfolio Differences, Revised Full Energy Gateway Scenario less Energy Gateway-Limited Scenario

	Capacity, MW																				Resource Totals *	
	Resource	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	10 Year	20 Year
East																							
	IC Aero Goshen	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(93)	93	-	-
	SCCT Aero Utah South	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(118)	-	(118)
	Wind, Goshen, 29% Cap Factor	-	-	-	-	-	100	30	-	-	-	-	-	-	-	-	-	-	-	-	-	130	130
	Wind, Utah, 29% Cap Factor	-	-	-	-	-	-	(6)	100	100	100	18	88	-	-	-	-	-	-	-	-	294	400
	Wind, Wyoming, 35% Cap Factor	-	-	-	-	-	-	-	(200)	(200)	(200)	(15)	(73)	(38)	(48)	(20)	(99)	(49)	(78)	(40)	(187)	(440)	(1,087)
	Total Wind	-	-	-	-	-	100	23	(100)	(100)	(100)	3	15	(38)	(48)	(20)	(99)	(49)	(78)	(40)	(187)	(177)	(718)
	DSM, Class 1, Utah, DLC-Residential	-	-	-	-	(7.2)	-	-	-	-	-	-	-	-	-	-	7.2	-	-	-	-	(7)	0
	DSM, Class 2, Utah	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(14.9)	-	(0.1)	-	-	15.8	-	1
	Micro Solar - Hot Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.3	-	-	0
	FOT Mead Q3	-	-	-	-	-	(2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(2)	(2)
	FOT Utah Q3	-	-	-	-	7	-	(5)	(5)	-	(5)	-	(5)	(5)	(5)	7	(0)	-	(0)	(9)	-	(8)	(26)
West																							
	IC Aero, South-Central Oregon/CA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	102	-	-	102
	Wind, Yakima, 29% Cap Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind, Washington, 29% Cap Factor	-	-	-	-	-	13	6	100	100	100	-	-	43	57	26	100	58	95	45	100	319	844
	Wind, Oregon, 29% Cap Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20	-	-	-	84	-	104
	Wind, Walla Walla, 29% Cap Factor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total Wind	-	-	-	-	-	13	6	100	100	100	-	-	43	57	26	120	58	95	45	184	319	948
	DSM, Class 2, Walla Walla	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(0)	(0)
	DSM, Class 2, California/Oregon	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	-	0
	DSM, Class 2 Total	-	-	-	-	-	(0.1)	-	-	-	-	-	-	-	-	-	-	-	-	-	0.1	(0)	(0)
	Micro Solar - Hot Water Heating	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1	1	1	-	2
	FOT MidColumbia Q3	-	-	-	-	-	-	-	-	(5)	-	(5)	-	-	-	-	-	-	-	-	-	(1)	(1)
	Annual Additions, Long Term Resources	-	-	-	-	(7)	113	30	-	-	-	3	15	6	9	(9)	28	9	17	16	(11)		
	Annual Additions, Short Term Resources	-	-	-	-	7	(2)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	(5)	7	(0)	-	(0)	(9)	-		
	Total Annual Additions	-	-	-	-	(0)	111	24	(5)	(5)	(5)	(2)	9	1	4	(2)	28	9	17	7	(11)		

* Front office transactions (FOT) are not additive. For the 10-Year column, FOT are a 10-year average for 2011-2020, whereas the 20-Year column report a 10-year average for 2021-2030.

Table 6 reports the stochastic average PVRR and cost component details for the revised Full Gateway and Gateway-Limited scenarios under the Green Resource Future scenario assuming medium CO_2 and medium natural gas prices. A comparison of these PVRR results with the original Full and Gateway-Limited PVRR results is also provided. As indicated, the generation resource changes, which account for transmission operational constraints, resulted in higher PVRRs for both scenarios. The table also shows that the PVRR difference between the revised Full Gateway and Gateway-Limited scenario portfolios increased by $89 million ($1.084 billion less $995 million) relative to the difference for the original portfolios.

Table 6 – Portfolio Stochastic Average PVRR Comparison, Gateway-Limited vs. Full Gateway Scenarios

	Original Energy Gateway Portfolios			Revised Energy Gateway Portfolios		
Cost Component (Million $)	**Original Gateway-Limited Scenario**	**Original Full Gateway Scenario**	**Difference (Original Gateway Limited less Full Gateway)**	**Revised Gateway-Limited Scenario**	**Revised Full Gateway Scenario**	**Difference (Original Gateway Limited less Full Gateway)**
Variable Costs						
Fuel & O&M	$15,231	$15,048	$183	$14,858	$14,586	$272
Emission Cost	7,409	7,230	179	7,448	7,172	276
FOT's & Long Term Contracts	4,063	4,064	(1)	4,195	4,195	(0)
Demand Side Management	3,373	3,421	(48)	3,657	3,639	18
Renewables	693	693	0	665	665	(0)
System Balancing Sales	(6,458)	(6,387)	(71)	(6,529)	(6,250)	(279)
System Balancing Purchases	2,631	2,740	(109)	2,586	2,744	(158)
Energy Not Served	44	47	(3)	46	38	8
Dump Power	(127)	(127)	0	(125)	(124)	(1)
Reserve Deficiency	0	0	0	0	0	0
Total Variable Costs	$26,858	$26,729	$129	$26,802	$26,666	$136
Capital and Fixed Costs	$12,067	$11,201	$866	$12,693	$11,745	$948
Total PVRR	$38,925	$37,930	$995	$39,495	$38,411	$1,084

Conclusion

Based on these results, PacifiCorp concludes that for future Energy Gateway and other transmission expansion scenarios conducted for the IRP, a review of initial System Optimizer portfolio results in light of operational transmission constraints—followed by manual resource adjustments as needed—is a worthwhile modeling refinement. However, the cost impact is relatively small such that it would not be expected to change relative cost rankings of alternative transmission expansion scenarios. Excluding growth resources as a resource option has a more significant impact, raising portfolio costs due to the higher fixed costs associated with generation plant. The Company will revisit the efficacy of the growth resource approach for the next IRP.

CHAPTER 2 – CLASS 2 DSM DECREMENT STUDY

This section presents the methodology and results of the energy efficiency (Class 2 demand-side management) decrement study. For this analysis, the 2011 IRP preferred portfolio was used to calculate the decrement value ("avoided cost") of various types of Class 2 DSM resources. PacifiCorp will use these decrement values when evaluating the cost-effectiveness of current programs and potential new programs between IRP cycles.

The Class 2 DSM decrement study was enhanced for the 2011 IRP. To align with the resource costs applied for resource portfolio development using the System Optimizer capacity expansion model, cost credits were applied to the Class 2 DSM decrement values reflecting (1) a transmission and distribution (T&D) investment deferral benefit, (2) a generation capacity investment deferral benefit, and (3) a stochastic risk reduction benefit associated with clean, no-fuel resources.[7] Decrement values for two new energy efficiency load shapes were also estimated: residential water heating and "plug" loads (i.e., energy consumed by electronic devices plugged into sockets.)

Modeling Approach

To determine the Class 2 DSM decrement values, PacifiCorp defined 17 shaped Class 2 DSM resources, each at 100 megawatts at the time of peak load, and available starting in 2011 and for the duration of the 20-year IRP study period. In contrast, the valuation study for the 2008 IRP focused on 13 resources. The added resources consist of residential water heating and plug loads for both east and west control areas. Adding these new energy efficiency resources to the analysis is intended to provide a refined valuation for energy savings and further aid in developing program initiatives for such applications as showerheads, heat pump water heaters, and consumer electronics.

Consistent with prior valuation studies, PacifiCorp first determined the system production cost with and without each Class 2 DSM resources using the PaR production cost model in Monte Carlo stochastics mode. The difference in production cost (stochastic mean PVRR) for the two runs indicates the system value attributable to the DSM resource through lower spot market transaction activity and resource re-optimization with the DSM resource in the portfolio. The cost credits mentioned above are then added separately outside of the model, thereby increasing Class 2 DSM decrement values. The resource deferral benefit, as a new step for deriving the decrement values value, is described below. The PaR decrement values were determined for three CO_2 tax scenarios: zero, medium (starting at $19/ton and escalating to $39/ton by 2030), and low-to-very high (starting as $12/ton and escalating to $93/ton by 2030).

[7] Refer to Volume 1, page 147 of the 2011 IRP for a summary of the T&D investment deferral and stochastic risk reduction cost credits applied to the System Optimizer energy efficiency resource options.

Generation Resource Capacity Deferral Benefit Methodology

PacifiCorp used the System Optimizer model to determine the generation resource capacity deferral benefit. The approach is similar to the stochastic production cost difference method, except that only the fixed cost benefit of adding each 100-megawatt Class 2 DSM resource is calculated. This is accomplished by running System Optimizer with a base resource portfolio that excludes each 100-megawatt Class 2 DSM program, and then comparing the fixed portfolio costs against the cost of the same portfolio derived by System Optimizer that includes the DSM program at zero cost. The simulation period is 20 years. As a simplifying assumption, PacifiCorp applied the East "system" load shape for the generic DSM program, which has a capacity planning contribution of 93 percent and a capacity factor of 69 percent. The resource deferral fixed cost benefit is comprised of the deferred capital recovery and fixed operation and maintenance costs of a "next best alternative" resource—a combined-cycle combustion turbine (CCCT). The difference in the portfolio fixed cost represents the resource deferral benefit of the DSM program. (Note that System Optimizer's production cost benefits were not taken into account to avoid double-counting the benefit extracted from stochastic PaR model results.)

Since a 100-megawatt Class 2 DSM is not sufficiently large enough to defer a CCCT, System Optimizer was configured to allow fractional CCCT unit sizes for both the base portfolio and each of the 17 Class 2 DSM resource portfolios. Deferral of CCCT capacity can begin starting in 2015, the year after the Lake Side 2 CCCT is planned to be in service. Note that each Class 2 DSM resource can also defer front office transactions (a market resource representing a range of forward firm market purchase products).

The resource capacity deferral benefit is calculated in two steps:

1. Fixed Cost Deferral Benefit Determination
   Fixed cost benefits are obtained by calculating the differences in annual fixed and capital recovery costs (millions of 2010 dollars) between the base portfolio and the portfolio with the Class 2 DSM program addition. The stream of annual benefits is then converted into a net present value (NPV) using the 2011 IRP discount rate (7.17 percent).
2. Levelized Value Calculation
   The fixed cost resource deferral benefit value obtained from step 1 is divided by the Class 2 DSM program energy in megawatt-hours (also converted to a NPV) to yield a value in dollars per megawatt-hour-year ($/MWh-yr).

This value, along with the T&D investment deferral credit and stochastic risk reduction credit, are added to the PaR model decrement values to yield the final adjusted values.

Class 2 DSM Decrement Value Results

Table 7 reports the NPV levelized avoided costs by DSM resource and CO_2 tax scenario for 2011 through 2030, along with a breakdown of the three cost credits (capacity deferral, T&D investment deferral, and stochastic risk reduction). Tables 8, 9, and 10 report the annual nominal-dollar avoided costs, in $/MWh, for each CO_2 tax scenario. Figures 6 through 11 graphically show the avoided annual cost trends for the three CO_2 tax scenarios by east and west location, along with average annual forward market prices for the relevant location (Palo Verde (PV) for the east and Mid-Columbia (Mid-C) for the west.)

Consistent with the results for the 2008 IRP, the residential air conditioning decrements produce the highest value for both the east and west locations. The water heating (new), plug loads (new), and system load shapes provide the lowest avoided costs. Much of their end use shapes reduce loads during a greater percentage of off-peak hours than the other shapes and during all seasons, not just the summer.

Table 7 – Levelized Class 2 DSM Avoided Costs by Carbon Dioxide Tax Scenario, 20-Year Net Present Value (2011-2030)

			Total Avoided Costs by Carbon Dioxide Tax Scenario, Including all Cost Credits ($/MWh)			Cost Credit Components ($/MWh)			
Resource	Location	Load Factor	Low to Very High	Medium	None	Capacity Resource Deferral	T&D Investment Deferral	Stochastic Risk Reduction	Total Credit
Residential Cooling	East	10%	114.94	116.46	101.55	16.69	11.80	14.98	43.47
Residential Lighting	East	48%	91.17	91.71	78.49	16.69	2.35	14.98	34.02
Residential Whole House	East	35%	94.37	94.89	81.48	16.69	3.23	14.98	34.91
Commercial Cooling	East	20%	102.05	102.96	88.88	16.69	1.91	14.98	33.58
Commercial Lighting	East	48%	93.27	93.59	79.91	16.69	1.97	14.98	33.64
Water Heating	East	57%	90.57	90.95	77.72	16.69	5.83	14.98	37.50
Plug Loads	East	59%	90.16	90.49	77.40	16.69	2.33	14.98	34.00
System Load Shape	East	69%	90.31	90.72	77.53	16.69	1.62	14.98	33.29
Residential Cooling	West	7%	111.17	123.03	112.04	16.69	16.63	14.98	48.30
Residential Heating	West	25%	90.44	99.31	88.69	16.69	5.59	14.98	37.26
Residential Lighting	West	48%	88.82	97.81	88.02	16.69	2.48	14.98	34.15
Commercial Cooling	West	16%	96.04	106.31	96.43	16.69	2.60	14.98	34.27
Residential Whole House	West	49%	88.81	97.96	87.86	16.69	2.03	14.98	33.70
Commercial Lighting	West	48%	89.40	98.56	88.86	16.69	2.20	14.98	33.87
Water Heating	West	56%	87.35	96.12	86.53	16.69	7.11	14.98	38.79
Plug Loads	West	59%	87.61	96.35	86.72	16.69	2.46	14.98	34.13
System Load Shape	West	71%	87.38	96.26	86.54	16.69	1.75	14.98	33.42

Table 8 – Annual Nominal Class 2 DSM Avoided Costs, No CO_2 Tax Scenario, 2011-2030

		Avoided Cost Values (Nominal $/MWh)									
Resource	**Actual Load Factor**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
EAST											
Residential Cooling	10%	92.59	93.45	98.67	96.34	101.80	98.22	96.60	97.05	98.60	97.21
Residential Lighting	48%	68.52	71.88	75.53	76.95	79.37	77.68	77.26	75.56	75.80	77.67
Residential Whole House	35%	71.53	74.73	78.69	79.45	81.63	80.27	79.94	77.98	78.73	80.67
Commercial Cooling	20%	78.04	80.13	85.32	84.93	89.12	86.45	85.23	85.02	86.60	87.68
Commercial Lighting	48%	69.01	72.91	77.14	77.66	80.19	78.99	78.08	77.13	78.32	79.02
Water Heating	57%	67.18	70.81	74.26	75.81	78.05	76.78	76.36	74.80	75.40	77.29
Plug Loads	59%	67.15	70.61	74.11	75.52	77.67	76.22	76.17	74.64	75.42	76.54
System Load Shape	69%	67.17	70.50	74.01	75.23	77.42	76.31	75.89	74.81	75.50	76.78
WEST											
Residential Cooling	7%	87.50	93.55	98.82	103.91	110.65	110.55	108.64	109.64	113.62	115.96
Residential Heating	25%	70.91	76.58	81.06	84.69	85.77	85.61	85.78	86.51	89.45	91.47
Residential Lighting	48%	69.00	74.09	78.90	83.43	86.40	85.48	84.82	86.34	88.94	90.75
Commercial Cooling	16%	74.58	79.96	84.81	89.76	94.93	94.49	93.23	95.07	97.84	100.16
Residential Whole House	49%	68.87	74.32	78.88	83.14	85.81	85.12	84.74	86.14	88.73	90.75
Commercial Lighting	48%	68.94	74.78	79.90	84.42	87.23	86.57	86.08	87.13	89.46	91.68
Water Heating	56%	67.78	72.97	77.56	82.04	84.79	84.09	83.45	84.93	87.26	89.23
Plug Loads	59%	68.10	73.23	77.85	82.15	84.81	84.20	83.75	85.01	87.57	89.47
System Load Shape	71%	67.69	72.87	77.49	82.00	84.66	84.11	83.54	84.90	87.31	89.41

		Avoided Cost Values (Nominal $/MWh)									
Resource	**Actual Load Factor**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
EAST											
Residential Cooling	10%	102.98	105.51	106.53	109.80	108.14	103.44	102.23	123.84	127.89	137.29
Residential Lighting	48%	79.83	81.78	82.95	82.03	83.11	82.89	81.40	91.99	93.97	100.83
Residential Whole House	35%	82.57	84.72	85.49	86.08	86.83	86.64	83.04	96.68	98.67	106.22
Commercial Cooling	20%	90.70	92.79	94.83	96.95	95.40	93.63	91.82	107.39	110.82	118.31
Commercial Lighting	48%	80.99	83.36	84.90	84.92	85.20	84.32	82.21	94.02	97.11	104.06

		Avoided Cost Values (Nominal $/MWh)									
Resource	**Actual Load Factor**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Water Heating	57%	79.38	81.02	82.00	82.11	83.18	82.88	80.68	92.25	93.94	100.95
Plug Loads	59%	78.87	80.54	81.88	81.80	82.29	82.16	80.79	91.57	93.24	100.38
System Load Shape	69%	78.74	80.98	82.21	82.41	82.97	82.52	80.69	92.46	94.55	101.68
WEST											
Residential Cooling	7%	120.27	123.27	124.84	125.63	125.40	129.01	133.33	138.61	138.61	143.17
Residential Heating	25%	92.80	95.16	97.02	98.79	99.22	104.26	103.19	107.04	108.91	111.73
Residential Lighting	48%	93.08	95.64	97.17	99.10	98.70	102.28	103.77	108.10	109.58	112.83
Commercial Cooling	16%	103.11	105.94	107.30	108.81	108.76	111.45	114.54	119.99	120.88	124.49
Residential Whole House	49%	92.90	95.35	96.83	98.67	98.66	102.84	103.53	107.85	109.37	112.47
Commercial Lighting	48%	93.73	96.29	98.04	99.81	99.82	103.61	104.89	109.10	110.91	114.12
Water Heating	56%	91.56	93.78	95.40	97.39	97.37	100.54	101.92	106.01	107.97	110.79
Plug Loads	59%	91.64	94.06	95.52	97.55	97.30	100.76	102.00	106.38	108.17	110.99
System Load Shape	71%	91.59	93.94	95.49	97.36	97.34	100.84	101.95	106.36	108.06	110.84

Table 9 – Annual Nominal Class 2 DSM Avoided Costs, Low to Very High CO_2 Tax Scenario, 2011-2030

		Avoided Cost Values (Nominal $/MWh)									
Resource	**Actual Load Factor**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
EAST											
Residential Cooling	10%	89.02	91.10	92.33	92.16	103.87	104.22	101.20	107.09	108.23	107.72
Residential Lighting	48%	66.01	69.58	70.80	71.90	82.56	83.19	84.43	84.44	85.99	88.06
Residential Whole House	35%	68.62	72.05	73.32	74.41	85.38	85.61	86.07	86.87	88.69	90.57
Commercial Cooling	20%	74.91	78.03	79.48	80.02	92.09	92.05	92.18	94.33	95.64	97.16
Commercial Lighting	48%	66.77	70.07	71.87	72.75	83.71	84.70	85.82	85.88	87.70	90.14
Water Heating	57%	64.81	68.17	69.37	70.79	81.39	82.33	83.15	83.56	85.45	87.50
Plug Loads	59%	64.77	68.02	69.74	70.70	80.96	82.08	83.29	83.18	84.54	87.26
System Load Shape	69%	64.92	67.96	69.35	70.61	81.02	82.00	82.79	83.20	84.55	86.87
WEST											
Residential Cooling	7%	81.27	85.07	86.47	88.00	97.88	100.55	101.45	105.26	108.10	110.90
Residential Heating	25%	65.81	69.58	71.51	72.85	78.56	80.34	82.14	84.17	86.31	89.79

		Avoided Cost Values (Nominal $/MWh)									
Resource	**Actual Load Factor**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Residential Lighting	48%	63.51	66.58	68.62	69.88	77.33	78.88	80.28	82.87	85.31	88.27
Commercial Cooling	16%	69.05	71.80	73.84	75.16	84.02	86.47	87.30	90.75	93.15	95.89
Residential Whole House	49%	63.50	66.85	68.74	69.99	77.15	78.85	80.42	82.88	85.08	88.07
Commercial Lighting	48%	63.63	66.80	68.84	70.10	77.71	79.31	80.95	83.31	85.71	89.06
Water Heating	56%	62.41	65.52	67.55	68.75	75.92	77.70	79.10	81.50	83.84	86.53
Plug Loads	59%	62.69	65.88	67.74	69.05	76.15	77.70	79.31	81.75	84.10	86.86
System Load Shape	71%	62.33	65.60	67.45	68.71	75.84	77.58	79.08	81.44	83.94	86.53

		Avoided Cost Values (Nominal $/MWh)									
Resource	**Actual Load Factor**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
EAST											
Residential Cooling	10%	115.85	123.61	128.08	137.47	142.06	143.42	154.90	180.57	195.11	218.30
Residential Lighting	48%	92.62	98.32	101.69	107.97	114.59	120.87	127.13	145.77	155.11	173.70
Residential Whole House	35%	95.44	101.09	105.17	112.72	118.69	125.05	131.36	153.26	162.52	182.70
Commercial Cooling	20%	104.73	109.14	114.83	123.93	130.80	133.09	140.06	163.32	172.93	200.70
Commercial Lighting	48%	94.91	100.06	105.47	111.87	117.96	124.03	130.47	151.20	162.60	182.58
Water Heating	57%	92.12	96.97	101.95	108.16	114.88	121.02	127.93	146.87	156.64	177.16
Plug Loads	59%	91.66	96.70	101.49	107.16	114.32	120.32	126.73	145.55	154.26	175.57
System Load Shape	69%	91.99	96.97	102.03	107.61	114.12	121.03	127.26	146.11	156.69	177.64
WEST											
Residential Cooling	7%	115.53	122.06	127.58	133.97	141.79	152.37	157.59	170.65	179.22	189.63
Residential Heating	25%	91.99	96.35	102.37	109.15	116.02	131.46	131.07	138.81	148.06	156.39
Residential Lighting	48%	90.78	96.25	101.85	108.30	115.04	127.27	130.17	139.61	148.59	156.89
Commercial Cooling	16%	99.30	104.81	110.54	116.53	123.95	133.70	138.61	150.45	159.46	167.57
Residential Whole House	49%	90.98	95.99	101.64	108.18	115.27	127.79	129.88	139.27	148.30	156.82
Commercial Lighting	48%	91.70	96.89	102.75	109.04	115.95	128.63	131.20	140.77	150.07	158.85
Water Heating	56%	89.26	94.46	100.05	106.42	113.45	125.22	127.93	136.94	146.45	154.84
Plug Loads	59%	89.49	94.60	100.50	106.75	113.61	125.58	128.42	137.40	146.68	155.09
System Load Shape	71%	89.51	94.43	100.23	106.42	113.37	125.63	128.18	137.32	146.53	155.10

Table 10 – Annual Nominal Class 2 DSM Avoided Costs, Medium CO_2 Tax Scenario, 2011-2030

		Avoided Cost Values (Nominal $/MWh)									
Resource	**Actual Load Factor**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
EAST											
Residential Cooling	10%	92.01	91.50	95.47	90.41	116.85	114.75	113.45	116.39	118.93	120.59
Residential Lighting	48%	66.61	69.53	71.34	70.94	92.99	93.51	93.38	93.64	94.83	97.91
Residential Whole House	35%	69.58	72.28	74.46	73.30	95.62	95.85	95.98	96.54	97.25	101.50
Commercial Cooling	20%	76.46	77.82	81.97	78.94	103.42	103.58	102.17	102.89	105.32	109.07
Commercial Lighting	48%	67.25	70.38	73.04	71.88	93.98	95.26	95.04	95.71	96.77	100.30
Water Heating	57%	65.18	68.06	69.97	69.89	91.92	92.64	92.97	92.54	93.96	97.41
Plug Loads	59%	65.16	67.97	70.05	69.56	91.40	92.10	92.42	92.15	94.08	96.67
System Load Shape	69%	65.12	68.04	70.00	69.38	91.26	92.30	92.18	92.08	94.11	97.25
WEST											
Residential Cooling	7%	85.37	92.78	94.94	97.51	122.94	126.87	122.17	124.77	130.24	132.77
Residential Heating	25%	71.42	77.64	79.39	81.76	97.95	99.54	99.23	100.19	104.18	106.21
Residential Lighting	48%	66.78	72.50	74.85	76.94	97.90	99.53	97.51	99.69	103.47	106.07
Commercial Cooling	16%	71.77	78.06	80.78	83.07	107.22	109.27	105.19	108.42	112.10	116.03
Residential Whole House	49%	67.45	73.49	75.67	77.80	97.76	99.54	97.56	99.55	103.43	106.03
Commercial Lighting	48%	67.07	73.49	75.70	78.00	98.68	100.19	97.82	100.18	103.92	107.07
Water Heating	56%	65.47	71.34	73.54	75.71	96.26	97.73	95.86	98.04	101.70	104.37
Plug Loads	59%	65.86	71.77	73.90	75.96	96.54	97.84	96.18	98.14	101.85	104.85
System Load Shape	71%	65.66	71.57	73.79	75.85	96.25	97.78	96.04	98.12	101.86	104.56

		Avoided Cost Values (Nominal $/MWh)									
Resource	**Actual Load Factor**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
EAST											
Residential Cooling	10%	125.57	131.25	133.34	142.19	141.47	131.18	130.37	153.07	158.43	171.00
Residential Lighting	48%	101.70	104.18	106.66	109.14	110.57	108.57	107.94	118.67	123.53	130.43
Residential Whole House	35%	104.62	107.48	110.95	114.02	114.98	111.90	110.68	123.55	128.44	136.13
Commercial Cooling	20%	114.81	117.06	121.00	125.42	125.90	119.41	117.43	135.09	140.99	152.28

		Avoided Cost Values (Nominal $/MWh)									
Resource	**Actual Load Factor**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Commercial Lighting	48%	104.02	105.75	110.04	112.67	114.01	110.31	109.83	121.35	126.81	136.27
Water Heating	57%	101.05	103.59	106.94	109.61	111.00	108.15	107.17	118.92	122.52	131.34
Plug Loads	59%	100.36	102.51	106.08	108.83	109.89	107.38	106.80	117.64	121.95	130.47
System Load Shape	69%	100.75	102.91	106.59	109.26	109.93	107.93	107.42	118.90	123.86	131.88
WEST											
Residential Cooling	7%	135.63	140.77	146.35	152.81	150.62	149.83	147.88	158.04	160.17	168.14
Residential Heating	25%	108.12	111.39	116.14	120.47	120.99	123.05	119.50	123.79	127.27	131.90
Residential Lighting	48%	108.09	111.69	117.11	121.96	121.47	121.70	119.29	125.50	129.29	133.97
Commercial Cooling	16%	117.95	122.18	128.59	133.56	132.06	130.80	128.51	137.31	140.79	146.76
Residential Whole House	49%	107.89	111.61	116.71	121.52	121.45	121.57	119.04	125.02	128.36	133.51
Commercial Lighting	48%	108.95	112.32	117.74	122.87	122.05	122.48	120.08	126.55	130.75	135.41
Water Heating	56%	106.22	109.93	114.91	120.15	119.37	119.33	116.97	123.06	126.97	131.66
Plug Loads	59%	106.36	110.07	115.23	119.84	119.50	119.33	117.21	123.24	127.08	131.90
System Load Shape	71%	106.46	109.92	115.12	119.93	119.67	119.41	117.23	123.11	127.20	131.91

Figure 6 – East Class 2 DSM Nominal Avoided Cost Trends, Low to Very High CO_2 Tax Scenario

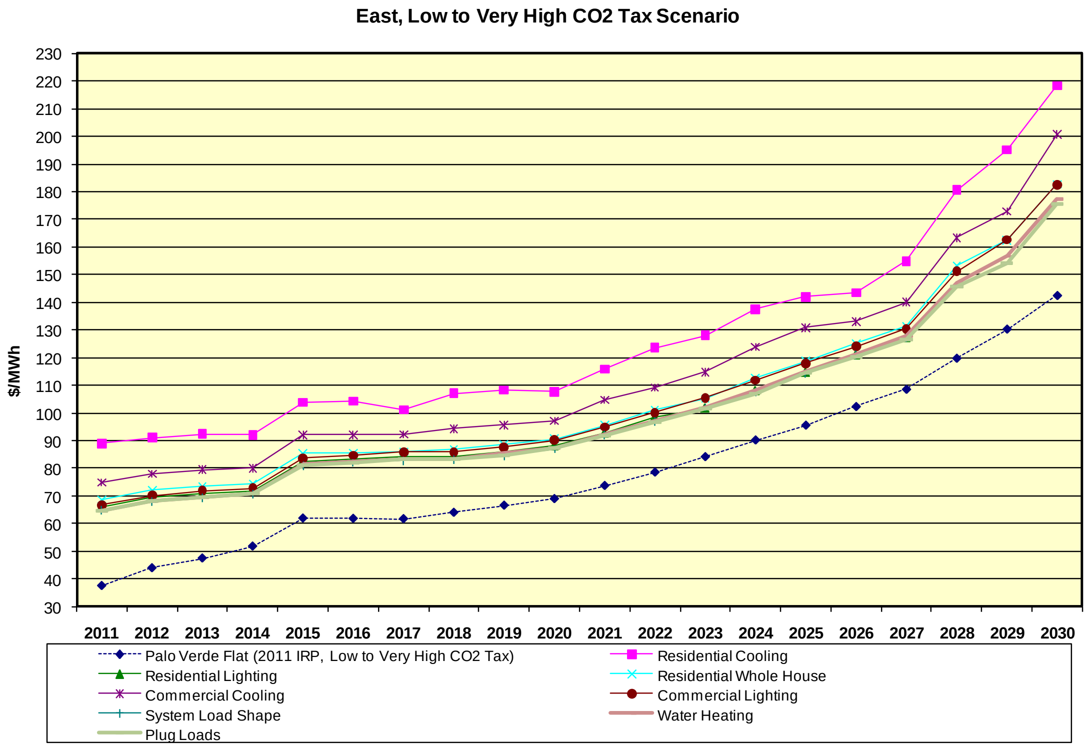


Figure 7 – West Class 2 DSM Nominal Avoided Cost Trends, Low to Very High CO_2 Tax Scenario

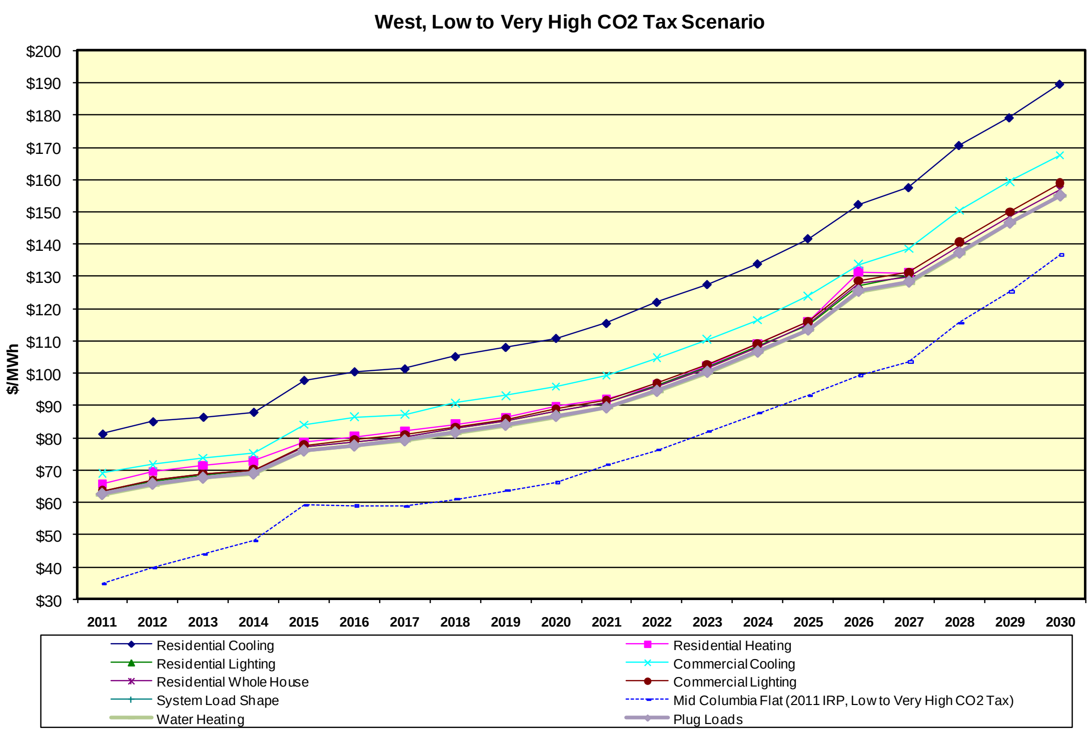


Figure 8 – East Class 2 DSM Nominal Avoided Cost Trends, Medium CO_2 Tax Scenario

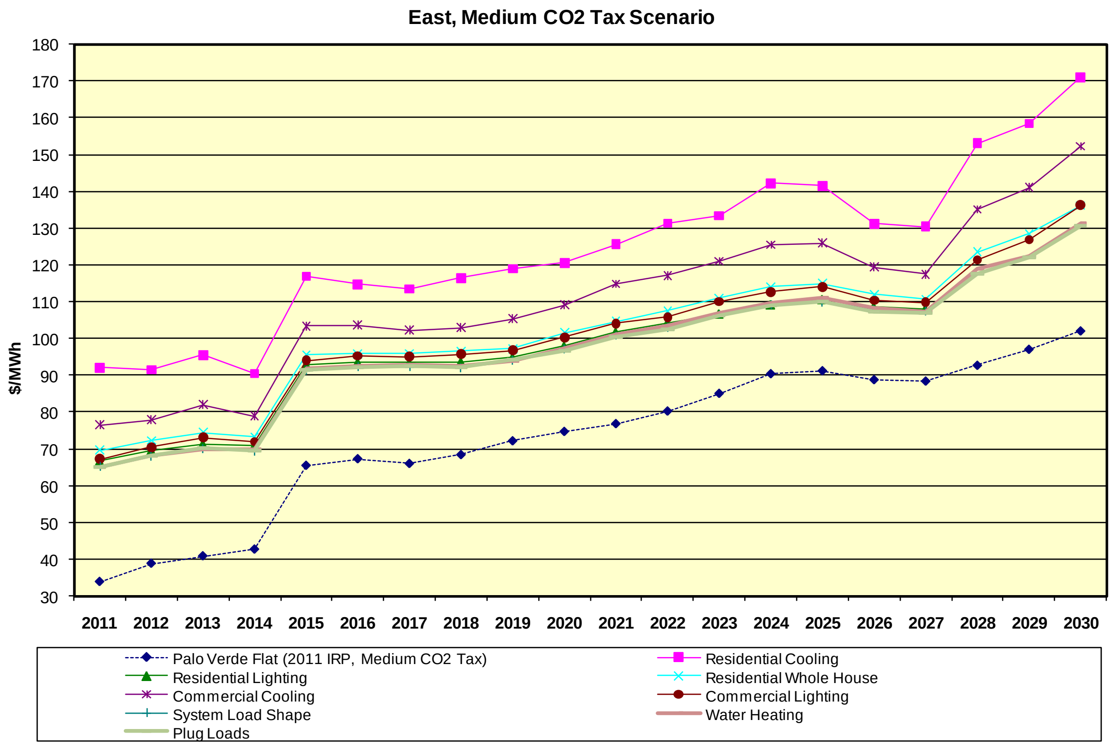


Figure 9 – West Class 2 DSM Nominal Avoided Cost Trends, Medium CO_2 Tax Scenario

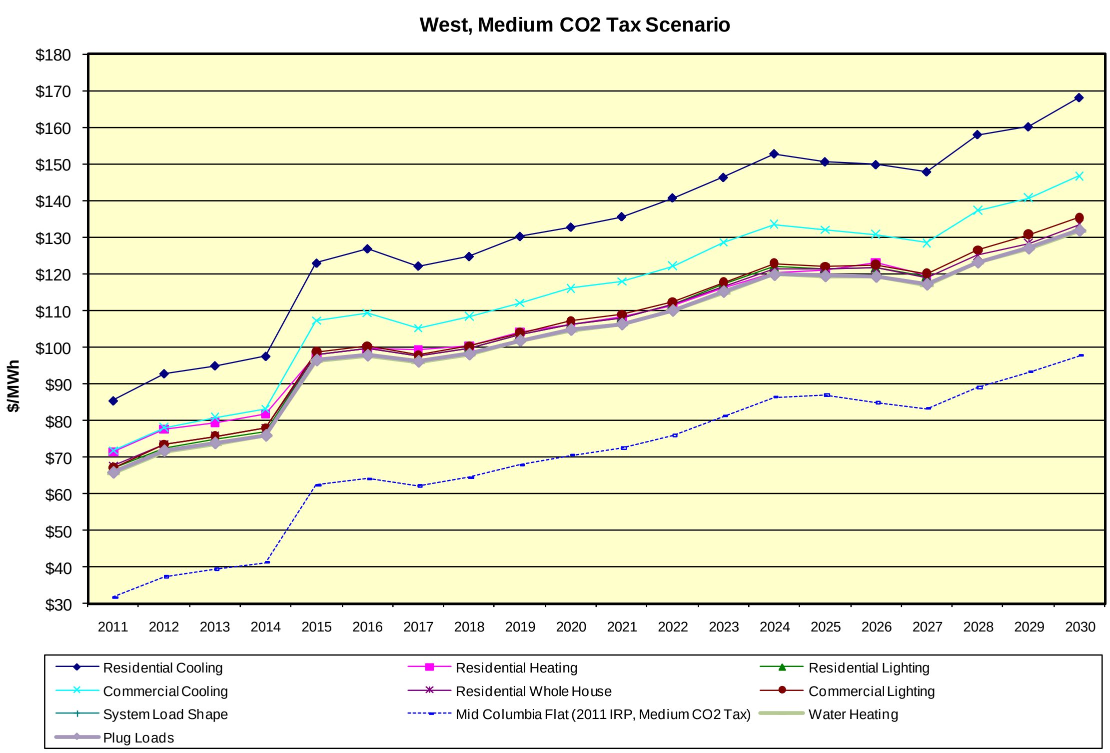


Figure 10 – East Class 2 DSM Nominal Avoided Cost Trends, No CO_2 Tax Scenario

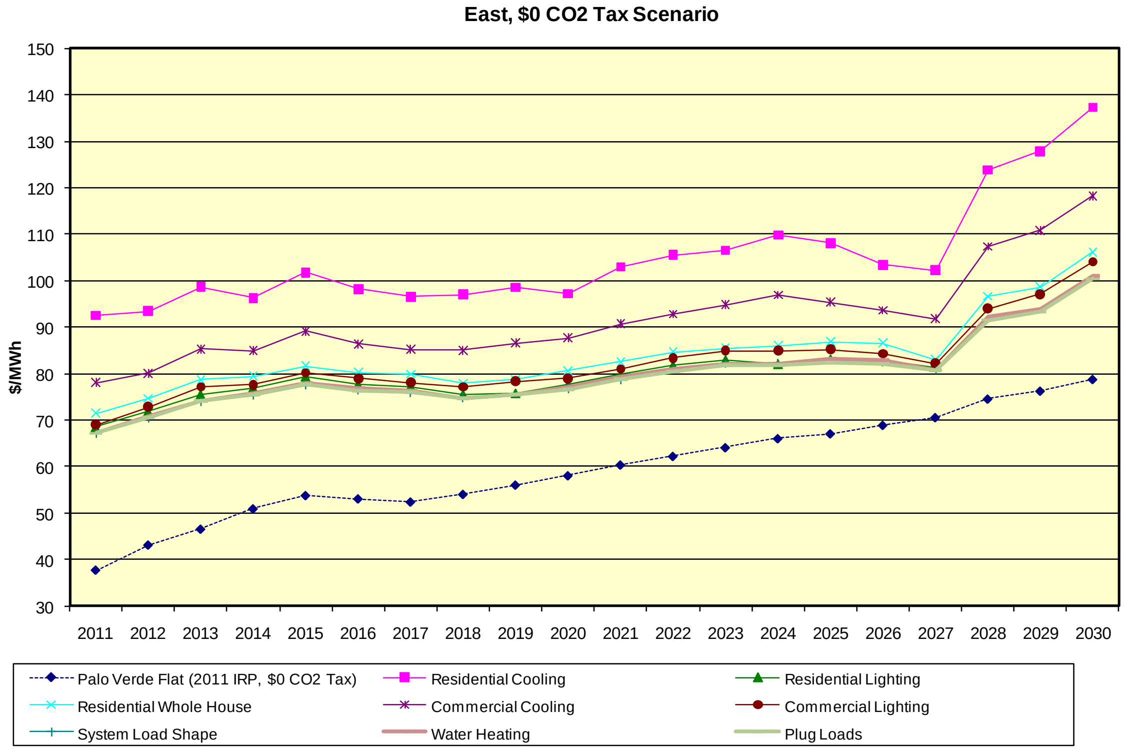
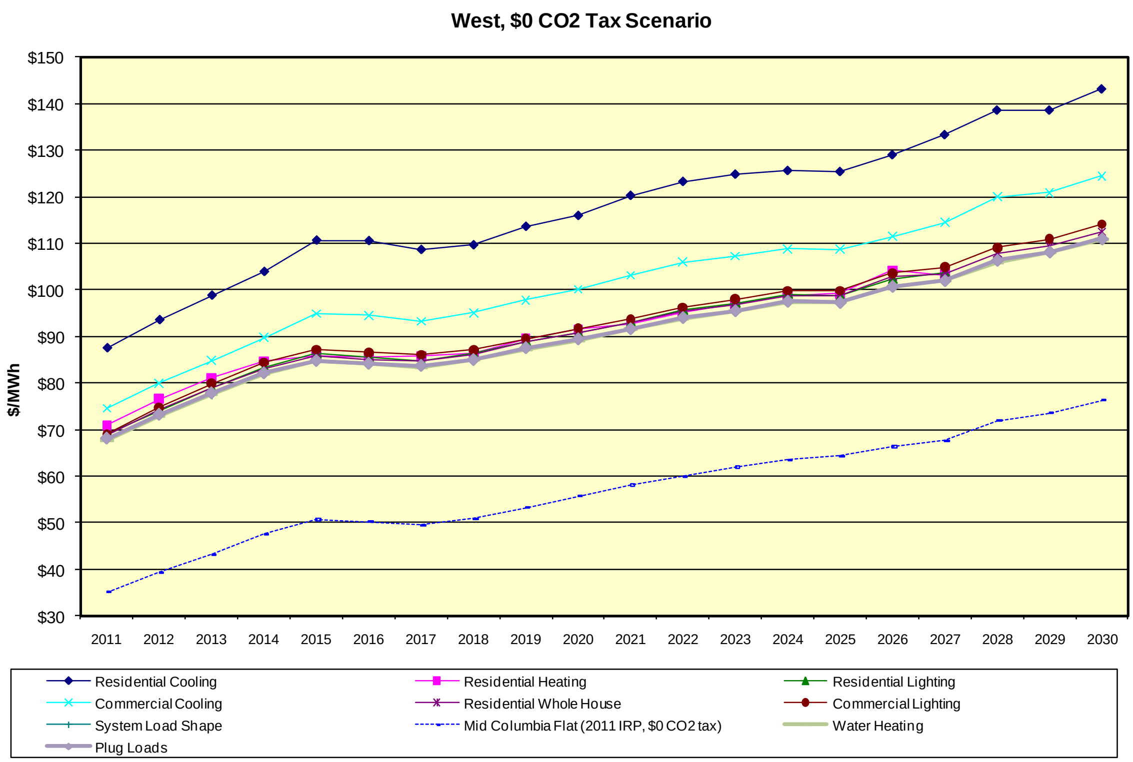


Figure 11 – West Class 2 DSM Nominal Avoided Cost Trends, No CO_2 Tax Scenario



CHAPTER 3 – APPRAISAL OF INTERWEST ENERGY ALLIANCE'S WIND CAPITAL COST AND CAPACITY FACTOR RECOMMENDATIONS

Introduction

At the 2011 IRP public input meeting held December 15, 2010, Wasatch Wind (a wind project developer headquartered in Utah) and other participants contended that PacifiCorp's planning capital cost value for east-side wind projects were too high, while the planning capacity factor value—35 percent for Wyoming and 29 percent for Utah—were too low. PacifiCorp agreed to review information supplied by participants and provide its assessment to all IRP public participants, also noting that it was too late to incorporate such information into the portfolio development process.[8] At the Company's discretion, a sensitivity analysis on wind selection impacts of alternative capital cost and capacity factor values may be conducted as warranted based on its findings. On January 10, 2011, PacifiCorp received wind capital cost and net capacity factor information from Interwest Energy Alliance (IEA). This information is included as Appendix A. The sections below provide PacifiCorp's response to both IEA's capital cost and capacity factor recommendations.

Capital Costs

The Company has reviewed the IEA's "ITC Grant Recipient" project cost overview and, while informative, the information is not viewed as a suitable replacement for PacifiCorp's own wind cost information. The reasons are summarized below.

First, The IEA information is generally not representative of projects that would interconnect to PacifiCorp's transmission system. None of the example projects are located in Wyoming and only one is located in Utah. In contrast, PacifiCorp's wind capital cost estimates are informed by both actual project costs and regionally-adjusted capital costs used in an independently produced model (ICF International's IPM® model). The IPM model supports development of PacifiCorp's forward price curve and, therefore, assumptions within the IPM model are inherently important as it relates to the Company's IRP.

Second, the costs represented by IEA are derived by taking United States Treasury Department's ITC Grants stemming from the 2009 Stimulus Bill and dividing by 0.285. The result is shown on a cost per unit basis ($/MW). IEA represents the divisor as being an adjustment factor to convert the amount of cost qualifying for the cash grant into "total wind project costs". It is not known if the "total wind project costs" being promoted by IEA can accurately be compared to the capital

[8] PacifiCorp presented and discussed resource option characteristics, including those for wind, at the August 4, 2010, public input meeting. The subsequent meeting report, provided to IRP participants on October 5, 2010 and posted to PacifiCorp's IRP Web site, included the detailed table of resource characteristics.

cost assumptions used by PacifiCorp in its most recent version of the IRP. PacifiCorp's cost estimate is intended to represent all costs to develop, permit, construct, own and operate a representative wind-powered generation resource using PacifiCorp's weighted average cost of capital and with an assumed economic life of 25 years.

IEA's estimate appears to rely on two key assumptions: (1) that IEA's view of "total wind project costs" includes all of the factors included in PacifiCorp's cost estimate, and (2) IEA has accurately interpreted Internal Revenue Service (IRS) guidance associated with such grants. It is uncertain if IEA's interpretation of IRS guidance as applied to such a limited set of western project data can, or should, serve as definitive prediction of all costs that will affect the total bus bar costs of future wind-powered generation resources as seen from the customer's perspective. For example, it is uncertain what portion of transmission-related costs the IRS considers as being "qualifying costs" under the 2009 Stimulus Bill and how transmission-related costs (e.g., generation tie line and/or transmission collector system costs) will change as future projects are brought to fruition.

Third, the IEA's sample data set data represents projects that were poised and ready to qualify for a cash grant under the 2009 Stimulus Act. As such, the data set does not account for significant new and prospective environmental regulatory actions or other policy decisions that are expected to change development costs for future projects. Examples include (1) Wyoming's Greater sage-grouse core breeding area plan, (2) the effect of emerging "Land-Based Wind Energy Guidelines" by the U.S. Fish and Wildlife Service, and (3) federal, state or local tax and/or permitting policies. (As noted above, none of the sample projects in the IEA data set include projects in Wyoming, which are subject to Wyoming's sales tax and generation excise tax policies.)

Fourth, even if IEAs estimates include all of the cost elements included in PacifiCorp's estimate, because of the factors that led to the 2009 Stimulus Act, it is impossible to ascertain what cost concessions developers were able to extract from major equipment suppliers and/or construction contractors during then-current market conditions. Furthermore, because PacifiCorp is planning for the long-term, any long-run cost improvements can reasonably be expected to be offset to some degree by supply chain pricing dynamics and/or the effects of domestic and/or international market demand, depth and liquidity. Finally, it can also reasonably be expected that market forces will result in the development of increasingly less desirable and/or more costly sites as the more optimal sites are utilized (i.e., moving higher up the cost-supply curve).

In summary, PacifiCorp does not see definitive evidence suggesting that the capital cost estimates in the IRP for wind-powered generation resources are inappropriately high. However, to get a sense for what IEA's capital cost recommendation would do in terms of a wind resource selection impact, we refer to the alternate wind integration cost sensitivity results on page 244 of the 2011 IRP. The lower wind integration cost used for this sensitivity study, $5.38/MWh, equates to a fixed cost reduction of $195/kW. Using the alternative wind integration cost value resulted in 81 MW of additional wind. Based on the $346/kW capital cost reduction advocated by IEA ($2,239/kW from IRP Table 6.5 less $1,893/kW from page 1 of IEA's materials), the capacity impact is not likely to exceed 150 MW.

Capacity Factors

IEA makes multiple generalized assumptions and, using these assumptions as a basis, suggests that PacifiCorp should use a 43.6% or higher net capacity factor (NCF) for modeling future Wyoming wind projects. Below is a discussion of these generalized assumptions and their suitability for characterizing NCFs for use in the IRP context.

IEA assumes that the NCF associated with PacifiCorp owned wind resources in Wyoming should serve as a base-level assumption for future wind projects. IEA determines the average NCF for seven selected resources. Using this average NCF, IEA represents that it can "back into" an annual average wind speed (in meters per second) that should be associated with future wind projects constructed in Wyoming. IEA concludes that 8.6 meters per second should be assumed as the annual average wind speed. Using this average wind assumption, IEA further concludes a theoretical NCF increase of 112 percent can be achieved if a General Electric (GE) model 1.5 megawatt (MW) "XLE" wind turbine generator (WTG) is used instead of a GE 1.5 MW "SLE" WTG. The GE 1.5 MW XLE WTG has longer blades and a larger rotor diameter (82.5 meters) than the GE 1.5 MW SLE WTG (77 meter rotor diameter). IEA considers the GE 1.5 XLE to be an "advanced" WTG design. IEA likewise considers the Vestas V90 and Siemens 2.3 MW WTGs, with 90 meter and 101 meter rotor diameters respectively, to be advanced WTG designs. Applying the 112 percent enhancement to the Dunlap I NCF, IEA represents it has demonstrated its theory.

In short IEA suggest that PacifiCorp should assume that all future wind projects in Wyoming are suitable for WTGs with increased rotor diameters. While PacifiCorp agrees that WTG design evolutions may favorably impact performance for those sites for which they are suitable, the Company makes the following observations regarding IEA's NCF recommendation and the assumptions it is based on.

First, IEA's NCF recommendation assumes all Wyoming wind developments could utilize WTGs with increased rotor diameters. In arriving at this conclusion, IEA points toward an unreferenced GE determination that, depending on final layouts and turbulence intensity, the GE XLE model is "meteorologically suitable for some wind projects at 7500' altitude with annual average wind speeds of 8.5 m/s to over 10 m/s". IEA's representation that WTG suitability for a site is primarily based on average annual wind speed and turbulence intensity is flawed. The suitability of a WTG model(s) for any given site can only be determined using a site specific mechanical loads assessment performed by the turbine manufacturer. IEA has provided no evidence of such assessments demonstrating that WTGs with rotor diameters as large as 101 meters are broadly suitable for use in Wyoming. Further, IEA fails to adequately discuss that WTG suitability is often driven by 50-year peak gusts and turbulence intensity at high wind speeds. Without a sufficient amount of reliable data from the site towers, it is difficult to conclusively determine if a WTG is suitable for a given site, let alone if specific WTG models are broadly suitable for use in Wyoming. Indeed, manufacturers may require more site data to be collected to verify that their WTGs are suitable, and in the event that site conditions are more extreme than was indicated by the data provided to the manufacturer (e.g., higher wind gusts or higher overall average wind speeds), they may not honor warranties in the event of failures associated with greater than estimated environmental conditions at the site. For these reasons, PacifiCorp's IRP does not rely on generalized WTG assumptions.

Second, IEA's assumed NCF improvement (12 percent applied broadly) associated with the GE XLE WTG over the GE SLE WTG is significantly higher than that indicated by a recent Company procurement process. In its "2009R" renewable Request for Proposals, PacifiCorp received two separate bids from the same developer using the same site and based on the GE SLE WTG versus GE XLE WTG. The capacity factor difference was only 1.8 percentage points in favor of the GE 1.5 XLE WTG, a difference of 4.6 percent. This is in contrast to the 12 percent capacity factor improvement recommended by IEA.[9] Of note is that the bid based on the GE XLE WTG commanded a price premium relative to the bid based on the GE SLE WTG. PacifiCorp further notes that IEA's recommendation to reduce assumed capital costs (discussed above) relied on information where the model of WTG was not disclosed.

Finally, in selecting the seven wind projects that serve as the source of the average NCF assumption that, in turn, serves as the starting point for all of IEA's subsequent assumptions and resulting adjustments, IEA fails to consider all of PacifiCorp's owned and contracted wind resources in Wyoming. IEA dismisses this choice by stating that "We did not average the capacity factors for projects in western Wyoming as those projects do not reflect the higher capacity factors experienced in the central Wyoming projects". PacifiCorp believes there is no basis to assume that all future Wyoming resources would be restricted to locations in just central Wyoming. PacifiCorp's IRP assumption of a 35 percent NCF for planning purposes is informed by those wind resources that are actually in the current portfolio. The NCF for operating Wyoming wind resources—both owned and acquired through power purchase contracts—is 34.98 percent based on weighted averaging with each resource's nameplate capacity. This weighted average NCF reflects capacity factor updates utilized in the latest Wyoming General Rate Case. Of note is that Dunlap I has a NCF of 36.4 percent rather than the 38.6 percent NCF cited by IEA. This is in comparison to IEA's starting-point assumption of 37.6 percent.

PacifiCorp emphasizes that the NCF assumption in the IRP is not intended to be based on idealistic or theoretical assumptions of what may find its way into the portfolio. Indeed, NCF is not what will determine which individual renewable resources will be added to PacifiCorp's portfolio in the future. The cost and risk to customers of those case-by-case decisions is what will be the determining factor.

Conclusion

For the reasons cited above, PacifiCorp does not find IEA's recommendations to change the IRP cost or NCF assumptions associated with wind-powered generation resources to be warranted. PacifiCorp will continue to rely on its procurement practice of making decisions regarding individual renewable resource additions on a case-by-case basis, and the standard for such decisions will continue to be established regulatory principals regarding prudence and benefit to customers.

[9] Mechanical load suitability of the alternate GE XLE WTG is uncertain.

APPENDIX A – COMMENTS AND DATA SUBMISSION FROM INTERWEST ENERGY ALLIANCE

INTERWEST
ENERGY ALLIANCE

10 January 2011

Pete Warnken
PacifiCorp IRP Team
IRP@PacifiCorp.com

Re: 2011 IRP Modeling

Dear Mr. Warnken:

Interwest Energy Alliance appreciates the opportunity to provide input to promote accurate cost analysis of wind and solar energy in the public process related to development of PacifiCorp's 2011 IRP. We ask you to consider some of the enclosed materials related to wind development costs and net capacity factors as you develop modeling inputs and consider the results. Several questions raised at the public meeting held on December 15, 2010, by Wasatch Wind and others, which require further response and consideration. We want to provide any support you may require to inform the resource planning process related to these issues.

First, wind costs are lower than PacifiCorp assumes in its modeling, due to decreases in turbine prices and related costs. See attached Schedule 1 "Recent Turbines Using the ITC Grant Proxy", and "ITC Grant Recipients – CAPEX For U.S. Wind Farms" attached thereto.

Second, please consider the information related to net capacity factors attached as Schedule 2, with Appendix A "Wind Turbine Brochure Information" and Appendix B "Summary of Utah WREZ Prospects" attached thereto. Your modeling should reflect the increased net capacity factors available from this new equipment available to the market.

We appreciate the opportunity to provide this input.

Best regards.

Sincerely,

Craig Cox
Executive Director

P.O. Box 261311, Denver, Colorado 80226 ◆ 303-679-9331 ◆ www.interwest.org

Schedule 1

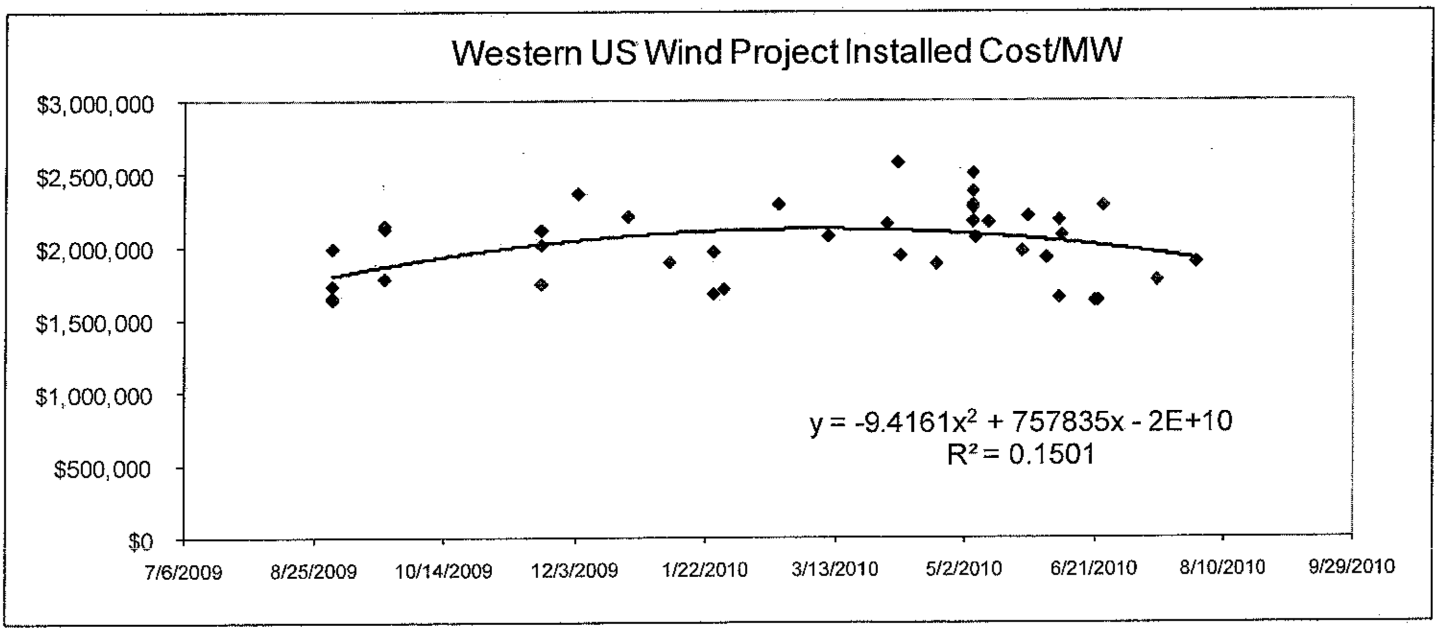
Recent Turbine Prices using the ITC Grant Proxy

Under the 2009 Stimulus bill, wind projects became eligible to receive a cash grant (the "ITC Grant") from the US Treasury Department equal to 30% of the "qualified costs" of a wind project within 60 days after the wind project achieved commercial operations. Qualified costs include approximately 95% of total wind project costs.

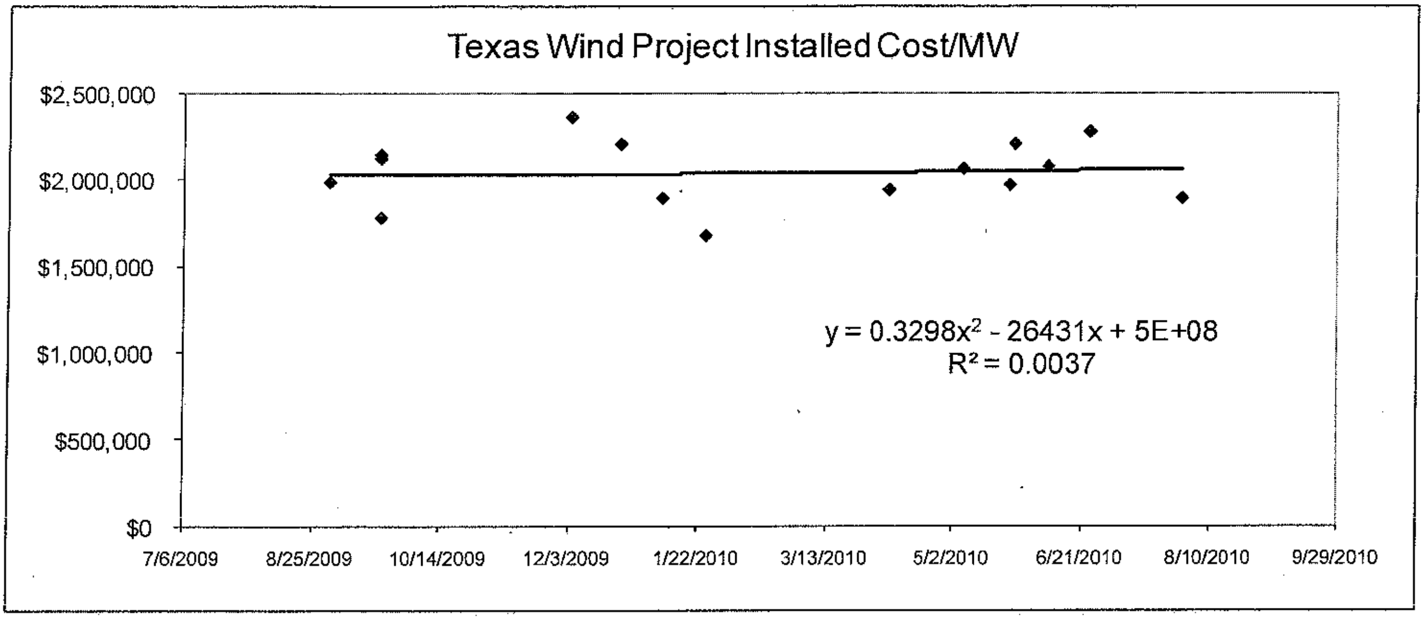
The US Treasury Department published the recipient, date, and amount of the ITC Grant. Based on the recipient information, we were able to identify the location of the wind project (and the related MW). Based on the amount of the ITC Grant, we were able to approximate the cost of the wind project. This cost approximation assumes that since the ITC Grant represents 30% of 95% of the wind project costs, then by simply taking the ITC Grant amount and dividing it by the product of 30% and 95% (or 28.5%) the total wind project costs are calculated. For example, assume that the ITC Grant was $100 million. Based on the above assumptions, the wind project cost would be approximated at $350.9 million ($100 million / (30% x 95%)).

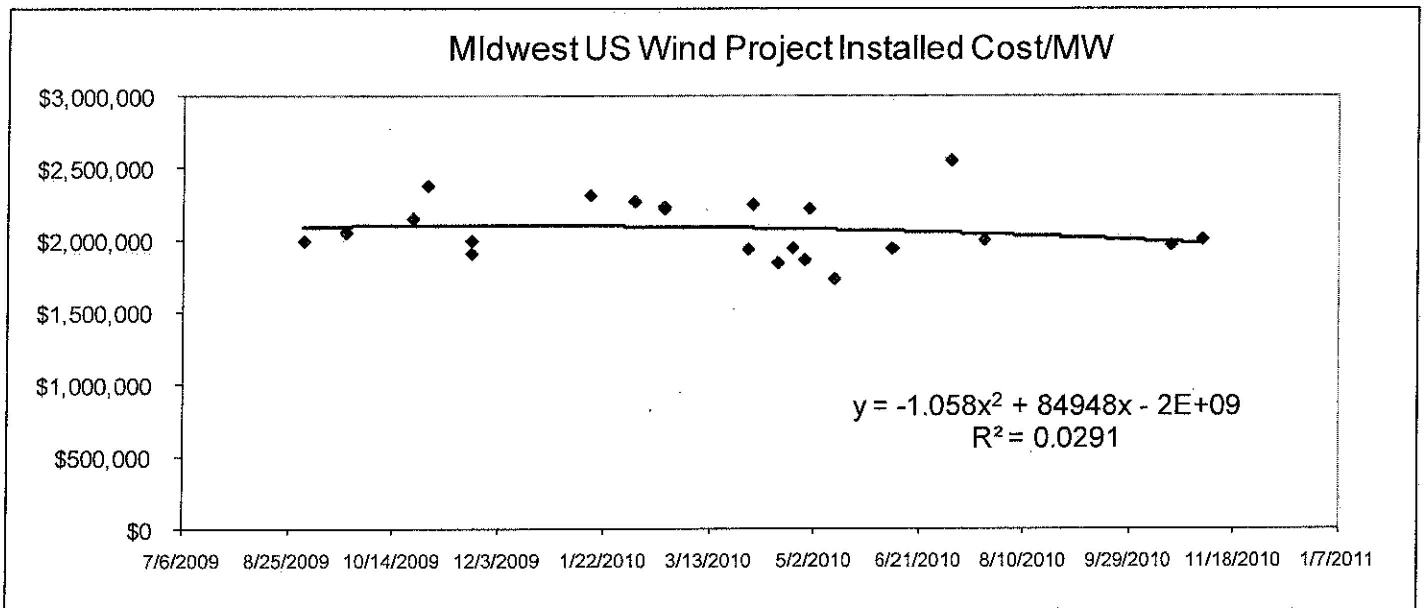
Using this data from Appendix A we plotted below a polynomial 2nd order trend line to determine the cost per MW for each region of the US. The dataset may reflect higher prices than market as of Dec 2010 due to 1)Developers with frame agreements prior to 2009 when turbine prices were higher placing those turbines on projects in 2009 and 2010 2)A perverse ITC incentive that encourages an increase in capex by requiring turbine suppliers to bundle O/M contracts with the turbine supply.

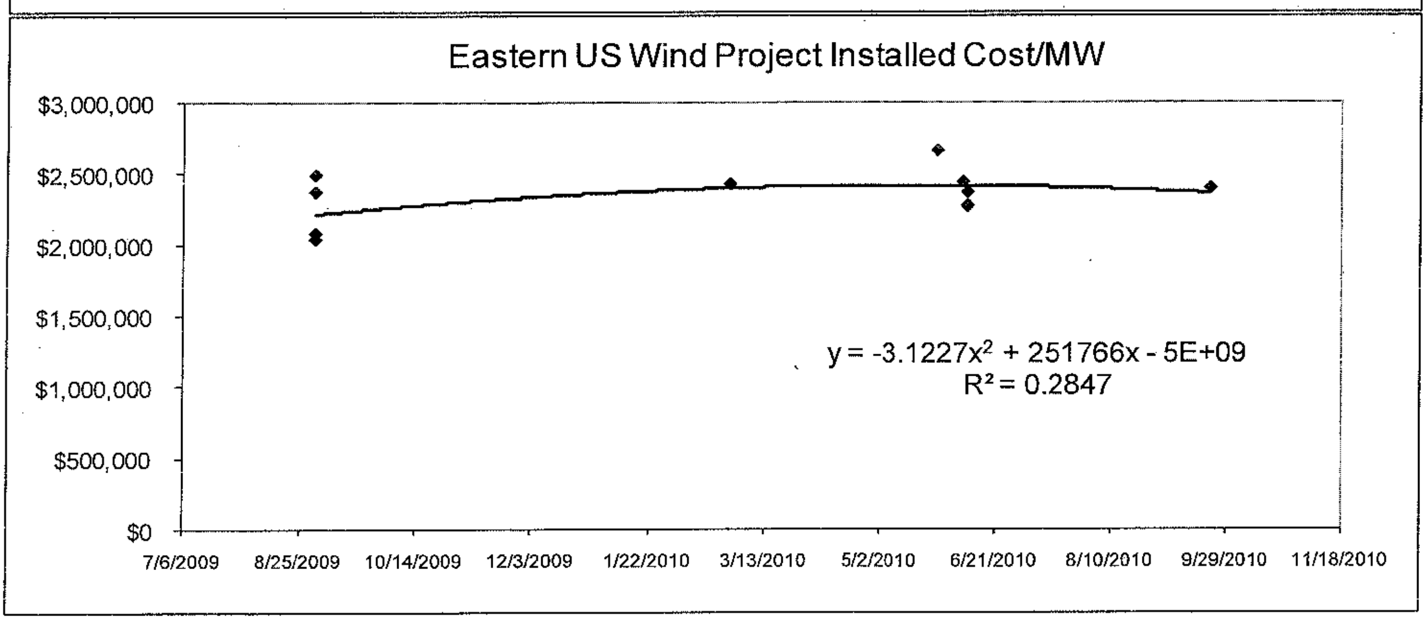
Looking at the Western US installed cost per MW graph below the trend line indicates turbine prices decreasing beginning in 2Q 2010 and ending at $1,893,430 per MW on July 30, 2010



Other regions are below as reference:


Texas Wind Project Installed Cost/MW
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
7/6/2009
8/25/2009
10/14/2009
12/3/2009
1/22/2010
3/13/2010
5/2/2010
6/21/2010
8/10/2010
9/29/2010
y = 0.3298x² - 26431x + 5E+08
R² = 0.0037


MIdwest US Wind Project Installed Cost/MW
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
7/6/2009
8/25/2009
10/14/2009
12/3/2009
1/22/2010
3/13/2010
5/2/2010
6/21/2010
8/10/2010
9/29/2010
11/18/2010
1/7/2011
y = -1.058x² + 84948x - 2E+09
R² = 0.0291


Eastern US Wind Project Installed Cost/MW
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
7/6/2009
8/25/2009
10/14/2009
12/3/2009
1/22/2010
3/13/2010
5/2/2010
6/21/2010
8/10/2010
9/29/2010
11/18/2010
y = -3.1227x² + 251766x - 5E+09
R² = 0.2847

Appendix A: ITC Grant Recipients - Capex for US Wind Farms

ITC Grant % of Eligible CAPEX	30.00%	**By Region**
CAPEX % Eligible for ITC Grant	95.00%	**As of Nov. 3, 2010**
Min. Project Size $	$17,000,000	

Business	Property Location	Region	Property Type	Amount Awarded	Award Date	Project Size	CapEx			
							5 Year MACRS	Other	Total	Cost/MW
Evergreen Wind Power V, LLC	Maine	East	Wind	$40,441,471	9/1/2009	57.0 MW	$134,804,903	$7,094,995	$141,899,898	$2,489,472
Stetson Wind II, LLC	Maine	East	Wind	$19,328,865	5/27/2010	25.5 MW	$64,429,550	$3,391,029	$67,820,579	$2,659,631
Canandaigua Power Partners II, LLC	New York	East	Wind	$22,296,494	9/1/2009	37.6 MW	$74,321,647	$3,911,666	$78,233,312	$2,078,775
Canandaigua Power Partners, LLC	New York	East	Wind	$52,352,334	9/1/2009	88.4 MW	$174,507,780	$9,184,620	$183,692,400	$2,078,775
Noble Wethersfield Windpark, LLC	New York	East	Wind	$81,776,684	6/9/2010	126.0 MW	$272,588,947	$14,346,787	$286,935,733	$2,277,268
Noble Chateaugay Windpark, LLC	New York	East	Wind	$71,840,780	6/9/2010	106.5 MW	$239,469,267	$12,603,646	$252,072,912	$2,366,882
Noble Altona Windpark, LLC	New York	East	Wind	$67,804,589	6/7/2010	97.5 MW	$226,015,297	$11,895,542	$237,910,839	$2,440,111
Locust Ridge II, LLC	Pennsylvania	East	Wind	$59,162,064	9/1/2009	102.0 MW	$197,206,880	$10,379,309	$207,586,189	$2,035,159
Stony Creek Wind Farm, LLC	Pennsylvania	East	Wind	$33,918,368	6/9/2010	52.5 MW	$113,061,227	$5,950,591	$119,011,818	$2,266,892
Krayn Wind LLC	Pennsylvania	East	Wind	$42,204,562	9/1/2009	62.5 MW	$140,681,873	$7,404,309	$148,086,182	$2,369,379
AES Armenia Mountain Wind, LLC	Pennsylvania	East	Wind	$69,460,892	2/26/2010	100.5 MW	$231,536,307	$12,186,121	$243,722,428	$2,425,099
Beech Ridge Energy LLC	West Virginia	East	Wind	$68,609,459	9/22/2010	100.5 MW	$228,698,197	$12,036,747	$240,734,944	$2,395,373
Blackstone Wind Farm, LLC	Illinois	Midwest	Wind	$55,202,420	11/20/2009	102.0 MW	$184,008,067	$9,684,635	$193,692,702	$1,898,948
Streator-Cayuga Ridge Wind	Illinois	Midwest	Wind	$170,115,870	7/22/2010	300.0 MW	$567,052,900	$29,844,889	$596,897,789	$1,989,659
Rail Splitter Wind Farm, LLC	Illinois	Midwest	Wind	$61,447,344	10/23/2009	100.5 MW	$204,824,480	$10,780,236	$215,604,716	$2,145,321
Grand Ridge Energy IV LLC	Illinois	Midwest	Wind	$5,706,907	4/29/2010	9.1 MW	$19,023,023	$1,001,212	$20,024,235	$2,210,582
Grand Ridge Energy III LLC	Illinois	Midwest	Wind	$32,094,053	2/19/2010	50.9 MW	$106,980,177	$5,630,536	$112,610,712	$2,210,582
Grand Ridge Energy II LLC	Illinois	Midwest	Wind	$32,300,165	2/19/2010	51.0 MW	$107,667,217	$5,666,696	$113,333,912	$2,222,234
FPL Energy Illinois Wind, LLC	Illinois	Midwest	Wind	$138,854,047	4/2/2010	217.5 MW	$462,846,823	$24,360,359	$487,207,182	$2,240,033
EcoGrove Wind LLC	Illinois	Midwest	Wind	$67,868,807	10/30/2009	100.5 MW	$226,229,357	$11,906,808	$238,136,165	$2,369,514
Meadow Lake Wind Farm II LLC	Indiana	Midwest	Wind	$55,212,505	10/19/2010	99.0 MW	$184,041,683	$9,686,404	$193,728,088	$1,956,849
Meadow Lake Wind Farm LLC	Indiana	Midwest	Wind	$113,181,518	11/20/2009	199.7 MW	$377,271,727	$19,856,407	$397,128,133	$1,989,122
Meadow Lake Wind Farm III LLC	Indiana	Midwest	Wind	$58,886,968	11/3/2010	103.5 MW	$196,289,893	$10,331,047	$206,620,940	$1,996,338
Hoosier Wind Project,LLC	Indiana	Midwest	Wind	$69,555,205	1/15/2010	106.0 MW	$231,850,683	$12,202,668	$244,053,351	$2,302,390
Garden Wind, LLC	Iowa	Midwest	Wind	$83,576,778	4/14/2010	160.0 MW	$278,589,260	$14,662,593	$293,251,853	$1,832,824
Crystal Lake Wind III, LLC	Iowa	Midwest	Wind	$36,267,267	3/31/2010	66.0 MW	$120,890,890	$6,362,678	$127,253,568	$1,928,084
Lost Lakes Wind Farm LLC	Iowa	Midwest	Wind	$55,544,888	4/21/2010	100.7 MW	$185,149,627	$9,744,717	$194,894,344	$1,936,357
Barton Windpower LLC	Iowa	Midwest	Wind	$93,419,883	9/21/2009	160.0 MW	$311,399,610	$16,389,453	$327,789,063	$2,048,682
Heritage Stoney Corners	Michigan	Midwest	Wind	$9,016,266	2/5/2010	14.0 MW	$30,054,220	$1,581,801	$31,636,021	$2,259,716
Moraine Wind II LLC	Minnesota	Midwest	Wind	$28,019,520	9/1/2009	49.5 MW	$93,398,400	$4,915,705	$98,314,105	$1,986,144
Farmers City Wind, LLC	Missouri	Midwest	Wind	$84,959,857	9/21/2009	146.0 MW	$283,199,523	$14,905,238	$298,104,761	$2,041,813
Lost Creek Wind, LLC	Missouri	Midwest	Wind	$107,685,043	7/6/2010	148.5 MW	$358,950,143	$18,892,113	$377,842,256	$2,544,392
Rugby Wind LLC	North Dakota	Midwest	Wind	$73,094,236	5/11/2010	149.0 MW	$243,647,453	$12,823,550	$256,471,004	$1,721,282
Otter Tail Power Company	North Dakota	Midwest	Wind	$30,182,104	10/23/2009	49.5 MW	$100,607,013	$5,295,106	$105,902,119	$2,139,437
Elk City Wind	Oklahoma	Midwest	Wind	$52,254,333	4/27/2010	98.9 MW	$174,181,110	$9,167,427	$183,348,537	$1,853,878
Day County Wind, LLC	South Dakota	Midwest	Wind	$54,518,743	6/8/2010	99.0 MW	$181,729,143	$9,564,692	$191,293,835	$1,932,261
Inadale Wind Farm, LLC	Texas	Texas	Wind	$94,163,024	1/25/2010	197.0 MW	$313,876,747	$16,519,829	$330,396,575	$1,677,140
Panther Creek Wind Farm, LLC	Texas	Texas	Wind	$107,636,863	1/8/2010	199.5 MW	$358,789,543	$18,883,660	$377,673,204	$1,893,099
Penascal II Wind Project LLC	Texas	Texas	Wind	$108,789,503	7/30/2010	201.6 MW	$362,631,677	$19,085,878	$381,717,554	$1,893,440
Goat Wind, LP	Texas	Texas	Wind	$38,499,056	4/7/2010	69.6 MW	$128,330,187	$6,754,220	$135,084,407	$1,940,868
Langford Wind Power, LLC	Texas	Texas	Wind	$84,201,645	5/24/2010	150.0 MW	$280,672,150	$14,772,218	$295,444,368	$1,969,629
Penascal Wind Power LLC	Texas	Texas	Wind	$114,071,646	9/1/2009	201.6 MW	$380,238,820	$20,012,569	$400,251,389	$1,985,374
South Trent Wind LLC	Texas	Texas	Wind	$59,494,413	5/6/2010	101.2 MW	$198,314,710	$10,437,616	$208,752,326	$2,062,770
Notrees Windpower LP	Texas	Texas	Wind	$90,354,625	6/8/2010	152.6 MW	$301,182,083	$15,851,689	$317,033,772	$2,077,412
Barton Chapel Wind, LLC	Texas	Texas	Wind	$72,573,627	9/21/2009	120.0 MW	$241,912,090	$12,732,215	$254,644,305	$2,122,036
EON Climate & Renewables	Texas	Texas	Wind	$121,903,306	9/21/2009	199.5 MW	$406,344,353	$21,386,545	$427,730,898	$2,144,015
Pattern Gulf Wind Holdings LLC	Texas	Texas	Wind	$178,004,264	12/23/2009	283.2 MW	$593,347,547	$31,228,818	$624,576,365	$2,205,425
Loraine Windpark Project, LLC	Texas	Texas	Wind	$63,219,787	5/26/2010	100.5 MW	$210,732,623	$11,091,191	$221,823,814	$2,207,202
EC&R Papalote Creek I, LLC	Texas	Texas	Wind	$116,784,666	6/24/2010	179.9 MW	$389,282,220	$20,488,538	$409,770,758	$2,278,403
Sunray Wind LLC	Texas	Texas	Wind	$26,246,825	12/4/2009	39.0 MW	$87,489,417	$4,604,706	$92,094,123	$2,361,388
Bull Creek Wind LLC	Texas	Texas	Wind	$91,390,497	9/21/2009	180.0 MW	$304,634,990	$16,033,421	$320,668,411	$1,781,491

Dry Lake Wind Power LLC	Arizona	West	Wind	$31,345,799	11/20/2009	63.0 MW	$104,485,997	$5,499,263	$109,985,260	$1,745,798
Northern Colorado Wind Energy, LLC	Colorado	West	Wind	$99,900,326	11/20/2009	174.3 MW	$333,001,087	$17,526,373	$350,527,460	$2,011,058
Benentt Creek Windfarm, LLC	Idaho	West	Wind	$9,762,704	6/21/2010	21.0 MW	$32,542,347	$1,712,755	$34,255,102	$1,631,195
Hot Springs Windfarm, LLC	Idaho	West	Wind	$9,767,356	6/22/2010	21.0 MW	$32,557,853	$1,713,571	$34,271,425	$1,631,973
Cassia Wind Farm LLC	Idaho	West	Wind	$5,123,426	1/29/2010	10.5 MW	$17,078,087	$898,847	$17,976,933	$1,710,946
Cassia Gulch Wind Park LLC	Idaho	West	Wind	$9,212,592	1/29/2010	18.9 MW	$30,708,640	$1,616,244	$32,324,884	$1,710,946
Tuana Springs Energy, LLC	Idaho	West	Wind	$8,467,825	7/15/2010	16.8 MW	$28,226,083	$1,485,583	$29,711,667	$1,768,552
NaturEner Glacier Wind Energy 2, LLC	Montana	West	Wind	$62,249,825	11/20/2009	103.5 MW	$207,499,417	$10,921,022	$218,420,439	$2,110,342
High Lonesome Mesa, LLC	New Mexico	West	Wind	$53,632,975	4/21/2010	100.0 MW	$178,776,583	$9,409,294	$188,185,877	$1,881,859
Hay Canyon Wind LLC	Oregon	West	Wind	$47,092,555	9/1/2009	100.8 MW	$156,975,183	$8,261,852	$165,237,035	$1,639,256
Star Point Wind Project LLC	Oregon	West	Wind	$46,454,062	6/7/2010	98.7 MW	$154,846,873	$8,149,835	$162,996,709	$1,651,436
Pebble Springs Wind LLC	Oregon	West	Wind	$46,543,219	9/1/2009	98.7 MW	$155,144,063	$8,165,477	$163,309,540	$1,654,605
Wheat Field Wind Power Project LLC	Oregon	West	Wind	$47,717,155	9/1/2009	96.6 MW	$159,057,183	$8,371,431	$167,428,614	$1,733,215
FPL Energy Stateline II, Inc	Oregon	West	Wind	$55,386,898	1/25/2010	98.9 MW	$184,622,993	$9,717,000	$194,339,993	$1,965,015
Butter Creek Power, LLC	Oregon	West	Wind	$3,216,739	5/11/2010	5.0 MW	$10,722,463	$564,340	$11,286,804	$2,166,154
Wagon Trail, LLC	Oregon	West	Wind	$2,144,682	5/5/2010	3.3 MW	$7,148,940	$376,260	$7,525,200	$2,166,345
Ward Butte Windfarm, LLC	Oregon	West	Wind	$4,304,774	5/5/2010	6.6 MW	$14,349,247	$755,224	$15,104,470	$2,174,128
Eurus Combine Hills II LLC	Oregon	West	Wind	$39,133,973	6/7/2010	63.0 MW	$130,446,577	$6,865,609	$137,312,186	$2,179,559
Oregon Trail Windfarm, LLC	Oregon	West	Wind	$6,388,002	5/5/2010	9.9 MW	$21,293,340	$1,120,702	$22,414,042	$2,264,045
Sand Ranch Windfarm, LLC	Oregon	West	Wind	$6,393,713	5/5/2010	9.9 MW	$21,312,377	$1,121,704	$22,434,081	$2,266,069
Pacific Canyon Windfarm, LLC	Oregon	West	Wind	$5,338,964	5/5/2010	8.3 MW	$17,796,547	$936,660	$18,733,207	$2,270,692
Big Top, LLC	Oregon	West	Wind	$1,073,733	5/5/2010	1.7 MW	$3,579,110	$188,374	$3,767,484	$2,283,324
Four Mile Canyon Windfarm, LLC	Oregon	West	Wind	$6,766,453	5/5/2010	10.0 MW	$22,554,843	$1,187,097	$23,741,940	$2,374,194
Four Corners Windfarm, LLC	Oregon	West	Wind	$7,124,870	5/5/2010	10.0 MW	$23,749,567	$1,249,977	$24,999,544	$2,499,954
Threemile Canyon Wind I, LLC	Oregon	West	Wind	$7,252,653	4/6/2010	9.9 MW	$24,175,510	$1,272,395	$25,447,905	$2,570,495
Milford Wind Corridor Phase I, LLC	Utah	West	Wind	$120,147,810	3/10/2010	203.5 MW	$400,492,700	$21,078,563	$421,571,263	$2,071,603
Windy Flats Partners, LLC	Washington	West	Wind	$218,482,326	6/2/2010	398.8 MW	$728,274,420	$38,330,233	$766,604,653	$1,922,278
Harvest Wind	Washington	West	Wind	$60,755,706	4/2/2010	98.9 MW	$202,519,020	$10,658,896	$213,177,916	$2,155,490
Puget Sound Energy, Inc.	Washington	West	Wind	$28,674,664	2/19/2010	44.0 MW	$95,582,213	$5,030,643	$100,612,856	$2,286,656

ITC Grant Recipents
Estimated CAPEX for U.S. Wind Farms
Assumptions

ITC Grant % of Eligible CAPEX	30.00%		**By Region**
CAPEX % Eligible for ITC Grant	95.00%		**As of Nov. 3, 2010**
Min. Project Size $	$17,000,000		

Business	Property Location	Region	Property Type	Amount Awarded	Award Date	Project Size	CapEx 5 Year MACRS	CapEx Other	CapEx Total	Cost/MW
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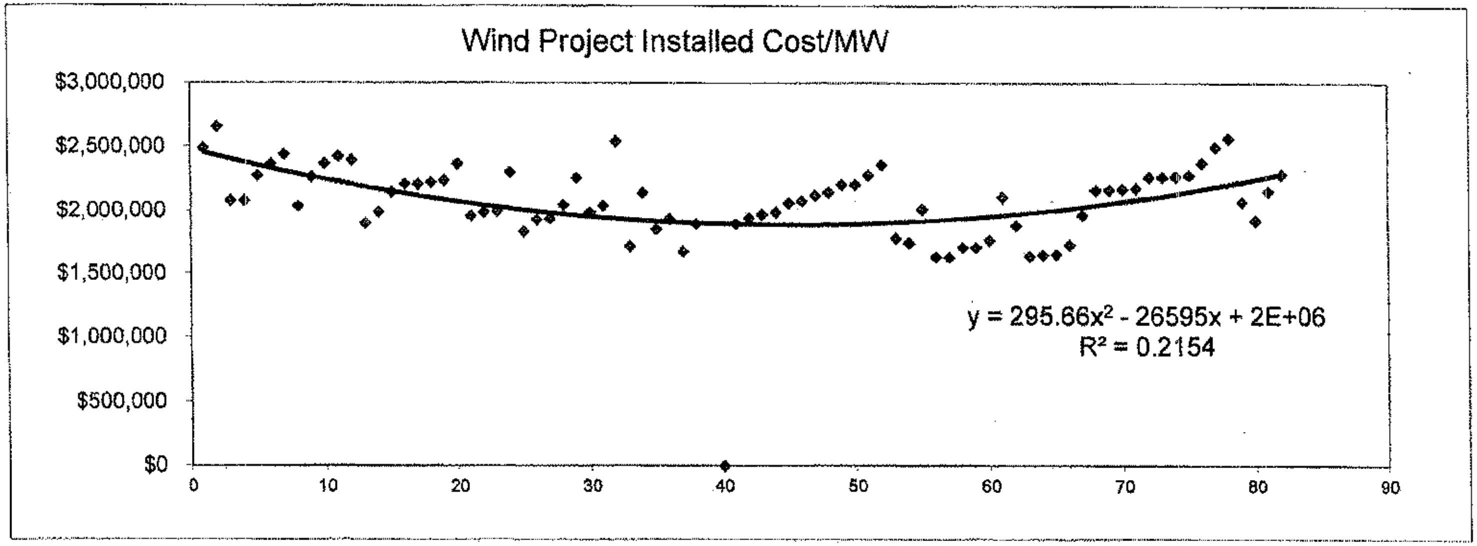
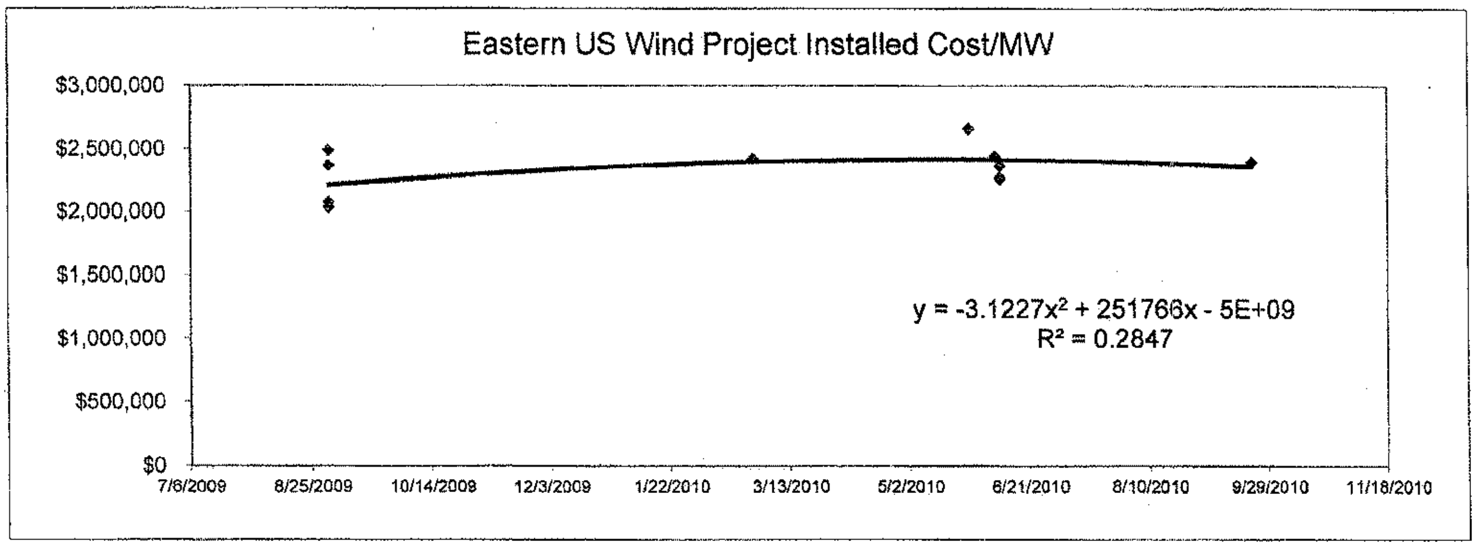
Garden Wind, LLC	Iowa	Midwest	Wind	$83,576,778	4/14/2010	160.0 MW	$278,589,260	$14,662,593	$293,251,853	$1,832,824
Crystal Lake Wind III, LLC	Iowa	Midwest	Wind	$36,267,267	3/31/2010	66.0 MW	$120,890,890	$6,362,678	$127,253,568	$1,928,084
Lost Lakes Wind Farm LLC	Iowa	Midwest	Wind	$55,544,888	4/21/2010	100.7 MW	$185,149,627	$9,744,717	$194,894,344	$1,936,357
Barton Windpower LLC	Iowa	Midwest	Wind	$93,419,883	9/21/2009	160.0 MW	$311,399,610	$16,389,453	$327,789,063	$2,048,682
Heritage Stoney Corners	Michigan	Midwest	Wind	$9,016,266	2/5/2010	14.0 MW	$30,054,220	$1,581,801	$31,636,021	$2,259,716
Moraine Wind II LLC	Minnesota	Midwest	Wind	$28,019,520	9/1/2009	49.5 MW	$93,398,400	$4,915,705	$98,314,105	$1,986,144
Farmers City Wind, LLC	Missouri	Midwest	Wind	$84,959,857	9/21/2009	146.0 MW	$283,199,523	$14,905,238	$298,104,761	$2,041,813
Lost Creek Wind, LLC	Missouri	Midwest	Wind	$107,685,043	7/6/2010	148.5 MW	$358,950,143	$18,892,113	$377,842,256	$2,544,392
Rugby Wind LLC	North Dakota	Midwest	Wind	$73,094,236	5/11/2010	149.0 MW	$243,647,453	$12,823,550	$256,471,004	$1,721,282
Otter Tail Power Company	North Dakota	Midwest	Wind	$30,182,104	10/23/2009	49.5 MW	$100,607,013	$5,295,106	$105,902,119	$2,139,437
Elk City Wind	Oklahoma	Midwest	Wind	$52,254,333	4/27/2010	98.9 MW	$174,181,110	$9,167,427	$183,348,537	$1,853,878
Day County Wind, LLC	South Dakota	Midwest	Wind	$54,518,743	6/8/2010	99.0 MW	$181,729,143	$9,564,692	$191,293,835	$1,932,261
Inadale Wind Farm, LLC	Texas	Texas	Wind	$94,163,024	1/25/2010	197.0 MW	$313,876,747	$16,519,829	$330,396,575	$1,677,140
Panther Creek Wind Farm, LLC	Texas	Texas	Wind	$107,636,863	1/8/2010	199.5 MW	$358,789,543	$18,883,660	$377,673,204	$1,893,099

Business	Property Location	Region	Property Type	Amount Awarded	Award Date	Project Size	CapEx 5 Year MACRS	CapEx Other	CapEx Total	Cost/MW
Penascal II Wind Project LLC	Texas	Texas	Wind	$108,789,503	7/30/2010	201.6 MW	$362,631,677	$19,085,878	$381,717,554	$1,893,440
Goat Wind, LP	Texas	Texas	Wind	$38,499,056	4/7/2010	69.6 MW	$128,330,187	$6,754,220	$135,084,407	$1,940,868
Langford Wind Power, LLC	Texas	Texas	Wind	$84,201,645	5/24/2010	150.0 MW	$280,672,150	$14,772,218	$295,444,368	$1,969,629
Penascal Wind Power LLC	Texas	Texas	Wind	$114,071,646	9/1/2009	201.6 MW	$380,238,820	$20,012,569	$400,251,389	$1,985,374
South Trent Wind LLC	Texas	Texas	Wind	$59,494,413	5/6/2010	101.2 MW	$198,314,710	$10,437,616	$208,752,326	$2,062,770
Notrees Windpower LP	Texas	Texas	Wind	$90,354,625	6/8/2010	152.6 MW	$301,182,083	$15,851,689	$317,033,772	$2,077,412
Barton Chapel Wind, LLC	Texas	Texas	Wind	$72,573,627	9/21/2009	120.0 MW	$241,912,090	$12,732,215	$254,644,305	$2,122,036
E.ON Climate & Renewables	Texas	Texas	Wind	$121,903,306	9/21/2009	199.5 MW	$406,344,353	$21,386,545	$427,730,898	$2,144,015
Pattern Gulf Wind Holdings LLC	Texas	Texas	Wind	$178,004,264	12/23/2009	283.2 MW	$593,347,547	$31,228,818	$624,576,365	$2,205,425
Loraine Windpark Project, LLC	Texas	Texas	Wind	$63,219,787	5/26/2010	100.5 MW	$210,732,623	$11,091,191	$221,823,814	$2,207,202
EC&R Papalote Creek I, LLC	Texas	Texas	Wind	$116,784,666	6/24/2010	179.9 MW	$389,282,220	$20,488,538	$409,770,758	$2,278,403
Sunray Wind LLC	Texas	Texas	Wind	$26,246,825	12/4/2009	39.0 MW	$87,489,417	$4,604,706	$92,094,123	$2,361,388
Bull Creek Wind LLC	Texas	Texas	Wind	$91,390,497	9/21/2009	180.0 MW	$304,634,990	$16,033,421	$320,668,411	$1,781,491
Dry Lake Wind Power LLC	Arizona	West	Wind	$31,345,799	11/20/2009	63.0 MW	$104,485,997	$5,499,263	$109,985,260	$1,745,798
Northern Colorado Wind Energy, LLC	Colorado	West	Wind	$99,900,326	11/20/2009	174.3 MW	$333,001,087	$17,526,373	$350,527,460	$2,011,058
Benentt Creek Windfarm, LLC	Idaho	West	Wind	$9,762,704	6/21/2010	21.0 MW	$32,542,347	$1,712,755	$34,255,102	$1,631,195
Hot Springs Windfarm, LLC	Idaho	West	Wind	$9,767,356	6/22/2010	21.0 MW	$32,557,853	$1,713,571	$34,271,425	$1,631,973
Cassia Wind Farm LLC	Idaho	West	Wind	$5,123,426	1/29/2010	10.5 MW	$17,078,087	$898,847	$17,976,933	$1,710,946
Cassia Gulch Wind Park LLC	Idaho	West	Wind	$9,212,592	1/29/2010	18.9 MW	$30,708,640	$1,616,244	$32,324,884	$1,710,946
Tuana Springs Energy, LLC	Idaho	West	Wind	$8,467,825	7/15/2010	16.8 MW	$28,226,083	$1,485,583	$29,711,667	$1,768,552
NaturEner Glacier Wind Energy 2, LLC	Montana	West	Wind	$62,249,825	11/20/2009	103.5 MW	$207,499,417	$10,921,022	$218,420,439	$2,110,342
High Lonesome Mesa, LLC	New Mexico	West	Wind	$53,632,975	4/21/2010	100.0 MW	$178,776,583	$9,409,294	$188,185,877	$1,881,859
Hay Canyon Wind LLC	Oregon	West	Wind	$47,092,555	9/1/2009	100.8 MW	$156,975,183	$8,261,852	$165,237,035	$1,639,256
Star Point Wind Project LLC	Oregon	West	Wind	$46,454,062	6/7/2010	98.7 MW	$154,846,873	$8,149,835	$162,996,709	$1,651,436
Pebble Springs Wind LLC	Oregon	West	Wind	$46,543,219	9/1/2009	98.7 MW	$155,144,063	$8,165,477	$163,309,540	$1,654,605
Wheat Field Wind Power Project LLC	Oregon	West	Wind	$47,717,155	9/1/2009	96.6 MW	$159,057,183	$8,371,431	$167,428,614	$1,733,215
FPL Energy Stateline II, Inc	Oregon	West	Wind	$55,386,898	1/25/2010	98.9 MW	$184,622,993	$9,717,000	$194,339,993	$1,965,015
Butter Creek Power, LLC	Oregon	West	Wind	$3,216,739	5/11/2010	5.0 MW	$10,722,463	$564,340	$11,286,804	$2,166,154
Wagon Trail, LLC	Oregon	West	Wind	$2,144,682	5/5/2010	3.3 MW	$7,148,940	$376,260	$7,525,200	$2,166,345
Ward Butte Windfarm, LLC	Oregon	West	Wind	$4,304,774	5/5/2010	6.6 MW	$14,349,247	$755,224	$15,104,470	$2,174,128
Eurus Combine Hills II LLC	Oregon	West	Wind	$39,133,973	6/7/2010	63.0 MW	$130,446,577	$6,865,609	$137,312,186	$2,179,559
Oregon Trail Windfarm, LLC	Oregon	West	Wind	$6,388,002	5/5/2010	9.9 MW	$21,293,340	$1,120,702	$22,414,042	$2,264,045
Sand Ranch Windfarm, LLC	Oregon	West	Wind	$6,393,713	5/5/2010	9.9 MW	$21,312,377	$1,121,704	$22,434,081	$2,266,069
Pacific Canyon Windfarm, LLC	Oregon	West	Wind	$5,338,964	5/5/2010	8.3 MW	$17,796,547	$936,660	$18,733,207	$2,270,692
Big Top, LLC	Oregon	West	Wind	$1,073,733	5/5/2010	1.7 MW	$3,579,110	$188,374	$3,767,484	$2,283,324
Four Mile Canyon Windfarm, LLC	Oregon	West	Wind	$6,766,453	5/5/2010	10.0 MW	$22,554,843	$1,187,097	$23,741,940	$2,374,194
Four Corners Windfarm, LLC	Oregon	West	Wind	$7,124,870	5/5/2010	10.0 MW	$23,749,567	$1,249,977	$24,999,544	$2,499,954
Threemile Canyon Wind I, LLC	Oregon	West	Wind	$7,252,653	4/6/2010	9.9 MW	$24,175,510	$1,272,395	$25,447,905	$2,570,495
Milford Wind Corridor Phase I, LLC	Utah	West	Wind	$120,147,810	3/10/2010	203.5 MW	$400,492,700	$21,078,563	$421,571,263	$2,071,603
Windy Flats Partners, LLC	Washington	West	Wind	$218,482,326	6/2/2010	398.8 MW	$728,274,420	$38,330,233	$766,604,653	$1,922,278
Harvest Wind	Washington	West	Wind	$60,755,706	4/2/2010	98.9 MW	$202,519,020	$10,658,896	$213,177,916	$2,155,490
Puget Sound Energy, Inc.	Washington	West	Wind	$28,674,664	2/19/2010	44.0 MW	$95,582,213	$5,030,643	$100,612,856	$2,286,656
						Total	$15,384,502,717	$809,710,669	$16,194,213,386	


Wind Project Installed Cost/MW
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
0
10
20
30
40
50
60
70
80
90
y = 295.66x² - 26595x + 2E+06
R² = 0.2154


Eastern US Wind Project Installed Cost/MW
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$2,000,000
$1,500,000
$1,000,000
$500,000
$0
7/6/2009
8/25/2009
10/14/2009
12/3/2009
1/22/2010
3/13/2010
5/2/2010
6/21/2010
8/10/2010
9/29/2010
11/18/2010
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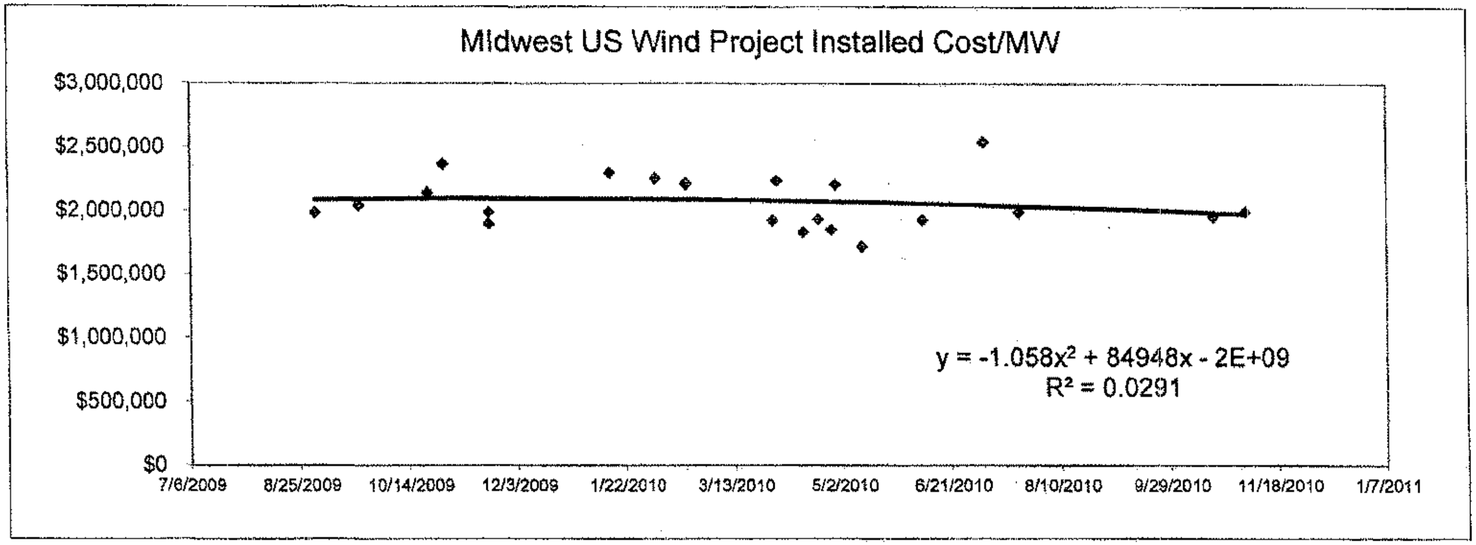
R² = 0.2847


Midwest US Wind Project Installed Cost/MW
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$2,000,000
$1,500,000
$1,000,000
$500,000
$0
7/6/2009
8/25/2009
10/14/2009
12/3/2009
1/22/2010
3/13/2010
5/2/2010
6/21/2010
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1/7/2011
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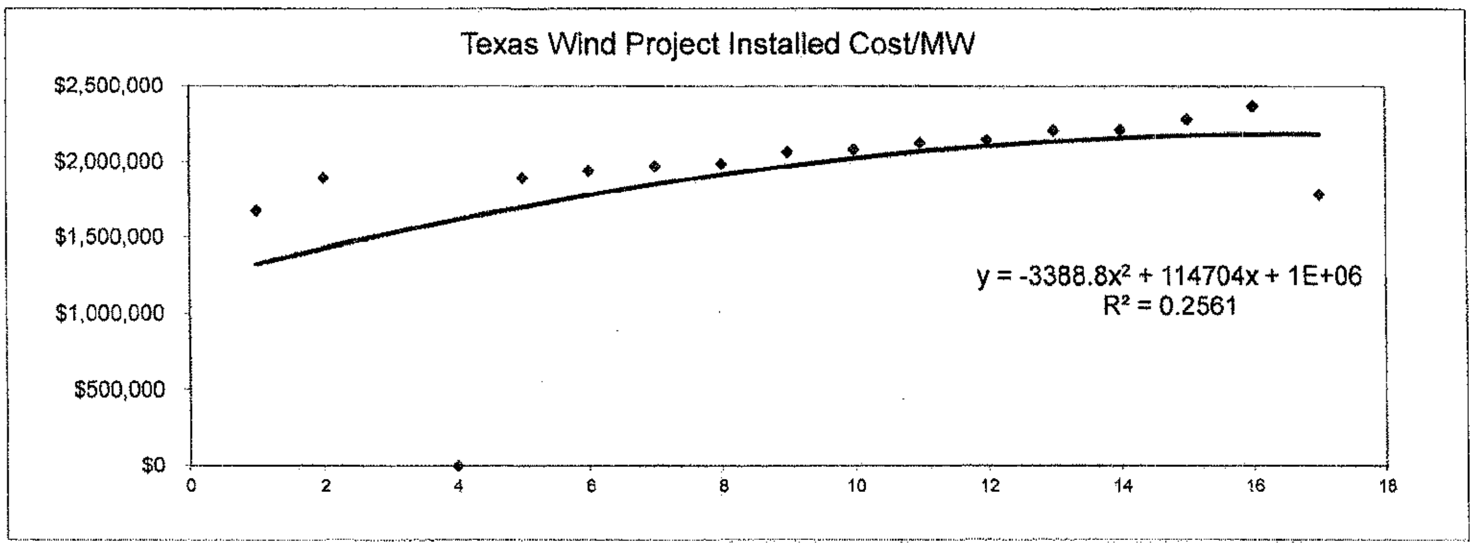
R² = 0.0291


Texas Wind Project Installed Cost/MW
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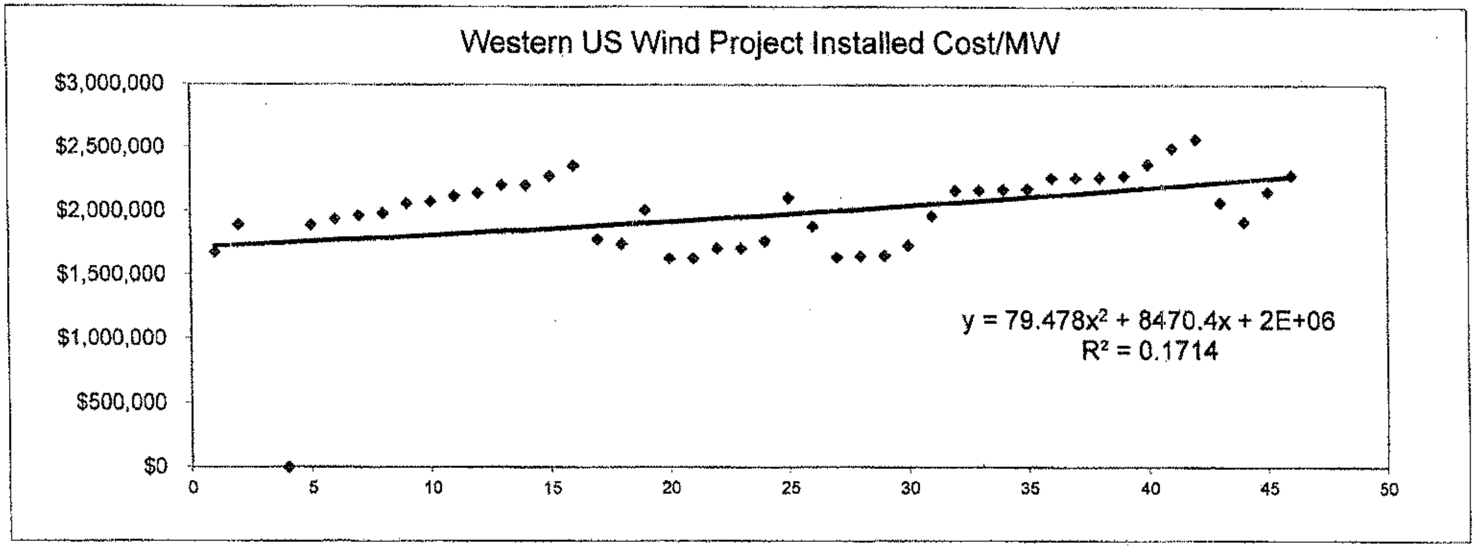
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
0
2
4
6
8
10
12
14
16
18
y = -3388.8x² + 114704x + 1E+06
R² = 0.2561


Western US Wind Project Installed Cost/MW
$3,000,000
$2,500,000
$2,000,000
$1,500,000
$1,000,000
$500,000
$0
0
5
10
15
20
25
30
35
40
45
50
y = 79.478x² + 8470.4x + 2E+06
R² = 0.1714

Schedule 2

Wyoming Capacity Factor Recommendations
For IRP modeling, we recommend that Pacificorp use a 43.6 percent or higher net capacity factor (NCF) for future Wyoming wind projects. One method Pacificorp should consider is the average of the predicted capacity factors and adjusted costs of the already built projects using more recent, next generation turbine performance and cost data.

GE 1.5 MW sle turbines where installed on all Pacificorp built sites from 2008 through 2010. The following chart illustrates the p50 capacity factor predicted for each of the sites according to various testimony in PUC dockets in Utah (10-035-23, 10-035-89) and in Oregon (UE200, 210).

Wind Projects Built by Pacificorp (2008 through 2010)				
Facility Name	MW	COD	NCF	Turbine Type
Glenrock Wind I	99	2008	37.40%	66 x 1.5MW x 77m rotor, GE SLE
Seven Mile Hill Wind	99	2008	41.00%	66 x 1.5MW x 77m rotor, GE SLE
Seven Mile Hill Wind II	19.5	2008	40.30%	66 x 1.5MW x 77m rotor, GE SLE
Glenrock Wind III	39	2009	36.4%	13 x 1.5MW x 77m rotor, GE SLE
Rolling Hills Wind	99	2009	33.80%	66 x 1.5MW x 77m rotor, GE SLE
High Plains	99	2009	35.30%	66 x 1.5MW x 77m rotor, GE SLE
McFadden Ridge	28.5	2009	34.50%	19 x 1.5MW x 77m rotor, GE SLE
Dunlap	111	2010	38.60%	74 x 1.5MW x 77m rotor, GE SLE
	Avg NCF with Rolling Hills		37.2%	
	Avg NCF without Rolling Hills		37.6%	

Table 1: NCFs of Wyoming Pacificorp Projects

We averaged the NCF with and without the Rolling Hills project to reflect the Oregon PUC disallowance of certain capital costs due to a lower than expected capacity factor. We did not average the capacity factors for projects in western Wyoming as those projects do not reflect the higher capacity factors experienced in the central Wyoming projects. Using the average NCF for existing Pacificorp projects is arguably a reasonable proxy for capacity factors if the GE SLE turbine were the most appropriate turbine going forward. However, this turbine has lower NCF than newer turbines now on the market (cost analyis is covered later). These advanced turbines with longer, more efficient blades for a given nameplate capacity came on the market in 2009 and are being supplied in commercial quantities to projects by established, credible suppliers. Therefore, we recommend the NCF be adjusted upward to reflect these advances as follows.

We selected the turbines in the below table for general wind suitability in Wyoming. To determine turbine potential improvements, in the below table we compared the NCF of three of the most prevalent "advanced" turbines with three "workhorse" turbines that have been supplied in the United States for several years. The advanced turbines have been erroniously classified by some as "low wind speed" turbines leading to inaccurate conclusions that they are not suitable in high wind speed areas. This generally is true at sea level but not at high altitude. In our experience, most sites above 7000 feet are suitable for these turbines as long as the average annual wind speeds do not exceed 9.3

m/s*. Increasing the 8.5 m/s sea level limit for Class 2 turbines is governed by the altitude derate ie. (alt density/sealevel density)^.33. We have found that many Wyoming sites also exhibit low turbulence and on a case by case basis the wind speed average upper limit can be even higher depending on turbine spacing and the wind rose. Competitive wind speeds in Wyoming generally average 8.5 to 9.5 m/s and while not definitive for the use of advanced turbine at all Wyoming sites, these turbines are suitable at most sites and should be modeled in the IRP. Of note, as further argument, GE has determined depending on final layouts and turbulence intensity that the xle model is meterologically suitable for some wind projects at 7500' altitiude with annual average wind speeds of 8.5 m/s to over 10 m/s.

		Turbine Class	Nameplate Size MW	Rotor Dia (m)	Rotor Area/ MW size	Relative Annual Energy Yield for indicated avg WS (7000' alt) 9 m/s	8 m/s	7 m/s
	GE 1.5 sle	2	1.5	77	3104	100%	100%	100%
Workhorse	Suzlon S88	2	2.1	88	2896	97%	96%	95%
	Clipper C96	2	2.5	96	2895	97%	96%	95%
	GE 1.5 xle	2b	1.5	82.5	3564	111%	114%	116.4%
Advanced	Vestas V90	2b	1.8	90	3534	110%	114%	115%
	Siemens 2.3	2b	2.3	101	3483	109%	112%	114%

*For normal turbulence, the advanced turbines are generally suitable for sea level sites with less than an annual avg wind speed limit of 8.5 m/s and somewhat higher for the workhorse turbines. At 7000 feet altitude, the limit can be increased to approximately 9.3 m/s and somewhat higher for lower turbulence intensity sites.

Table 2: Increase in Energy Yield using Advanced Turbines

Using the GE sle and xle power curves, we determined the increase in annual energy yield of the GE xle compared to the GE sle for a typical Wyoming wind distribution (Wiebull K=2) for three wind speeds. The capacity factor increase ranges from 111% to 116%. We ran Wk sensitivities of 1.8 to 2.2, which are the ranges of wind distributions in the NREL Western Wind and Solar Integration study for our random selection of commercially viable wind areas. The NCF increase for the advanced turbines across the expected Wk's and wind speeds was 111% to 118% (see table below).

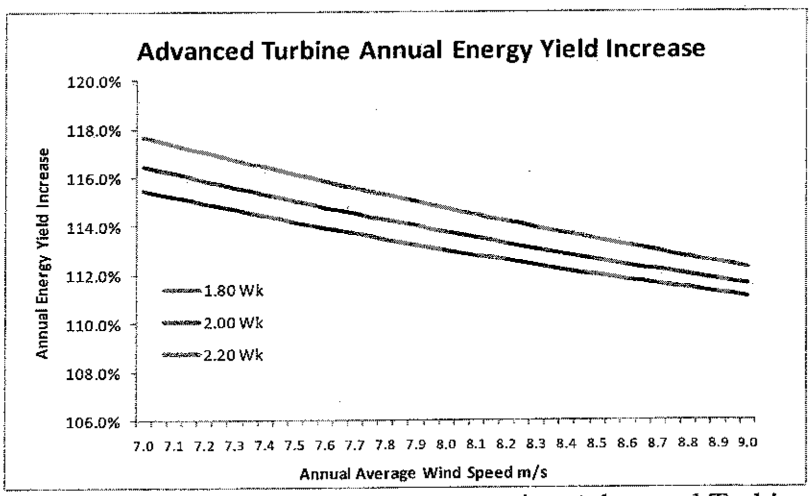


Chart 1: Energy Yield Improvement using Advanced Turbines

Back calculating from the average NCF at the Pacificorp projects, with a 15% gross to net energy loss, reveals annual wind speeds of 8.2 to 9.2 m/s. For this wind speed range and 1.8 to 2.2 Wk the range of NCF increases ranged from 111% to 114%. We recommend that a 8.6 m/s wind speed represents the average wind speed for the Pacificorp projects thus by selecting 112% and an expected minimum Wk of 1.8 from Chart 1 gives a minimum capacity factor for Wyoming as follows:

Using 37.6% NCF as the average from table 1
Adjusted NCF = 37.6% x 112% = 42.1%

Next, we wanted to determine the NCF improvement of other advanced turbines compared to the GE xle results. We compared the rotor area/mw size "rotor ratio" for each turbine and made scaling adjustments to match the power curves. Generally, the capacity factor change is directly proportional to the change in rotor ratio. Using this method, the Vestas V90-1.8 and the Siemens 2.3 improved the NCF by 109% to 115% greater than the GE sle and slightly lower than the GE xle. As expected, all three advanced turbines are in the same general range of performance improvement as all three turbines compete directly in the same markets. Therefore, for simplicity, we recommend using 112% NCF improvement for all three turbines over the older technology workhorse turbines. In summary, the evidence indicates a 42.1% NCF for Wyoming IRP modeling.

Also it could be argued that the capacity factor to model should be from the latest RFP benchmark (Dunlap) as this process reflects the most recent robust competitive environment. Consider the Testimony of Stefan A Bird, PacifiCorp, in Utah Public Service Commission Docket No. 10-035-89, Exhibit E, p. 11, lines 232-235 (citing Benchmark memo at p. 11-12): "Finally, the IE found that the estimated Benchmark capacity factor was within the range of capacity factors from proposals associated with potential resources in the nearby vicinity." Since the estimated capacity factor for Dunlap is 38.6% the adjusted NCF with the better turbines is:

Adjusted NCF = 38.6% x 112% = 43.2%

Utah Capacity Factor Recommendations

For IRP modeling, we recommend that Pacificorp use a 34 percent or higher net capacity factor (NCF) for future Utah wind projects up to 1,000 MW's. See Exhibit B. The was determined by using the same rationale as used above.

Appendix A

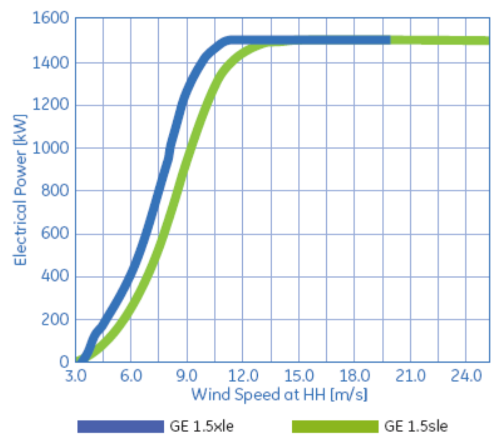
1.5 MW Wind Turbine Brochure;
http://www.gepower.com/prod_serv/products/wind_turbines/en/15mw/index.htm

[Alternate website] http://www.cems.uvm.edu/~phines/classes/ee113/2011-spring/ge-1.5MW-brochure.pdf

Technical data

Operating Data		1.5sle	1.5xle
Rated Capacity:		1,500 kW	1,500 kW
Temperature Range: (with Cold Weather Extreme Package)	Operation: Survival:	-30°C – +40°C -40°C – +50°C	-30°C – +40°C -40°C – +50°C
Cut-in Wind Speed:		3.5 m/s	3.5 m/s
Cut-out Wind Speed (10 min avg.):		25 m/s	20 m/s
Rated Wind Speed:		14 m/s	11.5 m/s
Wind Class — IEC:		IIa (V_{e50} = 55 m/s V_{ave} = 8.5 m/s)	IIIb (V_{e50} = 52.5 m/s V_{ave} = 8.0 m/s)
Electrical Interface			
Frequency		50/60 Hz	50/60 Hz
Voltage		690V	690V
Rotor			
Rotor Diameter:		77 m	82.5 m
Swept Area:		4657 m^2	5346 m^2
Tower			
Hub Heights:		65/80 m	80 m
Power Control		Active Blade Pitch Control	Active Blade Pitch Control

Power curve



http://site.ge-energy.com/prod_serv/products/wind_turbines/en/15mw/specs.htm

1.5 MW Wind Turbine Technical Specifications

1.5 MW Wind Turbine Technical Specifications

		TC3+			TC2		TCI
		1.5-82.5	**1.6-82.5**	**1.6-77**	**1.5-77**	**1.5-82.5**	**1.5-70**
Rotor Diameter	m	82.5	82.5	77	77	82.5	70.5
Hub Heights	M	80/100	80/100	80	64.7, 80	80	64.7
Frequency	Hz	50/60	60	50/60	50/60	60	60
	Vavg; m/s	8.0	8.0	8.0	8.5	8.5	10.0
	Vref; m/s	37.1	40.0	39.1	39.1	40.0	50.0
	Ve50; m/s	52.5	56.0	55.0	55.0	56.0	70.0
	Cut-In; m/s	3.5	3.5	3.5	3.5	3.5	4.0
	Cut-Out; m/s	20	25	25	25	25	25
	IEC Wind Class	IEC TC III+	IEC TC III+	IEC TC III+	IEC TC IIA	IEC TC IIB	IEC TC Ib

Appendix B

Summary of Utah WREZ Prospects

Ridge/Plateau/Valley Sites

Rich Simon data

Site Number	Name	County	Potential MW	Estimation Technique for MW*	Estimated Long-Term 80-m Speed (mps)	Gross CF at 1.01 Air Density	Elevation (ft)	GE-1.5sle Gross Cap. Factor (%)**
17	Blue Mtn Plateau	Uintah	150	4 x 15 RD	6.0	30.3	7800	28.8
49	Blakes Lambing Ground	Washington	70	6 MW/km	7.2	23.5	4500	24.1
1	Goose Creek Mtns	Box Elder	65	6 MW/km	7.4	23.5	8000	22.2
14	South Mtn	Tooele	80	5 MW/km,	7.1	28.3	5500	28.5
23	Ford Ridge	Carbon	200	6 MW/km	7.4	28.9	9000	26.6
48	Beaver Dam Mtns	Washington	60	5 MW/km	7.1	24.2	5900	24.1
35	Mineral Mtns	Beaver	100	5 MW/km	7.2	25.8	7700	24.6
31	Black Rock	Millard	200	4 x 15 RD,	7.0	30.7	5600	30.8
5	Clarkston Mtn	Box Elder/Cache	60	6 MW/km	7.1	34.3	7500	32.9
12	Lewis Peak	Morgan/Summit	140	6 MW/km	7.1	31.2	7500	29.9
22	Schofield	Utah/Carbon	60	6 MW/km	7.2	26.6	8500	24.8
46	Harmony Mtns	Iron	60	6 MW/km	7.0	24.2	7000	23.5
32	Milford North	Beaver/Millard	500	4 x 15 RD	6.8	29.3	5300	29.6
10	Porcupine Ridge	Summit	200	5 MW/km	6.9	32.0	7600	30.6
21	Wasatch Plateau	Sanpete/Utah	220	6 MW/km	7.0	28.0	9000	25.8
7	Crawford Mtn	Rich	150	6 MW/km	6.8	32.9	7500	31.5
8	Monte Cristo	Rich	180	4 MW/km	6.8	31.2	7600	29.8
29	Garrison	Millard	120	4 x 15 RD,	6.6	27.8	5700	27.8
41	Torrey	Wayne	50	see remarks	6.7	26.3	6800	25.6
47	Pintura	Washington	100	4 x 15 RD	6.5	28.9	4600	29.6
33	Wah Wah Valley	Beaver/Millard	500	4 x 15 RD	6.5	28.5	5100	28.9
50	Sand Mtn	Washington	70	4-5 MW/km	6.4	21.4	3800	22.4
28	Horse Point Ridge	Grand/Uintah	250	5 MW/km	6.7	27.1	8100	25.6
11	Morgan Ridge	Morgan/Summit	50	5 MW/km	6.6	32.9	7200	31.7
19	Eureka	Utah/Juab/Tooele	200	4-5 MW/km	6.6	28.8	7300	27.7
25	Bad Land Cliffs	Duchesne	180	5 MW/km,	6.7	28.0	8500	26.1
30	Sevier Desert	Millard	500	4 x 15 RD	6.4	28.5	4800	29.1
36	Black Mtns	Beaver/Iron	160	5 MW/km	6.5	24.7	5800	24.6
6	Junction Hills	Box Elder/Cache	70	5 MW/km	6.4	30.0	5600	30.1
9	Murphy Ridge	Rich	75	5 MW/km	6.5	32.0	7000	31.1
44	Monticello	San Juan	500	4 x 15 RD	6.5	26.0	7000	25.2
27	Hill Creek Extension	Uintah/Grand	250	4-5 MW/km	6.6	26.3	8300	24.7
37	Chipman Peak	Beaver/Iron	200	6 MW/km,	6.5	24.7	7600	23.6
40	Parker-Loa	Wayne/Piute/Sevier	250	4 x 15 RD	6.6	26.3	8500	24.6
45	Enterprise	Iron	230	6 MW/km	6.3	25.5	5600	25.6
2	Cedar Creek	Box Elder	250	4 x 15 RD	6.2	33.7	5000	34.3
34	Milford South	Beaver	500	4 x 15 RD	6.2	29.3	5000	29.8
20	Dog Valley	Utah/Juab	120	5 MW/km	6.3	27.1	6600	26.6
24	Argyle Ridge	Duchesne/Carbon	140	5 MW/km	6.5	28.0	9000	25.8
39	Burrville Pass	Sevier	140	4-6 MW/km,	6.4	25.1	7700	23.9
4	Point Lookout	Box Elder	50	5 MW/km	6.2	32.0	6300	31.6
16	Diamond Mtn	Uintah	150	5 MW/km,	6.3	30.3	7500	29.1
18	Boulter Summit	Tooele/Juab	100	4 x 15 RD	6.2	25.9	6200	25.6
26	Cedar Mtn	Emery	250	5 MW/km,	6.3	29.5	7200	28.4
15	Clay Hollow	Salt Lake	80	4 x 15 RD,	6.1	32.2	5200	32.7
42	Stevens Mesa	Wayne/Garfield	110	6 MW/km	6.1	26.0	5900	25.9
51	Little Creek Mtn	Washington	160	4 x 15 RD	6.1	23.4	5700	23.5
38	Antelope Range	Sevier/Piute	120	5 MW/km	6.1	25.5	7000	24.7
3	West Hills	Box Elder	75	4 MW/km	6.0	34.5	6600	33.8
13	Grassy Mtn Gap	Tooele	250	4 x 15 RD	5.8	31.1	4500	32.0
43	St. Johns Valley	Garfield	400	4 x 15 RD,	6.0	26.3	7400	25.2
TOTAL			12945					

Wasatch Data using GE XLE Calcs Table

Lookup Alt Adj Effective WS m/s	Weibull k	Avg Temp F	Air Density	GCF at air dens.	Cum MW	NCF with 15% loss
5.99	2.0	38	0.96	#N/A		#N/A
7.49	2.0	38	1.08	42.4%	70	36.1%
7.36	2.0	38	0.95	41.6%	135	35.4%
7.29	2.0	38	1.04	41.1%	215	34.9%
7.27	2.0	38	0.91	40.9%	415	34.8%
7.25	2.0	38	1.03	40.8%	475	34.7%
7.19	2.0	38	0.96	40.4%	575	34.3%
7.18	2.0	38	1.04	40.2%	775	34.2%
7.11	2.0	38	0.97	36.4%	835	31.0%
7.11	2.0	38	0.97	36.4%	975	31.0%
7.12	2.0	38	0.93	36.4%	1035	31.0%
7.05	2.0	38	0.98	36.0%	1095	30.6%
7.00	2.0	38	1.05	35.6%	1595	30.2%
6.90	2.0	38	0.96	34.6%	1795	29.4%
6.88	2.0	38	0.91	34.2%	2015	29.1%
6.81	2.0	38	0.97	33.7%	2165	28.7%
6.80	2.0	38	0.96	33.7%	2345	28.7%
6.76	2.0	38	1.03	33.3%	2465	28.3%
6.77	2.0	38	0.99	33.3%	2515	28.3%
6.75	2.0	38	1.08	33.3%	2615	28.3%
6.71	2.0	38	1.06	32.8%	3115	27.9%
6.71	2.0	38	1.11	32.8%	3185	27.9%
6.66	2.0	38	0.94	32.4%	3435	27.5%
6.63	2.0	38	0.98	31.9%	3485	27.1%
6.63	2.0	38	0.97	31.9%	3685	27.1%
6.62	2.0	38	0.93	31.9%	3865	27.1%
6.63	2.0	38	1.07	31.9%	4365	27.1%
6.65	2.0	38	1.03	31.9%	4525	27.1%
6.56	2.0	38	1.04	31.4%	4595	26.7%
6.55	2.0	38	0.98	31.4%	4670	26.7%
6.55	2.0	38	0.98	31.4%	5170	26.7%
6.54	2.0	38	0.94	31.0%	5420	26.3%
6.50	2.0	38	0.96	31.0%	5620	26.3%
6.53	2.0	38	0.93	31.0%	5870	26.3%
6.46	2.0	38	1.04	30.5%	6100	25.9%
6.41	2.0	38	1.06	30.0%	6350	25.5%
6.41	2.0	38	1.06	30.0%	6850	25.5%
6.38	2.0	38	1.00	29.5%	6970	25.1%
6.39	2.0	38	0.91	29.5%	7110	25.1%
6.39	2.0	38	0.96	29.5%	7250	25.1%
6.30	2.0	38	1.01	29.1%	7300	24.7%
6.31	2.0	38	0.97	29.1%	7450	24.7%
6.31	2.0	38	1.02	29.1%	7550	24.7%
6.33	2.0	38	0.98	29.1%	7800	24.7%
6.29	2.0	38	1.05	28.6%	7880	24.3%
6.23	2.0	38	1.03	28.1%	7990	23.9%
6.25	2.0	38	1.03	28.1%	8150	23.9%
6.15	2.0	38	0.98	27.2%	8270	23.1%
6.08	2.0	38	1.00	26.7%	8345	22.7%
6.03	2.0	38	1.08	26.2%	8595	22.3%
6.02	2.0	38	0.97	26.2%	8995	22.3%

** MW/km refers to ridgelines; 4 x 15 RD is for flat areas*
*** assuming each 0.01 kg/m³ change in air density is 0.8% change in energy production*

Summary of Utah WREZ Prospects
Drainage Canyon Sites

Name	County
Logan	Cache
Hyrum	Cache
Ogden	Weber
South Weber	Weber/Davis
Emigration	Salt Lake
Parleys	Salt Lake
Provo Canyon	Utah
Spanish Fork	Utah
Millsite Reservoir	Emery
Escalante	Garfield
Springdale	Washington