



INTEROFFICE MEMO

EUGENE WATER & ELECTRIC BOARD

POWER RESOURCES DIVISION

Rely on us.

TO: Commissioners Farmer, Brown, Cassidy, Cunningham, and Ernst

FROM: Dick Varner

October 27, 2009

RE: Harvest Wind Project

ISSUE

As Harvest Wind prepares to come on-line, what is the status and what future decisions face the Board?

BACKGROUND

In the fall of 2007, EWEB was approached about its interest in a follow up to the White Creek Wind Project. The Board authorized the staff to move forward in May 2008. In July, the Board approved a resolution authorizing EWEB to enter into a Joint Ownership Agreement with other entities. In the fall, the Board confirmed EWEB participation at the 20 MW level and authorized a project budget of \$32 million on EWEB's part. While the authorized expenditure level on the project is \$32 million, the Board was informed that its share of the project could cost approximately \$50 million if tax equity investors could not be found. (This \$50 million is about equal to the reserves and borrowing authority which has been committed to resource acquisition.) On June 2, 2009, the Board approved a resolution authorizing EWEB to spend up to \$50 million to complete the development of the Harvest Wind Project.

The four joint owners are EWEB, Cowlitz PUD, Lakeview Green Energy (a subsidiary of Lakeview Light and Power), and Peninsula Light (PenLight). The parties intended to follow a similar business model to the White Creek project. In that instance, the utilities sold the project to some investors with an option to purchase the project back in the future. The investors supplied a little less than 50 percent of the capital and some output guarantees in return for the tax benefits. The utilities provided the remainder of the capital through a pre-purchase of power for the project output for 20 years. The cost of project output for the utilities is essentially the debt service on their pre-purchase of power payment plus actual O&M cost.

The team for this project includes many of the same consultants and contractors have been used to take advantage of the White Creek project experience. This includes the project management firm, construction management firm, attorneys, financial advisor, and project engineering firm.

The original project timeline had a goal for commercial operation of December 31, 2009. The project development timeline currently shows commercial operation between December 4 and December 15, 2009.

The utilities selected Siemens 2.3 MW turbines for the project. The total contract price including delivery and set-up is about \$162 million. Siemens and its subcontractors are complete with erection of the 43 wind turbines and are working on commissioning the units.

The contract for the remainder of the construction was competitively bid and RES America was selected as the prime contractor. While the project budget for this work was almost \$32 million, the work is almost complete and the estimated final cost of their part of the project is several million dollars below budget.

The two cooperatives (Lakeview and PenLight) have formed a Limited Liability Company (LLC) and have taken the lead on building the transmission lines between the project and the existing White Creek substation as well as the east side collector substation. They have worked with Klickitat PUD (the local utility) and the owners of a neighboring wind project (enXco) to find the most economical way to connect the project. They have a design/build contract for this work and the work is nearing completion. There is a contract nearly ready for execution that would transfer the substation and transmission line to Klickitat PUD when completed and then contract for use of these facilities.

Interconnection with the Bonneville Power Administration has been contracted and BPA is doing the work necessary at BPA's Rock Creek substation to meet the project completion date.

The Harvest Wind utilities and the owners of the neighboring White Creek project have conceptual agreement about a joint operations and maintenance contract which will save both projects significant O&M and capital costs. The contract is currently being drafted and working toward being final on or about commercial operation.

The latest issue of the project newsletter produced by one of our consultants is attached. It has more information on project status.

There is a provision in Washington's renewable portfolio standards legislation (I-937) that gives a bonus for projects which meet certain prevailing wage and apprenticeship standards. The utilities have included provisions in the construction contracts to be in compliance with this provision. If successful in meeting those standards, then the utilities will get a 20 percent bonus in renewable energy certificates good only for Washington renewable portfolio standard (RPS) compliance purposes. For EWEB, these bonus renewable energy certificates (RECs) probably won't help us with our Oregon RPS compliance but probably will have value for sale in Washington.

DISCUSSION

Project Ownership Structure

The financing plan for the project has changed several times as time has passed and external economic events have occurred. The original tax owner concept eventually was abandoned because potential tax owners wanted significantly greater returns and the tax benefits shifted such that the additional costs and risks associated with this structure didn't justify complications.

The current plan has the owners electing to have the project be a taxable tenancy in common arrangement for federal tax purposes (essentially as Schedule C). The attorneys believe this makes the entity eligible for a federal grant of about \$63 million. The actual grant application will be made at the time of commercial operation and the funds should be forthcoming in about 60 days (February 2010).

The attorneys have advised that we should structure the project so that the tenancy in common entity has business relationships separate from the individual utilities and can show that it operates as an entity unto itself.

One facet is that each utility is expected sign a 20 year energy purchase agreement with the project entity. The ultimate effect will be that each utility will pay its share of direct O&M plus \$37 per MWh. This yields an estimated cost per MWh of about \$60 which qualifies as a market equivalent rate. This is important to show that the energy purchase agreements are the equivalent of an arm's length transaction between the project entity and the utilities. To the extent that surplus funds accumulate in the project entity, the project entity management committee may issue a dividend but if they do so, it needs to go back in proportion to ownership. In the project proforma, excess cash flow from the energy purchase agreements are shown coming back to the utilities to help offset debt service costs.

See **Attachment A** which shows the ownership and flow of funds.

There will be several on-going relationships between parties and Harvest Wind. These include administrative, accounting, auditing, tax returns, consulting engineer, O&M contractor, local transmission provider, wind forecasting, power scheduling, etc. Most of these relationships will be between the Harvest Wind project entity and the various parties. This has some administrative benefits and provides further evidence that the Harvest Wind project entity is in fact separate from the utilities.

This entity will be subject to federal taxation but should not incur any taxes during its operation. The primary reason for this is that only half of the grant needs to be included in income. Thus, the project should have more expenses than income over time.

At some point in the future (after a minimum of 5 years), the utilities may "dissolve" the project entity for federal tax purposes. This would only happen when and if any federal tax liability would be minimal. Federal tax liability is determined by comparing an independent appraisal of project market value with tax basis and accumulated net operating losses.

Project Financing

The total project cost including the transmission facilities is expected to be about \$225 million. EWEB's share of that is \$45.5 million. This should be the extent of EWEB's investment at year-end 2009. Once the grant is received, EWEB's would receive back about \$13 million which would reduce our share to \$32.75 million. After all is said and done, this would be very close to the amount of money EWEB had originally expected to pay as the total of its beginning capital share plus the tax owner buyout amount.

To qualify for the federal grant, each of the utilities needs to provide its share of the capital in the form of taxable borrowing or cash from reserves. In EWEB's case, the current view is that we would use taxable borrowing (in addition to the small increment of reserves already contributed to the project) to fund our share. One spin off benefit of taxable borrowing is that we are able to use the power for our system or to sell to any other party without restriction.

If and when the taxable Harvest Wind entity was "dissolved", EWEB could issue tax-exempt bonds to refinance its share of the project costs. If EWEB uses tax exempt financing, then at least 95 percent of the power must come to EWEB's system to serve EWEB retail customers.

Cost of Project Output

In the original proforma work for the project done in mid-2008, EWEB was expecting it to cost about \$61 per MWh for the power from the project at the project bus bar with an escalation rate less than inflation. After year 10, there was expected to be an increase of about \$6 per MWh when the tax owner was bought out. The expected busbar cost in 2029 was \$78 per MWh. Forecast power prices and market value of RECs appeared to easily cover the cost including adders for transmission across Klickitat PUD and BPA's systems. See Attachment B.

The current expected cost of project output at the project bus bar is expected to be about \$62 per MWh escalating at less than inflation assuming level debt service over 20 years with the cost in 2029 being about \$80 per MWh. However, the cost of Klickitat PUD wheeling and BPA integration are substantially higher than originally forecast. The total of those two items is about \$13 per MWh rather than the \$4 per MWh included in the original analysis. See Attachment C.

Use of Power and RECs from Harvest Wind

There are decisions coming up for the Board on how to dispose of the output and RECs from Harvest Wind.

As you heard earlier this fall, EWEB has more firm power than is forecasted to be needed to serve expected load for the next several years. Likewise, EWEB expects to have substantially more Renewable Energy Certificates (RECs) than are needed for Oregon Renewable Portfolio Standards (RPS).

Operating under our Power Risk Management Policies, staff would be looking to sell power equivalent to the output of Harvest Wind for at least the next two years. At current forward prices and without selling the RECs, this would generate a negative cash flow of about between \$1.5 and \$1.75 million. Sale of the RECs in the NW markets might reduce that by \$400,000 to \$500,000 per year.

An alternative might be to look for a longer term deal in a market where power and RECs together have a higher value. Given the transactions which have been done with some entities, there is the potential to reduce the early year negative cash flow to less than \$500,000 per year or perhaps to have a small surplus.

See Attachment D.

Current staff thinking is that the best economic value for EWEB's customers would be to sell the Harvest Wind power and RECs for the first 5 years and then reassess our position at that point in time. Staff is researching what form that sale might take and will be coming to the Board for approval at some point in the future.

As for the Washington bonus RECs, if the project is successful in getting such recognition in the state of Washington, staff will be looking for a Washington party who would purchase those RECs on a long-term basis from EWEB.

On the subject of RECs, the project has received preliminary certification from California that power from Harvest Wind will qualify under California's RPS. Similar efforts are underway with Oregon and Washington.

RECOMMENDATION/BOARD ACTION

To prepare for project closing, the project attorneys are requesting each utility sign the 20 year energy purchase agreements as soon as practical and hopefully by the November 4th Harvest Wind Management Committee meeting. As such, staff is recommending that the Board approve resolution 09xx authorizing the general manager to enter into a 20 year energy purchase agreement for an approximate 20 MW share of the output of the Harvest Wind project.

There will likely be other Board actions necessary as we go forward. For example, if and when, staff has a potential long-term sale contract for power and/or RECs, this will come back to the Board for action. Also, staff will be coming back probably between now and February to approve the long-term financing for the project.

If you have questions, please contact Dick Varner at dick.varner@eweb.org or 685-7133.

the Wind Farmer



HARVEST WIND
— PROJECT —

Newsletter

October 2009

Nearing Completion



The Harvest Wind 98.9 MW wind project is nearing completion, with commercial operation on schedule for December 15, 2009. All forty-three wind turbines are now erected. Of the forty-three, fifteen of the wind turbines have had the mechanical completion walk downs completed, the punch lists finalized, and mechanical completion certificates issued. By the end of the first week in November, all forty-three mechanical walk-downs will have been completed. Those wind turbines that have been issued the mechanical completion certificate are now being unit commissioned.

ELECTRICAL

The substation for Harvest Wind-East is 100% complete and energized. A 230kV transformer has been added to the Harvest Wind-East substation and is now ready to receive and transmit the power generated from Harvest Wind-East. The five circuits for the Harvest Wind electrical collection system have been energized. As of November 1st, BPA will be able to accept at the Rock Creek Substation up to 25 MWs of power generated from Harvest Wind. By December 15th BPA will have completed the necessary equipment installations to be ready to receive all 98.9 MWs of Harvest Wind power.





RESTORATION

Goodfellow Brothers, Inc. (GBI) has completed the restoration work on the Harvest Wind-West roads. All of the shoulders of the west side roads have been reclaimed and reseeded. New fences and cattle guards have been installed to allow the landowners to continue their livestock pasturing practices. GBI has now moved on to Harvest Wind-East to begin the restoration work. Along with GBI's restoration efforts, Robinson Brothers Construction is restoring the areas impacted by the electrical collection systems. All restoration work is expected to be completed and crews off site by Thanksgiving.



COMMUNICATION

Telephone lines have been installed to allow communication at the Harvest Wind-East substation. BPA is expected to have their communication system equipment installed and functioning by early November. The SCADA system that controls and views the wind turbine activities is now installed in the O&M facility. The Siemens' Grid Monitoring System panels are completed, and the work to integrate the SCADA data in the O&M building servers is underway.

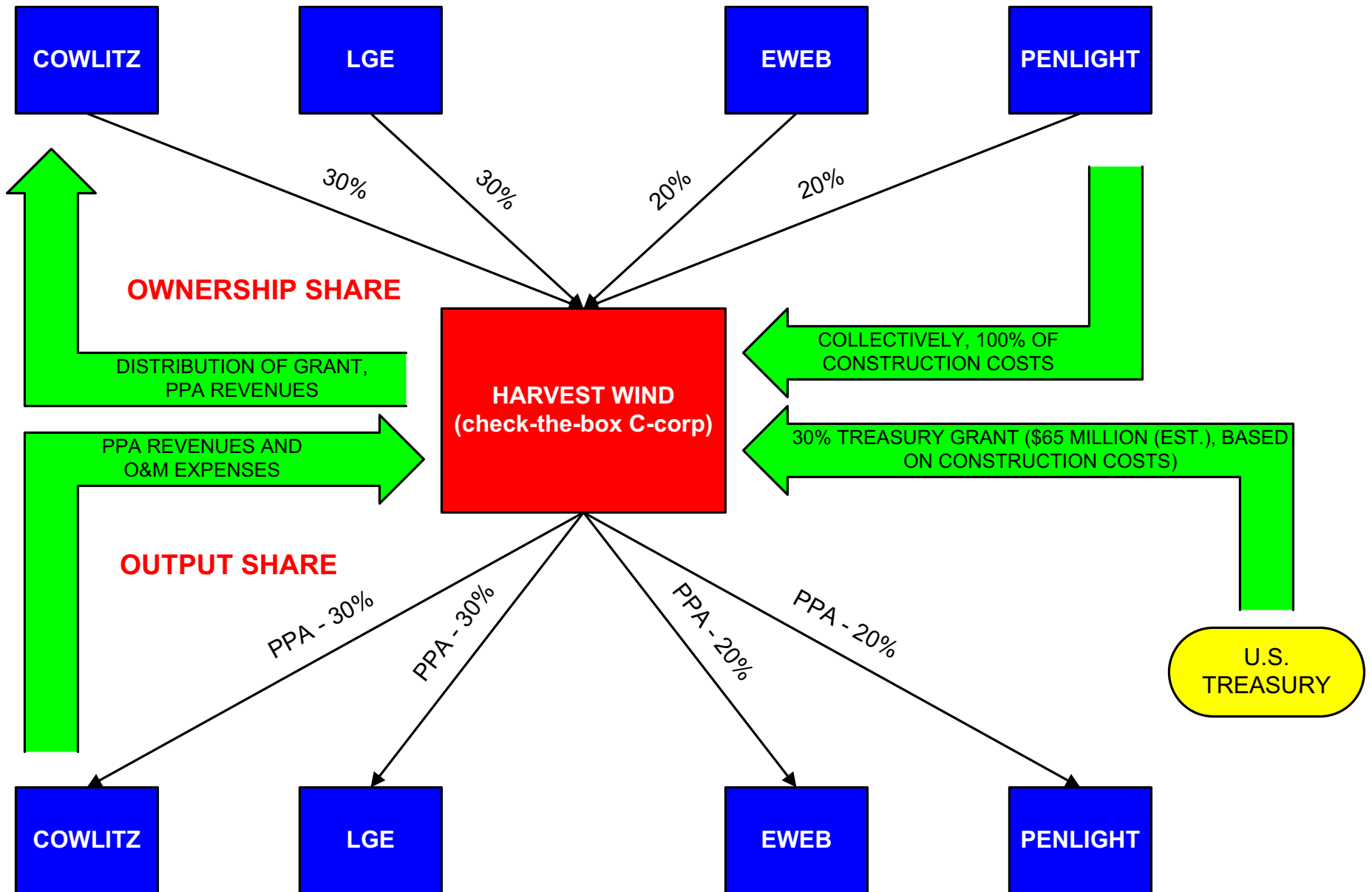


O & M SERVICES

North American Energy Services (NAES) has been awarded the Operations & Maintenance contract for Harvest Wind. NAES, which is already the O & M service provider for White Creek Wind I, will be on site taking over the operation and maintenance of the Harvest Wind turbines as Siemens commissioning crews complete their work. Earlier this year the White Creek Wind I operations and maintenance facility was expanded, a parts and tools warehouse constructed, and modifications made to the offloading and staging areas in order to jointly share the facility with both wind projects, White Creek Wind I and Harvest Wind.

"We believe that 'farming' the wind holds great promise for rural economic development. These environmentally friendly projects are the world's fastest growing form of power generation. There are great benefits for the local tax base, local employment, local subcontracting, local purchasing, and particularly for landowners where the wind turbines will be located. Our neighborhood has the best wind resource in the Northwest, and the timing for developing this clean power source couldn't be more fortuitous."

OPTION 2A PROJECT OWNED/OPERATED BY UTILITIES
(NO PREPAY PPAs)



HARVEST WIND PROJECT - BASIC FINANCING MODEL

Input Data

Project Information

Number of WTGs	35
Capacity per WTG	2.3
Project Capacity (MW)	80.5
Project In Service Date	12/31/2010

Capacity Factor & Output

	Cap Factor	(MWH)
P-50	27.92%	196,886
P-99 (Tier 1)	23.09%	162,826
P-50-P-99 (Tier 2)		34,060

Adjustment of Output for Land Leases

P-50 Output	196,886
Less 4% for land leases	7,875
Net output to participants	189,011

PPA

Tier 2 Initial Power Price (2011)	\$3.00
Opex Inflation Rate	2.50%
Tier 2 Surcharge Yrs 1-10 (\$/MWh)	\$0.00
Tier 2 Surcharge Yrs 11+ (\$/MWh)	\$36.00

Financing Parameters

	Prepay	Buyout
Term	20	10
Amount	\$ 99,179	\$13,000
Interest Rate	6%	6%

The buyout amount of \$13,000,000 is based on the estimated WC1 buyout, and could change significantly.

Sources of Funds \$(000)

PPA Payment Amount	\$	99,179
Equity Investment		91,550
Total	\$	190,729

% funded from Equity Investment 48%

Uses of Funds \$(000)

Turbines	\$134,087	(Based on WC 1 cost per turbine increased by 30%)
Balance of Plant	16,536	(Based on WC 1 cost per turbine increased by 20%)
Common Facilities	1,278	(Based on WC 1 cost per turbine increased by 20%)
Project Management	4,000	(Reduced from \$5,069 for WC1)
Project Advisory	5,000	(Reduced from \$8,811 for WC1)
Debt Financing Costs	3,000	(Reduced from \$4,085)
IDC	10,000	(Reduced from \$17,409)
Equity Placement	2,250	(Approximately 2.5% of equity investment)
Start Up & Commissioning	328	(Based on WC 1 cost per turbine increased by 20%)
Contingency	8,000	(Reduced from 12,000 for WC)
Initial Working Capital	250	(50% of WC 1 working capital)
Rock Creek Latecomers Fee	5,000	
Permitting/Other	1,000	
Total	\$190,729	

NOTE: BLUE NUMBERS ARE VARIABLES ON INPUT SHEET

HARVEST WIND PROJECT - BASIC FINANCING MODEL

Cost of Power with Buyout

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Net Energy Generation	189,011	189,011	189,011	189,011	189,011	189,011	189,011	189,011	189,011	189,011	189,011	189,011	189,011	189,011	189,011	189,011	189,011	189,011	189,011	189,011
Tier 2 Energy Payments	\$102,181	\$104,735	\$107,353	\$110,037	\$112,788	\$115,609	\$118,488	\$121,481	\$124,497	\$127,610										
Tier 2 Surcharge																				
Debt Service - Prepayment	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892	\$8,646,892
Debt Service - Buyout											\$1,766,283	\$1,766,283	\$1,766,283	\$1,766,283	\$1,766,283	\$1,766,283	\$1,766,283	\$1,766,283	\$1,766,283	\$1,766,283
O&M Expenses & Direct Reimbursable Costs																				
Operations & Management (1)	\$469,534	\$481,272	\$493,304	\$505,637	\$518,278	\$531,235	\$544,515	\$558,128	\$572,082	\$586,384	\$601,043	\$616,069	\$631,471	\$647,258	\$663,439	\$680,025	\$697,026	\$714,452	\$732,313	\$750,621
Contractual S&M (1)	1,104,270	1,131,877	1,160,174	1,189,178	1,218,907	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
S&M (1)	-	-	-	-	-	1,249,380	1,280,615	1,312,630	1,345,446	1,379,082	1,413,559	1,448,898	1,485,120	1,522,248	1,560,305	1,599,312	1,639,295	1,680,277	1,722,284	1,765,341
Land Lease Royalty Payment (2)	(Energy production reduced 4% in lieu of direct payment)																			
Fixed Major Repairs Contingency (1)	-	-	-	-	-	377,528	386,966	396,640	406,556	416,720	427,138	437,817	448,762	459,981	471,481	483,268	495,350	507,733	520,427	533,437
Risk Insurance (1)	295,746	303,140	310,718	318,486	326,448	334,609	342,975	351,549	360,338	369,346	378,580	388,044	397,745	407,689	417,881	428,328	439,037	450,013	461,263	472,794
Liability/Other Insurance (1)	48,649	49,865	51,112	52,390	53,699	55,042	56,418	57,828	59,274	60,756	62,275	63,832	65,427	67,063	68,740	70,458	72,220	74,025	75,876	77,773
Property Tax (3)	355,000	355,000	355,000	355,000	355,000	355,000	355,000	355,000	355,000	355,000	355,000	355,000	355,000	355,000	355,000	355,000	355,000	355,000	355,000	355,000
Privilege Tax (1)	59,845	59,845	59,845	59,845	59,845	59,845	59,845	59,845	59,845	59,845	59,845	59,845	59,845	59,845	59,845	59,845	59,845	59,845	59,845	59,845
Annual kWh of Electric Usage (1)	5,443	5,579	5,719	5,862	6,008	6,158	6,312	6,470	6,632	6,798	6,968	7,142	7,320	7,503	7,691	7,883	8,080	8,282	8,489	8,701
Site Restoration Fund (1)	-	-	-	-	-	185,000	185,000	185,000	185,000	185,000	185,000	185,000	185,000	185,000	185,000	185,000	185,000	185,000	185,000	185,000
Audit/Accounting/Legal Cost Pass Through (4)	85,000	87,125	89,303	91,536	93,824	96,170	98,574	101,038	103,564	106,153	108,807	111,527	114,316	117,173	120,103	123,105	126,183	129,338	132,571	135,885
Independent Engineer (4)	85,000	87,125	89,303	91,536	93,824	96,170	98,574	101,038	103,564	106,153	108,807	111,527	114,316	117,173	120,103	123,105	126,183	129,338	132,571	135,885
Fish & Wildlife Mitigation (1)	26,993	27,668	28,360	29,069	29,795	30,540	31,304	32,086	32,888	33,711	34,553	35,417	36,303	37,210	38,140	39,094	40,071	41,073	42,100	43,152
LLC Management Fee (4) (5)	250,000	256,250	262,656	269,223	275,953	282,852	289,923	297,171	304,601	312,216	320,017	328,017	336,220	344,631	353,254	362,094	371,155	380,442	390,000	399,800
LLC Management Opex (4) (5)	40,000	41,000	42,025	43,076	44,153	45,256	46,388	47,547	48,736	49,955	-	-	-	-	-	-	-	-	-	-
Total Operating Costs	\$2,825,480	\$2,885,746	\$2,947,518	\$3,010,835	\$3,075,735	\$3,140,785	\$3,208,209	\$3,278,249	\$3,350,826	\$3,425,026	\$3,501,875	\$3,580,419	\$3,661,719	\$3,744,826	\$3,830,712	\$3,919,445	\$4,011,095	\$4,105,735	\$4,203,445	\$4,304,305
Total Annual Cost	\$11,574,553	\$11,637,373	\$11,701,764	\$11,767,765	\$11,835,416	\$12,487,286	\$12,547,799	\$12,630,326	\$12,714,916	\$12,801,620	\$13,799,751	\$13,878,295	\$13,958,801	\$14,041,321	\$14,125,903	\$14,212,600	\$14,301,465	\$14,392,551	\$14,485,914	\$14,581,612
Cost/MWH	0.54	0.55	0.57	0.58	0.60	0.61	0.63	0.64	0.66	0.68	-	-	-	-	-	-	-	-	-	-
Tier 2 Energy Payment	45.75	46.75	47.75	48.75	49.75	50.75	51.75	52.75	53.75	54.75	55.75	56.75	57.75	58.75	59.75	60.75	61.75	62.75	63.75	64.75
Debt Service Prepayment	-	-	-	-	-	-	-	-	-	-	9.34	9.34	9.34	9.34	9.34	9.34	9.34	9.34	9.34	9.34
Buyout Prepayment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
O&M	14.95	15.27	15.59	15.93	16.27	16.60	20.01	20.43	20.86	21.31	17.92	18.33	18.76	19.20	19.64	20.10	20.57	21.05	21.55	22.05
Total Cost/MWH	\$61.24	\$61.57	\$61.91	\$62.28	\$62.62	\$65.96	\$66.39	\$66.82	\$67.27	\$67.73	\$73.01	\$73.43	\$73.85	\$74.29	\$74.74	\$75.19	\$75.66	\$76.15	\$76.64	\$77.15

- (1) Based on WC1, adjusted for capacity and increased 20%.
- (2) Land Lease Royalty Payments assumed to be 4% of energy output, which is adjusted accordingly.
- (3) Fixed per MWh. Not paid if project is publicly owned.
- (4) Estimated, assuming costs would not be significantly reduced from WC1.
- (5) Not paid if project is publicly owned.

**HW OPTION 2A
COST OF POWER**

Operation Year Fiscal Year	1 2010	2 2011	3 2012	4 2013	5 2014	6 2015	7 2016	8 2017	9 2018	10 2019	11 2020	12 2021	13 2022	14 2023	15 2024	16 2025	17 2026	18 2027	19 2028	20 2029
GENERATION (MWh)																				
Total Energy Generation	10,988	263,721	263,721	263,721	263,721	263,721	263,721	263,721	263,721	263,721	263,721	263,721	263,721	263,721	263,721	263,721	263,721	263,721	263,721	263,721
Net Energy (after leases)	10,549	253,172	253,172	253,172	253,172	253,172	253,172	253,172	253,172	253,172	250,535	250,535	250,535	250,535	250,535	250,535	250,535	250,535	250,535	250,535
DEBT SERVICE																				
Taxable	\$ 1,015	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182
Tax-Exempt	\$ 1,015	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182	\$ 12,182
OPERATING COSTS & DISTRIBUTIONS																				
O&M Expense	\$ 202	\$ 2,426	\$ 2,486	\$ 2,548	\$ 2,612	\$ 2,677	\$ 2,744	\$ 2,813	\$ 2,883	\$ 2,955	\$ 3,029	\$ 3,105	\$ 3,182	\$ 3,262	\$ 3,344	\$ 3,427	\$ 3,513	\$ 3,601	\$ 3,691	\$ 3,783
Direct Reimbursable Costs	216	2,588	2,864	2,930	2,998	3,068	3,639	3,721	3,806	3,893	3,983	4,074	4,143	4,215	4,289	4,365	4,444	4,526	4,609	4,696
Total Operating Costs	418	5,013	5,350	5,479	5,610	5,745	6,383	6,534	6,690	6,849	7,012	7,179	7,326	7,477	7,633	7,793	7,957	8,126	8,300	8,479
Energy Costs	781	9,367	9,367	9,367	9,367	9,367	9,367	9,367	9,367	9,367	9,367	9,367	9,270	9,367	9,367	9,367	9,367	9,367	9,367	9,367
NewCo Distributions	64,706	9,382	9,382	9,382	9,382	9,382	9,382	9,382	9,382	9,382	9,382	9,382	9,285	9,382	9,382	9,382	9,382	9,382	9,382	9,382
Total Annual Cost Taxable	17,180	17,517	17,645	17,777	17,911	18,549	18,701	18,856	19,015	19,178	19,345	19,492	19,644	19,799	19,959	20,124	20,293	20,467	20,645	22,600
Total Annual Cost Tax Exempt	17,180	17,517	17,645	17,777	17,911	18,549	18,701	18,856	19,015	19,178	19,345	19,492	19,644	19,799	19,959	20,124	20,293	20,467	20,645	22,600
TRANSMISSION TO BPA SUB	155	1,857	1,884	1,911	1,938	1,967	1,996	2,026	2,056	2,088	2,120	2,153	2,187	2,221	2,257	2,293	2,330	2,368	2,408	2,448
TAXABLE COST OF POWER (\$/MWh)																				
Total without BPA Integration	\$ 61.81	\$ 62.99	\$ 63.34	\$ 63.70	\$ 64.07	\$ 66.43	\$ 66.85	\$ 67.29	\$ 67.74	\$ 68.20	\$ 69.39	\$ 69.78	\$ 70.19	\$ 70.60	\$ 71.03	\$ 71.47	\$ 71.93	\$ 72.39	\$ 72.87	\$ 80.44
Total at Project Substation	\$ 67.86	\$ 69.19	\$ 69.70	\$ 70.22	\$ 70.75	\$ 73.27	\$ 73.87	\$ 74.48	\$ 75.11	\$ 75.75	\$ 77.22	\$ 77.80	\$ 78.41	\$ 79.03	\$ 79.67	\$ 80.32	\$ 81.00	\$ 81.69	\$ 82.40	\$ 90.21
Total at Rock Creek Substation	75.20	76.63	77.24	77.87	78.52	81.15	81.87	82.60	83.35	84.12	85.81	86.53	87.27	88.03	88.82	89.62	90.45	91.30	92.17	100.14
TAX EXEMPT COST OF POWER (\$/MWh)																				
Total at Project Substation	\$ 67.86	\$ 69.19	\$ 69.70	\$ 70.22	\$ 70.75	\$ 73.27	\$ 73.87	\$ 74.48	\$ 75.11	\$ 75.75	\$ 77.22	\$ 77.80	\$ 78.41	\$ 79.03	\$ 79.67	\$ 80.32	\$ 81.00	\$ 81.69	\$ 82.40	\$ 90.21
Total at Rock Creek Substation	75.20	76.63	77.24	77.87	78.52	81.15	81.87	82.60	83.35	84.12	85.81	86.53	87.27	88.03	88.82	89.62	90.45	91.30	92.17	100.14
AVERAGE COST OF POWER CALCULATIONS																				
Average Cost of Power (RC)	Yrs 1-5	Yrs 5-10	Yrs 1-10	Yrs 11-20	Yrs 1-20															
Tax-Exempt	\$ 77.09	\$ 82.62	\$ 79.86	\$ 90.02	\$ 84.94															
Taxable	\$ 77.09	\$ 82.62	\$ 79.86	\$ 90.02	\$ 84.94															

HW OPTION 2A INPUT DATA

Note: Blue Numbers are variables

PROJECT INFORMATION

Generation		
Number of WTGs		43
Capacity per WTG (MW)		2.3
Project Capacity (MW)		98.9
Capacity Factor & Output	Cap Factor	(MWh)
P-50	30.44%	263,721
Estimated Costs \$(000)		
Turbines		\$ 164,892
Balance of Plant		25,409
Other		17,933
Contingency		7,000
Working Capital Res		-
Unrecovered Loss Res		-
Interest During Const		-
Total Cost (before syndication fee)		\$ 215,234
Syndication fee		-
Total Costs (less reserves)		\$ 215,234
NewCo (TIC) Reserve Account		500
Total Cost with Reserves		\$ 215,734

FINANCIAL INFORMATION

Interest on Reserves		3.00%
Federal Tax Rate		35%
Grant Calculation		
Cosntruction Costs (Tax Basis)	\$	215,234
% Qualifying for Grant		99.00%
Cost Available for Grant	\$	213,082
Estimated Grant	\$	63,925

Total Cost	\$	215,734
Grant		(63,925)
Utility Long-Term Financed Debt	\$	151,810

Average Cost of Power (\$/MWh)	Taxable	Tax-Exempt
yrs 1-5	\$ 77.09	\$ 77.09
yrs 5-10	82.62	82.62
yrs 1-10	79.86	79.86
yrs 11-20	90.02	90.02
yrs 1-20	84.94	84.94

UTILITY INFORMATION

Borrowing Terms		Taxable	Tax-Exempt
Amortization schedule		20	20
Interest Rate		5.00%	5.00%
Amount	\$	151,810	\$ 151,810
Power Sales Agreement			
ENERGY PRICE	\$	37.00	
Energy Sale Inflation Rate		0.00%	
Operating Exp Inflation Rate		2.50%	
Transmission			
Interest Rate		5.00%	
Term		20	
Amount \$(000)	\$	10,000	
O&M Initial Amt (\$/MWh)	\$	2.00	
Annual Administrative Fee	\$	225	
Initial Fee		50	

D

Harvest Wind 5 Year Cash Flow Estimate

	2010	2011	2011	2011	2011	Total
Harvest Wind Cost (EWEB Share)	3,850,000	3,930,000	3,955,000	3,990,000	4,020,000	
Forecast Harvest Wind Output (EWEB Share)	51,202	51,202	51,202	51,202	51,202	
Forecast Market Price	44.50	51.75	54.00	56.00	58.00	
Sale of Power Only	2,278,467	2,649,678	2,764,881	2,867,284	2,969,687	
Negative Cash Flow Power Sale Only	(1,571,533)	(1,280,322)	(1,190,119)	(1,122,716)	(1,050,313)	(6,215,002)
WECC Wind REC Est Value	8.00	9.25	12.50	13.50	14.50	
Sale of RECs Only	409,612	473,614	640,019	691,220	742,422	
Estimated Negative Cash Flow After Sale of Power and RECs in NW Markets	(1,161,921)	(806,708)	(550,100)	(431,495)	(307,891)	(3,258,115)
Hypothetical Sale of Power and RECs on 5 Year Basis	70	72	74	76	78	
Revenue from Hypothetical Sale of Power and RECs on 5 Year Basis	3,584,105	3,686,508	3,788,911	3,891,314	3,993,717	
Estimated Negative Cash Flow After Hypothetical Sale of Power and RECs on 5 Year Basis	(265,895)	(243,492)	(166,089)	(98,686)	(26,283)	(800,443)

RESOLUTION NO. 0925
November 2009
AUTHORIZING 20 YEAR ENERGY PURCHASE FROM HARVEST
WIND PROJECT

WHEREAS, the Eugene Water & Electric Board ("EWEB") is a municipal utility formed and operated pursuant to ORS Chapter 225, the Eugene City Charter and Eugene City Code;

WHEREAS, ORS 225.020(1) authorizes EWEB to build, own, operate, and maintain electric light and power plants for benefit of its ratepayers and for profit;

WHEREAS, the Board approved resolutions 0821, 0834 and 0918 authorizing EWEB to execute such agreements, including a Joint Ownership Agreement, as may be necessary to develop the Harvest Wind Project ("Project") and to expend up to \$50 million on development of the Project;

WHEREAS, the Joint Ownership Agreement has been executed between EWEB, Cowlitz PUD, Lakeview Green Energy, and Peninsula Light;

WHEREAS, the utility participants own the Project as tenants-in-common under the Joint Ownership Agreement and EWEB's undivided ownership share of the Project is approximately 20 percent;

WHEREAS, in order to become eligible for a federal grant, the tenants-in-common have elected to be treated as a separate taxable entity for federal tax purposes;

WHEREAS, the utility participants must purchase their ownership share of Project energy from the separate tenancy-in-common entity pursuant to an Energy Purchase Agreement in order to obtain favorable federal tax treatment; and

WHEREAS, the tenancy-in-common desires to sell and EWEB desires to purchase an approximate 20 MW share of Project energy and associated environmental attributes pursuant to a 20 year Energy Purchase Agreement;

NOW THEREFORE BE IT RESOLVED, that the General Manager is authorized to sign a 20 year Energy Purchase Agreement for an approximate 20 MW share of Harvest Wind Project energy and associated environmental attributes.

Dated this 3rd day of November 2009

THE CITY OF EUGENE, OREGON
Acting by and through the
Eugene Water & Electric Board

President

I, DEBRA J. SMITH, the duly appointed, qualified, and acting Assistant Secretary of the Eugene Water & Electric Board, do hereby certify that the above is a true and exact copy of the Resolution adopted by the Board at its November 3, 2009 Regular Board Meeting.

Assistant Secretary