Oregon Wave Energy Trust
Utility Market Initiative

Task 3.3.2: Value of Wave Power – Model Documentation

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The Utility Market Initiative was prepared by *Pacific Energy Ventures* on behalf of the Oregon Wave Energy Trust.

Task 3.3.2 was completed by Energy Focused Resources.

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About Oregon Wave Energy Trust

The Oregon Wave Energy Trust – (OWET) - with members from fishing and environmental groups, industry and government - is a nonprofit public-private partnership funded by the Oregon Innovation Council in 2007. Its mission is to serve as a connector for all stakeholders involved in wave energy project development - from research and development to early stage community engagement and final deployment and energy generation - positioning Oregon as the North America leader in this nascent industry and delivering its full economic and environmental potential for the state. OWET's goal is to have ocean wave energy producing 2 megawatts of power - enough to power about 800 homes - by 2010 and 500 megawatts of power by 2025.

Value of Wave Energy - Model Documentation

1. Model Documentation

1.1. Introduction

The centerpiece of the value and cost calculation is an Excel 2003-compatible financial model that uses multiple sheets. References are cited for information provided by third parties that was sufficiently generic for use in the model. In many cases information is simply not available publically. In other cases, particular assumptions would be clearly representative of a particular technology which would violate a technology-neutral look at wave power. Therefore, in most cases assumptions are based on experience, rules of thumb, and/or forecasted market values. The intent is to arrive at a reasonable starting point for discussing value and costs so that policies can be explored and an eventual contractual middle-ground can be reached.

There are two versions of the model: one for valuation that assumes recent forecasted market prices and a second version that changes the market price to a breakeven point in order to determine the cost of the project. The two methodologies are best accommodated by using different versions of the same basic model. Differing assumptions between the models are identified and explained where appropriate in the documentation.

1.1.1. Using the Model

The model is a typical excel workbook and does not employ any macros. Each sheet in the workbook represents a set of factors that feed into the valuation model. There are four colors that are explained on the KEY sheet: input cells (green), calculated cells (blue), exported cells (yellow) and imported cells (red). Of most importance are the user-defined green fields which are the user-defined assumptions. Some cells have two colors which indicate that multiple operations are affecting a cell. For instance, a blue-yellow cell signifies a calculation is taking place in the cell, the value of which is referenced in (or exported to) another sheet.

The documentation assumes that users have a working knowledge of excel functions. For those users interested in probabilistic outcomes, the model can be easily adapted to Excel simulation add-ons such as @RISK.

1.2. Assumptions

There are several overarching assumptions that are relevant across the entire workbook. These assumptions drive many of the more detailed assumptions in the spreadsheet. Detailed assumptions are made and described in the model documentation section.

Changes to any of the core assumptions require a systematic and holistic inspection of the model by the user and careful audit of all inputs. This should be possible by one with modest skills in Excel

1.2.1. Project Assumptions

The model assumes a 100MW wave farm with two hundred 500kw units deployed over two consecutive summers. Changing the scope of the project will have far-reaching repercussions to other portions of the model, for example how many employees are needed to service equipment and how many boat-days are necessary each month.

The project assumes a stand-alone company life of 20 years and an asset life of 15 years. Construction and installation occurs in the middle of years three and four and the assets are removed in year 19. When assets are deployed or removed changes when certain expenses will be experienced.

1.2.2. Return on Equity

A major assumption in determining the cost of wave power is that Return on Equity is paid as a dividend and that the company returns capital to investors (shareholders and bondholders alike) at the termination of the project. In reality this is highly unlikely to happen (especially in the short-term with debt covenants), but this form of modeling assures that there is not a massive amount of retained earnings accumulating in the company that will cause incentive-providers to balk and simultaneously protects the expected return for investors who are absorbing the uncertainty in the project. There is more on this assumption and related assumptions in the FUNDING and COST CAP sheets.

1.2.3. Rates

Integration and Transmission rates and costs are all based on Bonneville Power Administration practices and Schedules.

1.3. Value Inputs and Calculations

Value is the first focus of the model because Value is a subset of information that also affects cost of the project. The ten sheets that substantially contribute to the value calculation are:

- COST CAP,
- RESOURCE&ABSORBER,
- PRICES,
- CONNECT,
- GEN IMB,
- ANCILLARY,
- TRANSMISSION,
- OPEX&COR,
- REVENUE, and
- VALUE,

1.3.1. COST CAP sheet

The Cost of Capital sheet contains assumptions about the cost of capital, discount rates and capital structure of the wave project. These assumptions permeate almost all portions of the workbook and substantially influence the economics of the project.

1.3.1.1. Weighted Average Cost of Capital

A weighted average cost of capital (WACC) calculation is often performed in order to value a firm. In this case, the calculation is suggesting a WACC for those parties interested, but more importantly to supply WACC-based inputs for use elsewhere in the spreadsheet. WACC is typical defined as:

WACC=y*c+x*i*(1-t), where

y = portion of equity in the capital structure,
c = cost of equity (after tax),
x = portion of debt in the capital structure,
i = cost of debt,
t = tax rate.

The portion of debt in the capital structure is an input field (cell E29); the equity percentage (cell E30) is calculated as the remainder. The model assumes a 60% equity, 40% debt project based on capital market conditions in mid-2009. As these are atypical market conditions, this figure may fluctuate widely between now and the time that an actual project is launched. Historically, leverage could be as high as 70-80% particularly with proven technologies and long term purchase agreements with high-quality credit regulated utilities, but even proven wind technologies faced Debt to Equity ratios of near one[i] before the Financial Crisis of 2008.

The cost of equity is described two section below, and the tax rate was imported from the TAXES worksheet.

The cost of debt was assumed to be the corporate 20-year A-rated composite bond index.[ii]

Assuming the above factors, the WACC for the project is 13.3%

1.3.1.2. Risk Free Rate

The risk free rate is defined as the 10-Year Treasury yield which at the time of the initial worksheet design was 3.50%. This figure is instrumental in determining the Cost of Equity and is also used elsewhere in the workbook to discount cash flows as an appropriate opportunity cost.

1.3.1.3. Cost of Equity

The cost of Equity is the market risk premium times the equity's Beta plus the risk free rate. The Beta was determined by using two the closest comparables for which data could be found: wind manufacturers Vesta Wind Systems and Nordex AG. Their average Beta is 1.91.[iii]

The cost of equity in this project could vary widely depending on the contract price, the maturity of the technology, the amount of financial leverage desired, and project risk sharing arrangements with other parties.

The market risk premium is the 1926-2002 average risk premium of 8.4%.[iv] This is a relatively high figure versus other periods that have been calculated.[v]

Based on these assumptions, the cost of equity is 19.5%.

1.3.1.4. Transmission Builder's Cost of Capital

The Transmission Builder's Cost of Capital is used to determine the total capitalized cost of investments made by the transmission provider, in particular the interest incurred, on behalf of the developer. Keeping in mind that BPA is a Federal Agency with special accounting rules, BPA's cost of capital of 3.94% was determined by adjusting debt figures from the annual report and then dividing the interest expense by the adjusted total debt figure.[vi] Note that this is an average cost of capital and not a project- or asset-specific cost of capital.

1.3.1.5. Inflation Rate

The inflation rate is used throughout the workbook to forecast increases in costs. This means that the pro forma financials are in nominal and not real dollars. An average inflation rate of 2.82% from the 1999-2008 Consumer Price Index (CPI) was used.[vii]

1.3.2. RESOURCE&ABSORBER sheet

The Resource and Absorber sheet contains information about the resource, the generating characteristics of the machine exploiting the resource, and resulting calculations of energy (and REC) production by month by Heavy-Load Hours (HLH or on-peak) and Light-Load Hours (LLH or off-peak).

The following subsections are in order of what can be seen in the sheet from top to bottom.

1.3.2.1. Nameplate Capacity per Unit

This is an input field that captures the nameplate capacity of the units in the project. The number is expressed in kilowatts (kW). 500 kW was assumed based on the size of units currently being contemplated in the marketplace by manufacturers, though there is a wide range above and below this figure. The model does not accommodate multiple technologies or capacities without alteration.

1.3.2.2. Number of Units Operational

This input field shows the number of units assumed to be deployed and generating on a month by month basis. The analysis assumes crews (and two workboats later on in the model) working in May and June of Year 3 but actual connection of the first 20 units occurring on July 1. The build-out is also not as aggressive in Year 3 as in Year 4 as a learning curve is expected, and there are no deployments in the winter as it is assumed that the weather is too rough for plant build-out during the resource-peak season. Maintenance and Repair work does take place in the winter at a more intensive pace.

1.3.2.3. Unit Deployments; calculated field

Unit deployments is a calculated field that makes it easier to see the incremental additions of units from month to month.

1.3.2.4. Plant Nameplate Capacity

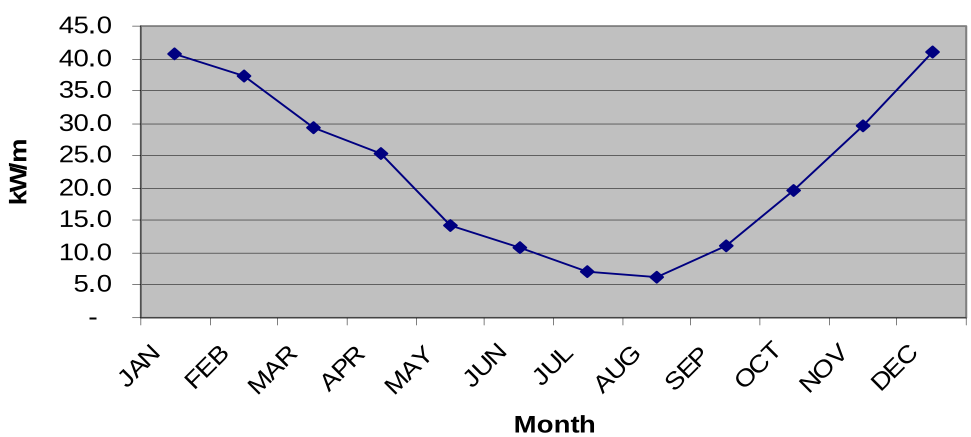
This calculated field multiplies the number of operational units times the capacity per unit to give a plant total nameplate capacity in megawatts (MW).

1.3.2.5. Maintenance Schedule

The maintenance schedule is the average number of units offline each month. This affects plant generation and other overhead costs, so it is an important factor to determine. It is assumed that all units need a 10-day maintenance each summer and all units cycle through maintenance once per year. A figure of 17 units off-line for a month actually means that roughly 17 (units on average) * 3 (30 days per month/10 days per unit turnaround) =51 units are actually serviced in the time period referenced.

1.3.2.6. Mean Resource

The mean resource is an input field assumed to be the average kW/m readings from the Coquille buoy that was in 64 meters of water off the coast of Oregon. This site was selected for its representative depth and the time in service.[viii]



1.3.2.7. Resource Percent of Mean Resource

This is a calculated field that normalizes the resource for further calculations; an average monthly resource is established herein as 100% or 1.

1.3.2.8. Annual Expected Capacity Factor

This is an input field that captures the monthly average capacity factor of the unit over the period of a year. This is defined as the average hourly amount of energy generated for the year divided by the nameplate capacity of the project. For example, if 28 MW per hour on average are produced by the project and the nameplate capacity of the project is 100 MW, then it would be described as 28/100 = .28 or 28%. The base case assumes a 35% capture of the resource for all years and account for deviations from this figure through scheduled and forced outages and monthly resource capture rates.

1.3.2.9. Monthly Capacity Factor

The monthly capacity factor is a calculated field that multiplies the percent of mean resource times the annual expected capacity factor to arrive at a monthly capacity factor for the project. In essence, this is backing into an energy production schedule by doing these calculations in this manner. There is room for improvement for this methodology by incorporating more granularity with specific unit knowledge and how the technology interacts with various sea states.

1.3.2.10. Forced Outage Rate

The forced outage rate is the percent of time that the project is out of service after accounting for scheduled maintenance. This is an aggregate project number and includes both partial and full outages. This figure also accounts for outages due to very high-energy sea states when units de-rate themselves or go into a survival mode, explaining the high variability of this figure from winter (7%) to summer months (1%).

1.3.2.11. Monthly Peak Generation

To the right of the large, calculated field is a small input field. The input field is the maximum generation one can expect from the resource for a single hour on a monthly basis. Although these monthly calculated fields are not currently used elsewhere in the workbook for determining cost or revenue, they could be under some scenarios, especially if rate structures change. The annual figure is used for determining the amount of firm annual transmission purchased and is exported to the TRANSMISSION sheet.

1.3.2.12. Hours per Month

To the right of the large, calculated field is a small input field for entering the numbers of days per month. These figures are multiplied by 24 to arrive at the number of hours per month. Note that leap years are not included.

1.3.2.13. HLH per Month

Every hour of the year is defined as a Heavy-Load or Light Load Hour (HLH and LLH). The calculated small field to the right of the larger calculated field determines the HLH to Total Hours ratio. Heavy Load Hours are Monday through Saturday from 6 a.m. to 10 p.m. except NERC holidays.[ix] For those months with NERC holidays, the average occurrence of the holiday coinciding with a weekday is assumed if the holiday can fall on any day of the week. In the cases of Labor Day, Memorial Day and Thanksgiving, the full 16 hours are deducted from HLH hours. When actual years are used these figures can be updated with the actual NERC schedule (an leap year) information. The larger field is calculated by multiplying the ratios established to the right and multiplying by the total hours.

Though it is assumed that there is no diurnal shape to wave power in the analysis, the model is able to handle simple (HLH and LLH) diurnal pricing if a user so desires.

1.3.2.14. LLH per Month

Light-Load Hours (LLH) are determined as Hours per Month less HLH per Month.

1.3.2.15. Total MWh Production

This calculated field determines the total plant production per month in MWh. Total MWh production is defined as the nameplate capacity of the plant less the planned outage capacity times one minus the forced outage rate times the number of hours in the month. In the actual workbook calculation there is a capacity translation into kW which is converted back to MW by dividing by 1000.

1.3.2.16. HLH MWh Production

This calculated field multiplies the total MWh per month figure times the HLH to Total Hours ratio.

1.3.2.17. LLH MWh Production

This field calculates the LLH to Total Hour ratio and then multiplies by the Total MWh in the period to arrive at a monthly LLH MWh production figure.

1.3.2.18. No Station Service

The model assumes there is no station service.

1.3.3. PRICES Sheet

The prices sheet captures information about market prices or market forecasts for energy and RECs. This price forecast is from a combination of third party sources. The power market is among the most volatile market in the world and users should expect to update and negotiate with counterparties regarding valuations including the relationships of pricing between months within a year and between LLH and HLH hours. Forward prices in lieu of forecasted prices should be used when available. Carbon Dioxide (CO2) prices are not explicitly modeled and are assumed to be reflected in the price of energy as parties who offer carbon-based energy into the market will figure CO2 costs into their price bids and offers in the future.

1.3.3.1. Forecasted Annual RTC PNW Westside Prices

Forward Annual Round-the-Clock (RTC) Pacific Northwest (PNW) Westside Prices are expected prices for delivery to points on the western side of the cascades. This power typically trades at a premium to the eastern side where the bulk of regional generation resides.

These prices are those *annual* figures used in the Draft Northwest Sixth Power Plan.[x]

1.3.3.2. Monthly Price Factors

The input field Monthly Price factors are the percentage of the annual price that each month exhibits and is representative of the year 2011. Changes in later-year figures are not significant. These figures were supplied by a regional commercial interest that wishes to remain anonymous.

1.3.3.3. Forecasted Monthly RTC PNW Westside Prices

This calculated field is the result of combining the Monthly Price factors with the Forward Annual RTC prices

1.3.3.4. HLH Price Factors

HLH Price Factors are an input field is defined as the HLH price divided by the corresponding total price. These figures were provided by the same source that prefers to remain anonymous. In this case the figures for Year 1 correspond to the year 2011; the curve provided only ran out to the year 2015 (Year 5 in the model) therefore all subsequent years (post-year 5) are assumed to have the same ratio relationships as the last forecasted value.

1.3.3.5. LLH Price Factors

These figures for LLH hours were derived in the same way as the HLH Price Factors.

1.3.3.6. Forecasted Monthly HLH Mid-C Power Prices

This field is calculated by multiplying the Forecasted Monthly RTC PNW Westside Energy Prices by the HLH Price Factors for each month.

1.3.3.7. Forecasted Monthly LLH Mid-C Power Price

This field is calculated by multiplying the Forecasted Monthly RTC PNW Westside Energy Prices by the LLH Price Factors for each month.

1.3.3.8. RECs / Green Tag Forecasted Prices

The forecasted REC curve was derived from a verbal polling of market participants. The market is illiquid and opaque. Consensus is that prices in 2009 to 2010 are in the $6-$8 dollar range and some participants have modeled prices toward $20 per REC in 2020. The model increases prices for RECs from $7.50 in years 1-4 (corresponding to the Oregon RPS[1] of 5% from 2011 to 2014) to $15 in years 5-9 (corresponding to the Oregon RPS of 15% from 2015-2019) to $20 in years 10-14 (corresponding to the Oregon RPS of 20% from 2020-2024) to $25 for all years beyond to the Oregon RPS of 25% from 2025 onwards).

This is all highly speculative because the only way to secure long-dated RECs is to transact with a long-term generating facility. The issue there is that the number of RECs the utility can expect to get from the projects is variable, which increases utilities' price and rate risk greatly. RECs are volatile and opaque with considerable potential value and uncertainty.

1.3.4. CONNECT sheet

The Connect sheet accounts for substation capital costs incurred by third parties to connect the project to the transmission grid. It also separately allows for connection to a distribution system at the bottom of the sheet (not modeled in the base case). The current model assumes $5 million for the connection of a 100MW project directly to the BPA Transmission system, but the actual costs and lead-times will vary widely from site to site depending on existing infrastructure, right-of-ways, and hardware needs. The Transmission connection costs can be calculated in two ways for the project: either the entire costs must be funded by the Project Owner up front (Advance Funding Rate) or if all or a portion of the upgrades are for benefits of other parties then the Use-of-Facilities Rate can be applied which allows for investment by BPA and payments by the developer to the utility to recoup costs over a longer period of time.

The selection for which of the Transmission rates is used is in sheet OPEX&COR cell B19 by selecting "Y" or "N" in the cell in response to Use-of-Facilities charge. If the connection is assumed to be advance funded ("N" in cell B19) this is considered a capital cost of the plant and is captured in row 13 of sheet PLANT CAP. If the connection will be paid back over time, the information is shown on sheet OPEX&COR cells C20:V20. The Advance Funding Rate is assumed in the base case.

1.3.4.1. Transmission Interconnection

The capital expenditures worksheet is mostly input fields of when capital expenditures will happen. The size of the facility cell (D8) is not linked to any other factors. The "Year of Funding for Advance Funding Rate" cell D27 is important if a lump sum is to be paid to the transmission provider (affects PLANT CAP sheet). For the Use-of-Facilities calculations, the model assumes that interest is accrued for these expenditures which becomes part of the rate. The rate of interest is the cost of capital to BPA, currently calculated to be around 3.94% and is imported from sheet COST CAP. The facility life input in needed for further calculations down the page.

[1] For Large Electric Utilities as defined in the legislation

1.3.4.2. Use-of-Facilities Rate Schedule

The Use-of Facilities Rate Schedule calculates the annual and monthly costs for the Use of Facilities rate. Note that it provides a value for all 20 years even though in this instance it is assumed that the rate only has a life of 15 years. There is a filter in the TRANSMISSION sheet that performs the final calculations for the Use-of-Facilities charges so that only 15 years of payments are made. The rate calculation the payments for and annuity plus assumed maintenance and G&A, adjusted for inflation (imported from sheet COST CAP cell E60). Percent subscribed is the portion of the facility or the project deemed to be for benefit of the developer as opposed to general grid or other party use. The base case assumes 100% for use by the project.

1.3.4.3. Distribution Interconnection

Costs to interconnect directly to a distribution system are captured in cell C73; all funds are expected to be provided prior to construction, the year of payment indicated in cell C72.

1.3.5. GEN IMB Sheet

The Generation Imbalance (GEN IMB) Sheet calculates the cost of forecasting error based on the forecast error of the project and the applicable BPA rate. The bands are the deviation between the scheduled amount of energy and an the actual amount delivered. In general, the larger the forecast error, the higher the cost per unit error. These differences and calculations are accounted for in different size bands. The bands are defined in the BPA Generation Imbalance Rate[xi] which in part states:

> "Deviation Band 1 applies to deviations that are less than or equal to: i) ± 1.5% of the scheduled amount of energy, or ii) ± 2 MW, whichever is larger in absolute value... Deviation Band 2 applies to the portion of the deviation i) greater than ± 1.5% of the scheduled amount of energy or ± 2 MW, whichever is larger in absolute value, ii) up to and including ± 7.5% of the scheduled amount of energy or ± 10 MW, whichever is larger in absolute value... Deviation Band 3 applies to the portion of the deviation i) greater than ± 7.5% of the scheduled amount of energy, or ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value."

Although there are potential risks and opportunities associated with forecast error, the base case assumes non-gaming behavior and assumes that forecasted prices are unbiased estimators of future prices.

Intra-day price fluctuations (which are accounted for as part the BPA rate) are not accounted for in this model but could be substantial, as could a material difference between forecasted prices and actual prices.

1.3.5.1. Energy Imbalance Price Premiums

The energy imbalance price premiums depend on the size of the deviations and are published in the rate. These figures are used in determining the cost of the deviations.

1.3.5.2. Forecast Error Deviations Band 1

A developer for simplicity's sake is assumed to have no financial exposure to band one deviations for the following reasons:

- 1.5% of the forecast is under 2 MW,
- Band 1 errors can be returned in kind,
- There is no financial penalty adder, and
- There are no indications of over- versus under- forecasting bias.

1.3.5.3. Forecast Error Deviations Band 2 and Band 3

Combined, these two deviations suggest a 1.9% mean forecast error rate falling in the Band 2 or 3 areas. Note that large deviations in the summer months are much less likely since the forecasted production is less. This is worthwhile remodeling when real resource information becomes available. There is no current data to support these estimates, but they are relatively modest cost components to the overall project.

A disaggregation into HLH and LLH errors is completed to the right of the main fields.

1.3.5.4. Cost Deviations Bands 1, 2, 3

Cost Deviations in band 1 are not considered; bands two and three are calculated by taking the number of forecast MWH in HLH and LLH periods and multiplying them by the appropriate percentage penalty and forecasted price.

1.3.5.5. Total Expected Generation Imbalance Charges

The total expected imbalance charges are the sum of the individual cost deviation bands exported to the ANCILLARY sheet.

1.3.6. ANCILLARY sheet

Ancillary Services are those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission System in accordance with Good Utility Practice.[xii] Ancillary Services in this analysis include:

- Scheduling, System Control and Dispatch;
- Reactive Supply and Voltage Control from Generation Sources;
- Operating Reserve – Spinning;
- Operating Reserve – Supplemental;
- Energy Imbalance; and

- Wave Balancing Service

In some cases services may be supplied by BPA (assumed here), other providers, or self-supplied. The base case uses the BPA 2010-2011 rates[2] for years one and 2 respectively, and then increased the cost at the rate of inflation in two-year increments as BPA typically performs two-year rate cases. Certain rates have historically and could in the future fluctuate differently than inflation. The model also uses a standard calendar year as opposed to a government fiscal year.

All output from this sheet is exported to the Operating Expenses and Cost of Revenue (OPEX&COR) sheet which in turn feeds the VALUE sheet for determining the value of wave power to the Developer.

Of particular note is the "Wave Balancing Service" which does not currently exist. Developers should expect a rate like this to emerge sometime along the lifecycle of the wave power business-- much as wind has already experienced. If the rate follows the wind precedent it will be large, it will be material, it will grow through time, and it will be potential source of long-term cost advantage or disadvantage.

Although the model benchmarks a mock wave integration rate against the current BPA wind integration rate, it is not included in cost or value because it will not be applicable to the first wave project installed. Near the end of the life of the project, however, and assuming the technology takes off, the first-to-market projects may or may not be rate grandfathered.

1.3.6.1. Scheduling, System Control and Dispatch

Scheduling, System Control and Dispatch Service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. This service is based on the amount of capacity installed (RESOURCE&ABSORBER sheet) applied against the rate (see above for rate source and rate inflation) to arrive at a total cost per month (far right field of cells).

1.3.6.2. Reactive Supply and Voltage Control

Reactive Supply and Voltage Control from Generation Sources Service is required to maintain voltage levels at transmission facilities within acceptable limits. In order to maintain transmission voltages, generation facilities in the Control Area are operated to produce or absorb reactive power. The Transmission Customer must purchase this service from BPA if it the generation is integrating via BPA transmission.

[2] A summary BPA transmission rate sheet can be downloaded at http://www.transmission.bpa.gov/Business/Rates/documents/TR-10_Rates_Summary_Final_Proposal_Website_Posting.pdf

The most recent BPA rate schedule did not charge for this ancillary service[xiii] and this assumption was assumed to carry forward for all future periods.

1.3.6.3. Operating Reserve – Spinning

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. Spinning Reserve Service is needed to serve load immediately in the event of a system contingency[xiv]. Spinning operating reserve is capacity which can be made available to a transmission system with ten minutes' notice and can operate continuously for at least two hours once it is brought online.

The required reserves is 3.5% of the scheduled energy from the project; this is an input cell G42. Multiplying this reserve figure by the total MWh production for the month yields the amount of reserve that must be purchased. To the right of this field is the rate input field inflated in the manner previously noted. These fields are then multiplied together to give the total cost of spinning operating reserves.

1.3.6.4. Operating Reserve – Supplemental

Operating Reserve – Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load.

The required supplemental reserves is 3.5% of the scheduled energy from the project; this is an input cell G59. Multiplying this reserve figure by the total MWh production for the month yields the amount of reserve that must be purchased. To the right of this field is the rate input field inflated in the manner previously noted. These fields are then multiplied together to give the total cost of supplemental operating reserves.

1.3.6.5. Energy Imbalance

Energy imbalance charges are calculated on and imported from the GEN IMB sheet because energy imbalance requires a greater number of assumptions and more involved modeling. Once in this sheet (far right field) the costs are summed and then exported to the OPEX&COR sheet.

1.3.6.6. Wave Balancing Service

A was noted earlier, the Wave Balancing Service and corresponding wave integration rate does not currently exist and is not figured in the base economic case for wave power, but it can be activated by inputting "Y" in cell B15 of the OPEX&COR sheet. This rate is assumed in the spreadsheet to be exactly the same as wind balancing service, and is consistent with the rate inflation methodology described and applied elsewhere. Note that the wind integration rate is actually composed of three different sub-rates:

- Regulating Reserves,
- Following Reserves, and
- Imbalance Reserves

BPA has extensive documentation on the creation and determination of these and other rates on-line.[xv] The most important of these reserves, and potentially the most volatile in the future, is the Imbalance Reserve which is the capacity counterpart to the generation imbalance energy charge.

In the workbook, the three constituent rates and associated fields below the wave balancing service fields are inputs to the calculated Wave Balancing Service Rate field. The annual grand totals for these costs in cells AW95:AW106 are exported to the OPEX&COR sheet.

1.3.7. TRANSMISSION sheet

The transmission sheet holds the assumptions for expenses related to delivering energy to the power grid.

1.3.7.1. Long-Term PTP Transmission

The model assumes that the developer will pay for one Point-to-Point (PTP) transmission leg to deliver energy to an acceptable point of delivery to the buyer. Further, it is assumed that that the reserved amount is for Firm annual transmission for the maximum amount desired for the year. These assumptions are based on the precedent that many other renewable generators subscribe to transmission in this manner because they wish to avoid the risk of Unauthorized Increase Charges[xvi] These assumptions are quite expensive and the developer and others should investigate the need for and risks associated with for firm transmission at particular sites.

Transmission costs may also be borne by the buyer and Network Transmission delivery options may also benefit projects.

The calculation for PTP costs assumes that firm transmission is purchased for the entire year, is applied to the rate, and the resulting total costs are exported to the OPEX&COR sheet.

1.3.7.2. Use-of-Facilities Charges

The TRANSMISSION sheet is where the actual payments for the Use-of-Facilities option (a Transmission rate) described in the CONNECT sheet are determined. The model assumes that the developer will make payments on the asset for as long as the generating plant is in service, but no longer. If the developer produces from the plant at any point during the year, it is assumed that the developer will pay the costs for the entire year. This assumption is subject to negotiation with the Transmission asset builder.

The OPEX&COR sheet cell B19 determines whether these Use-of-Facilities charges or Advance Funding Rate payment are used. The Advance Funding Rate is used as the base assumption.

1.3.8. OPEX&COR sheet

The operating expense and cost of revenue sheet warehouses operating expense such as salaries paid to employees, research and development costs, legal fees, accountant fees, bank charges, office supplies, utilities and rent. Depreciation, also typically an operating expense is calculated elsewhere and accounted for as an operating expense on the INCOME sheet. Cost of Revenue is the expense a company incurs in order to manufacture, create, or sell the product including the purchase price of the raw material as well as the expenses of turning it into a product. Some costs identified in the OPEX&COR sheet impact the Value of wave power to the Developer as they are direct costs to bring the generation to a saleable form. All of the expenses are part of the cost of wave power.

1.3.8.1. Cost of Revenue

There are three areas in the Cost of Revenue section: ancillary services, transmission and maintenance costs. Ancillary services and Transmission services are part of the Value to the Developer measurement and its values are passed along to the VALUE sheets; all three are pertinent to the cost of power and are part of the Income Statement (INCOME sheet).

The user can specify whether or not the individual Ancillary Services or Transmission costs should be included in cost and value calculations by selecting "Y" to include the expense or "N" to exclude the expense in cells B10:19.

Maintenance costs, including M&R, Services and direct Labor Costs are imported from the property and equipment (PROP&EQUIP) sheet, services sheet (SERVICES), and labor (PERSONNEL) sheets, respectively.

1.3.8.2. Operating Expenses

Operating expenses include Selling and Marketing, Research and Development and General and Administrative costs. All of these expenses impact the cost of power and are passed on to the Income statement; none are assigned to the value of power. Selling and Marketing and Research and Development are imported from the PERSONNEL sheet. General and Administrative is the sum of the four items immediately below it in the spreadsheet: Direct General and Administrative (from PERSONNEL sheet), Other Expenses (training, travel, etc…) which is a user defined input increased at the inflation rate, Facility costs (rent), and Utilities.

1.3.9. REVENUE sheet

The REVENUE sheet is where the income from sales of energy and attributes is calculated and ultimately passed on to other sheets for valuation (the VALUE sheet) and cost calculation (net revenue in the INCOME sheet).

1.3.9.1. Revenue Summary

The revenue summary gathers all sources of income for the project and states them as a Net Revenue number that is transferred to the INCOME sheet. The two revenue streams are from energy sales and REC sales. The energy and REC sales figures are sent to the VALUE sheet.

1.3.9.2. Monthly HLH Revenue Projections

This field imports monthly HLH price and volume data from the PRICE and RESOURCE&ABSORBER sheets and multiplies them together to yield a monthly HLH energy revenue projection.

1.3.9.3. Monthly LLH Revenue Projections

This field imports monthly LLH price and volume data from the PRICE and RESOURCE&ABSORBER sheets and multiplies them together to yield a monthly LLH energy revenue projection.

1.3.9.4. Monthly Power Revenue Projections

This field sums the above two HLH and LLH figures and then transfers the yearly sum to the Revenue Summary section above.

1.3.9.5. Monthly REC Revenue Projections

Similar to the energy projections, this field imports and multiplies REC prices and volumes to arrive at monthly and annual REC revenue figures that are transferred the revenue summary above.

1.3.9.6. Capacity Revenue

The model assumes there is no capacity value in wave power.

1.3.10. VALUE sheet

The value of wave power is expressed in two ways: the value to utility and the value to the developer. The value to the utility is the sum of the energy and REC revenues expressed as a per MWh figure. The value to the Developer is the value to the utility less the direct costs of integration and delivery of the products.

1.3.10.1. Revenue

Revenue figures are imported from the REVENUE sheet and the MWh figures are imported from the RESOURCE&ABSORBER sheet. These are in turn used as inputs in the calculations further down the VALUE sheet.

1.3.10.2. Direct Integration and Delivery Expenses

Direct Integration and Delivery expenses are imported from the OPEX&COR sheet and are used further down in the sheet to determine the Value to the Developer.

1.3.10.3. Value to Utility

The goal of the Value to Utility calculation is to arrive at a single per MWh (includes REC) contract price that takes into account the forecasted prices and the time-value of money. To accomplish this forecasted prices are discounted by the risk-free rate against a baseline year for discounting. Note that the Years Discounting row is a user-defined input and it was assumed that the first year of delivery is the undiscounted baseline year. This should be altered to correspond with any changes in the first year of delivery assumptions. It is important to leave this field blank in the years of non-delivery for the logic to work elsewhere in the sheet.

The Flat Price field is an single price input that is transferred to and discounted in the PV Flat Price field immediately below it. This discounted price is then multiplied by the volume to arrive at a discounted value for a flat-priced contract.

To actually figure out what the flat price should be, the user can either manually input values until the two figures under the Total column to the right of the fields balance or alternatively the goal-seek function can be used. To use goal seek (excel 2007) go to Data...What-If Analysis...Goal Seek to the following parameters:

Set c ell: click on cell X43
To Value: (type in the number in cell X39
By changing cell: click on cell D41

Then hit OK. The breakeven value should now appear in cell D41.

1.3.10.4. Value to Developer

The value to Developer section follows exactly the same procedures and methodologies described in the previous section with the exception that direct integration and delivery costs are subtracted from the value.

1.3.10.5. Difference between Utility and Developer

The difference between the Utility and Developer price per MWh is actually simply the average price per MWh to integrate and deliver the energy and RECs. This figure is called out separately because it is an item of interest in terms of both public policy and ultimately may be a source of competitive advantage for wave vis-a-vis other renewable technologies.

1.3.10.6. Wave Energy Premium to Block Energy

The Wave energy premium to Block Energy calculation describes the ratio of the price premium for wave energy delivered in the particular Monthly (and HLH/LLH) configuration of the resource versus the price for an identical number of MWh block of energy delivered equally over the entire year for all periods. Odd-lot liquidity is not considered in the calculation of this value. Notice that the years of partial operation have skewed percentages as delivery is a function of deployment in addition to the resource. Also note that the scheduled outage and forced outage rates also impact this calculation.

1.4. Cost of Wave Power

The following documentation describes the rest of the inputs, processes, and procedures necessary to derive a cost of wave power. Cost is broadly defined as the breakeven contract price per MWh necessary to satisfy all of the expected financial business requirements of the project.

1.4.1. PLANT CAP

The Plant Capacity sheet contains plant capital expenditure assumptions. In turn, these figures feed the Balance Sheet (BALANCE sheet) and the depreciation schedule (DEPR sheet). Renewable plant investments are assumed to benefit from the Modified Accelerated Cost Recovery System (MARCS) for depreciation and tax purposes. Many of these items could arguably be expenses rather than capitalized costs.

The top fields of the sheet are single-line summaries that bring in values either from fields below or from other sheets. The following descriptions refer jointly to the summary fields at the top of the sheet and the corresponding source fields further down the sheet.

1.4.1.1. Machinery and Equipment

Machinery and Equipment refers to the generation and absorber hardware costs of the project.

1.4.1.1.1. Absorber Units

The absorber unit costs are the delivered cost of the absorber assembly and in this case an integrated power take-off and accumulator. This is the cost per absorber unit, not the cost per kilowatt. The base case assumes a $1.5 million cost per unit (500kw), or $3000 per kilowatt. The cost per kilowatt lowers over the course of the project as economies of scale and the experience curve take hold. The change in cost over time assumptions are important for inventory, maintenance and repairs, and working capital computations in addition to the original capital expenditure calculation.

The large field imports the units deployed from the RESOURCE&ABSORBER sheet and multiplies by the dollars per unit figure to come up with the capital expenditure.

1.4.1.1.2. Power Take-Off / Accumulator

The power take-off (PTO) and accumulator is an input field for the costs of the physical accumulator(s) and power take-offs. The model assumes that there is no PTO or accumulator separate from the units in the base case.

1.4.1.1.3. Moorings

Moorings are the per-absorber unit cost of the mooring materials, not including installation. The base case assumes $125,000 per buoy with an expected life of 15 years.

1.4.1.1.4. Electrical Interconnection

Electrical interconnection is the cost to gather the power from the individual units and transmit the power to shore. The base case assumes a 138kv line extending five miles at a cost of $1.17 million per mile.

1.4.1.1.5. Advance Funding Rate (BPA Substation)

If the Advance Funding Rate is required by BPA, this is where the cost is capitalized. To activate the Advance Funding Rate go to the OPEX&COR sheet and type "N" in cell B19, the Use-of-Facilities charge. Only the Advance Funding rate or the Use-of-Facilities tariff will apply to the developer, not both.

1.4.1.1.6. Communication, Command and Control

Communication, command and control is a user defined field to capture the hardware costs of a control system for the project. This includes real-time monitoring, data gathering, system tuning and product delivery as applicable to the technology.

1.4.1.2. Services

Services are those expenses incurred by hiring third parties to install capital goods that are considered part of the goods and are therefore capitalized. These are broken down into three areas: Design, Other Contractors and Internal.

Design and Build are those expenses associated with the general contractor and its subcontractors, as applicable. Other Contractors covers direct-hired third parties not under the general contractor. Internal includes company resources and perhaps third-parties expenses associated with capitalized activity previous to the hardware Procurement and installation (e.g. licensing work performed by contractors).

1.4.1.2.1. Design and Build

The following capitalized costs are associated with a design and build contract.

1.4.1.2.1.1. Unit Assembly

Absorber installation is the cost of assembling the absorber units on land in preparation to deploy.

1.4.1.2.1.2. Absorber and Power Take-Off Installation

Absorber installation is the cost of installing the absorbers, accumulators and power take-off at sea. This figure does not include Transportation and Towing (including the crews) expense but does cover divers and technicians.

1.4.1.2.1.3. Mooring Installation

Mooring installation includes the positioning and anchoring of mooring hardware.

1.4.1.2.1.4. Electrical Interconnection

Electrical interconnection is the direct costs associated with the gathering and transmission of power to shore. the base case assumes these costs are covered in the above Machinery and Equipment section.

1.4.1.2.1.5. Design Engineering

Design engineering is performed prior to installation and is the engineering game plan taking into consideration owner specifications, materials, regulations and physical conditions.

1.4.1.2.1.6. Field Engineering

Field engineering is the cost of having engineers at unit deployment, mooring and electrical interconnection.

1.4.1.2.1.7. Commissioning

Commissioning includes expenses associated with documenting systems, training and passing the plant from construction to operations.

1.4.1.2.1.8. Communication, command and control installation

These are expenses associated with installing a third-party control system. The base case assumes that these costs are included in the Machinery and Equipment section, above.

1.4.1.2.1.9. Transportation and Towing

Transportation and towing is imported from the SERVICES sheet where all work boat chartering assumptions are warehoused. These are only costs associated with the installation of the plant and does not include regular Maintenance and Repair.

1.4.1.2.2. Other Contractors

Under other contractors are non-core activities associated with construction project oversight that probably will be outsourced by the owners, but may or may not be included in the general contractor's duties. Given that this is a first of its size project that will either be time and materials or be fixed price subject to substantial change orders, it may be prudent to have some or all of these functions aided by a party other than the general contractor depending on the owners' experience in dealing with contractors and associated cost, scope, and schedule monitoring and decisions.

We only assumed a modest quality control effort in the base case.

1.4.1.2.2.1. Project controls

Independent evaluation of the cost, scope, and schedule performance metrics during construction may be external to the

1.4.1.2.2.2. Quality control

Although there is a quality control function within the general contractor's group, given the marine environment and depending on the complexity of the equipment, it may be reasonable to have outside quality inspection.

1.4.1.2.2.3. Owner's Acceptance Review

In lieu of or in addition to external quality control it may be advantageous to have a formal owner's acceptance before the plant (or phases of the plant) are handed over from construction to operations.

1.4.1.2.2.4. Operational Readiness Review

Operational Readiness Reviews usually take place with third-party regulatory agencies before the owner is able to operate under the license. There may or may not need to be such a review for a wave project.

1.4.1.2.3. Internal

Internal cost are capitalized activities that will probably be undertaken by owner or agents of the owner. In some cases employees' time may be assigned as a depreciable capital investment rather than as an expense. The base case assumes that permitting and licensing activities are depreciable expenditures.

1.4.1.2.3.1. Permitting and Licensing

Permitting and licensing activities are among the earliest in the project and may well pre-date the time horizon in the spreadsheet. Accordingly, the cell B385 is an input field that captures prior investment that is to be carried over to this financial model. A corresponding capitalization status (Common equity, debt and carry-over Retained Earnings) should be reflected in the FUNDING sheet.

1.4.1.2.3.2. Owner's monitoring costs

Owner's monitoring costs are internal expenditures, such as salary, that needs to be accounted for separately if it going to be capitalized versus expensed.

1.4.1.2.3.3. Testing and start-up

Testing and start up costs, like monitoring costs, could be capitalized.

1.4.1.3. Other

There may be other capital expenditures not captured elsewhere that can be input in this field.

1.4.2. PERSONNEL

Employee assumptions and expenses are input and summarized in the PERSONNEL sheet. Personnel expenses are broken down into Operating Expenses and Cost of Revenue. These expenses are exported to other sheets such as OPEX&COR, finding their way ultimately to the income statement.

1.4.2.1. Personnel Operating Expenses

Personnel operating expenses include Sales and marketing, Research and Development (R&D), and General & Administrative (G&A).

1.4.2.1.1. Sales & Marketing

The base case assumes that by the time the project reaches this point that it would have a power purchase agreement behind it, so a Sales and Marketing force in this timeframe would indicate business growth external to this project and outside of the core assumptions of how the model derives costs. There are also other expenses, like Research and Development (R&D) that the policy-makers and utilities may insist be borne by the investors and excluded from this model. However, these expenses are pertinent to the Developer and its shareholders or owner.

1.4.2.1.2. Research and Development

Like Sales and Marketing, R&D is assumed to be zero in the base case.

1.4.2.1.3. General & Administration

There is assumed to be a CEO, CFO, accountant and secretary with an additional administrative person added in year three. Benefits are assumed to be 30% of salary and salaries are escalated at the inflation rate in sheet COST CAP past the first year (the blue-pink cells are functions of the green cell to the left).

1.4.2.2. Personnel Cost of Revenue

Personnel cost of revenue are expenses that are directly attributable to the creation and delivery of the product to market. Thirty percent of salary cost of benefits was assumed for operating personnel.

1.4.2.2.1. Operations Personnel

Operations personnel include one operations manager, one operations supervisor, one material and logistics coordinator and one chief engineer.

1.4.2.2.2. Hourly Personnel

The project anticipates nine hourly personnel who work on the considerable M&R work expected with the project. This would probably break sown into two or three work crews to service machinery under the supervision of the operations personnel.

1.4.2.2.3. Scheduling Personnel

Scheduling personnel are expected to be a 24x7 operation that monitors and schedules power from the project. Building this skill set does have value to the owner outside the limited scope of this project.

1.4.3. PROP&EQUIP

Property and Equipment are assets acquired to run the business that are not part of the core plant. These have different depreciation schedules and in the case of land, no depreciation at all. These items are generally exported to the Depreciation (DEPR) sheet, the Balance Sheet (BALANCE), and/or the Statement of Cash Flows (CASHFLOW).

1.4.3.1. Land Purchases

The model assumes that facilities are leased and not purchased, so there is no land acquisition assumption in the base case. The model can carry a balance for land (non-depreciable asset), but any gains or losses from the sale of land would have to be modeled separately or require alterations to this model.

The total purchases for the year are exported to the cash flow statement (CASHFLOW) and the land balance is kept on the balance sheet (BALANCE).

1.4.3.2. Office Equipment Purchases

Office equipment items are typically straight-line depreciable over 3 years. These balances are exported to the DEPR sheet. The base case assumes an escalation of costs over time punctuated with larger than normal expenditures to upgrade computer systems and other equipment.

1.4.3.3. Maintenance and Service Equipment Purchases

These are large capital goods purchases, mostly to support M&R of the plant. The base case assumes $2 million in equipment handling and repair systems depreciated over 15 years.

1.4.3.4. Warehouse Parts

Warehouse parts is a field that is used to calculate the hardware costs for maintaining the plant. This figure is the annual average product of the number of units in service times the replacement cost per unit times an assumed (5%) fixed percentage of the generating units' cost that has to be replaced each year. This is the single largest cost of revenue item and also eclipses operating expenses.

1.4.3.5. Property and Equipment (Non-Generating)

These fields add together the non-plant property and equipment balances and subtract out accumulated depreciation to provide an input to the balance sheet.

1.4.3.6. Property Plant and Equipment Summary

These imported and calculated fields hold gross and net property, plant and equipment (PP&E) calculations. The Plant and Equipment field is taken from the PLANT CAP sheet and passed to the DEPR sheet for depreciation accounting.

1.4.3.7. Plant Disposal

The model assumes that disposal costs offsets scrap value.

1.4.4. DEPR

Depreciation (DEPR) is broken down into three categories with corresponding depreciation schedules:

- Office Equipment -- 3 years straight-line
- Plant-- 6 year MACRS
- Maintenance and Service Equipment-- 15 years straight-line

1.4.4.1. Office Equipment Depreciation

Three-year depreciable office equipment figures from the PROP&EQUIP sheet are imported into this calculated field. Note that the field does *not* automatically change to accommodate different years of depreciation. Such a change requires the user to change the formulas in the imported field.

1.4.4.2. MACRS Schedule

The Modified Accelerated Cost Recovery System (MACRS)[xvii] allows the plant to be depreciated over five years at an accelerated pace. It bears repeating that the model only keeps one set of books and so depreciation and asset values are treated as they are for tax purposes and not for publically-held financial reporting purposes.

1.4.4.3. Plant Depreciation

Plant depreciation multiplies the periodic capital expenditures for the plant times the depreciation matrix to calculate an annual depreciation expense. The model assumes that the expenditures may begin being expensed in the year that they are incurred and not beginning (or accruing interest) until the plant becomes operational.

1.4.4.4. Maintenance and Service Equipment Depreciation

Maintenance and Service Depreciation is for non-plant assets that have an assumed life of 15 years. Like the MACRS schedule and the Office Equipment Depreciation, the field does *not* automatically change to accommodate different years of depreciation. Such a change requires the user to change the formulas in the imported field. The total Depreciation figure at the bottom is exported to the INCOME sheet for consideration in the income statement.

1.4.5. SERVICES

Services are work boat charters and utility expenses. Work boat charters can be cost of revenue expenses associated with M&R and plant removal or capitalized costs when the charters are for plant installation. Utilities are considered operating expenses in the base case, though some, or even most, could arguably be cost of revenue.

1.4.5.1. Work Boat Charter Expenses

The base case assumes that the during the winter boats will only be needed sporadically to tow forced-outage units to shore for repairs and back for deployment. During the maintenance season it is assumed one full-time boat will be needed to tow units to shore for maintenance (moves roughly 45 generating units both ways per month).

Day rate costs are for fully staffed large offshore workboats and are escalated at the inflation rate.

1.4.5.2. Work Boat Capitalized Charters

The model assumes two full-time boats working to install units. The number of units installed increases with time but the number of boats remains the same as the base case assumes a learning curve. Smaller figures indicate lower unit deployment rates or preparatory work just prior to deployment (e.g. mooring placement activity).

The dollar calculations are exported to the Transportation and Towing section in the PLANT CAP sheet.

1.4.5.3. Utilities

Utilities are, for example, water, sewer, power and gas. AS wan previously mentioned these could be reclassified as cost of revenue with a slight change to the model.

1.4.6. LEASES

We assume an operating lease arrangements for office space, warehouses, and dock space. Although property ownership or capital leases with right to buy the asset may be more economical, the operating lease assumption is consistent with the limited-life of the project.

The model assumes with the number of workboats employed, the maintenance schedule, employees, and the size of the warehouse and dock space that this technology is being removed annually from the water for shore M&R.

1.4.6.1. Office Space

Before warehouse and dock space is needed an interim office will be needed. Once the warehouse and dock space is secured it is assumed that the offices are on-site at the warehouse.

1.4.6.2. Warehouse and Dock Space

We assumed a 170000 square foot facility at $.90 per foot per month as the base case (10 150'x100' workspaces for maintenance plus 20000 feet for office, infrastructure and maneuvering space). This price is assumed to include adequate dock space.

1.4.7. FUNDING

The funding sheet contains financing activities with associated interest expenses and income items. It is driven by the capital structure and cost of capital assumptions in the COST CAP sheet.

Funding and the assumptions underlying it such as capital structure and corresponding rates and resulting dividend calculation are major factors in the cost of wave power. Risk sharing or amelioration in the project can radically alter these assumptions. Costs to float the issuances are not explicitly calculated in the figures and these costs may influence the number and timing of issuances.

1.4.7.1. Equity

The base case COST CAP sheet suggests a 60% equity, 40% debt capital structure. The manual funding inputs strive to maintain a 60:40 balance in *invested* capital. Note that retained earnings often becomes negative, typically the direct result of the dividend assumption and cash comes perilously close to zero in the early years.

Debt covenants and other practicalities make it unlikely that this business will pay a dividend in the early years, if ever. For modeling purposes, however, it is assumed that the dividend is paid to avoid the accumulation of sums exceeding the amount to retire debt and equity in the balance sheet and to avoid sub-performing interest earnings. Therefore although total equity including retained earnings may send the Debt to Equity ratio far above .67, in practice this will not happen. Again, this is an artifact of the model and the desire to keep only one set of books.

1.4.7.2. Debt

Debt is made up for short-term and long-term debt. It is assumed that a short term credit facility can be secured with an adequate equity investment. This facility is maintained throughout the project. When the project begins plant construction two long-term debt issuances will take place in years three and four.

1.4.7.3. Interest Rates

Short-term debt is the assumed cost of short-term borrowing, assumed here to be prime plus 1% (manually input in green cell C31). Interest on cash and cash equivalents is currently set at six-month LIBOR. Long-term debt rates are drawn from the COST CAP sheet assumptions. Note there are not forward projections to these rates which could be material, especially in light of current short-term market conditions.

1.4.7.4. Interest Expense

Interest expense simply multiplies the outstanding loans versus the applicable interest rate. The sum of interest expenses are exported to the INCOME sheet.

1.4.7.5. Interest Income

Interest income takes the weighted average cash and cash equivalents and multiplies it times the interest rate for cash and cash equivalents. This is a circular reference that can cause problems when using goal seek and other iterative functions. This feature can be enabled or disabled in Excel Options... Formulas... Enable Iterative Calculation.

1.4.7.6. Dividends and Retained Earnings

At the bottom of the sheet are calculations for dividends and retained earnings. Net income is imported from the INCOME sheet. Dividends are assumed to be the cost of equity from the COST CAP sheet times the amount of equity invested. Subtracting the dividends from the Net income yields the change in retained earnings for the period. Ending retained earnings balances are transferred to the Balance sheet.

1.4.7.7. Credit Support

The model currently assumes that there is no credit support requirements or associated cost of credit support.

1.4.7.8. Third-Party Beneficiary Reserves

The model assumes that there are no escrow accounts or other set-aside funds to cover third party impacts (e.g. environmental remediation or fishing gear losses)

1.4.8. INCENTIVES

There are three federal incentives currently considered in the model: Investment Tax Credits, Production Tax Credits and Federal Grants. Currently a project may only elect one incentive, which in the model is user-defined in cell B10. All credits are assumed in the TAXES sheet to be available for future years if they are not used immediately. INCENTIVES are not explicitly carried as deferred tax assets on the balance sheet to avoid balance sheet breakeven calculation problems in determining the cost of wave power.

Although it is unclear how long these incentives will be available, the model accommodates all three and the base case assumes that a Federal Grant is chosen because of the high capital-intensity of wave, the challenges in funding an emerging technology and the stand-alone entity base assumption. Larger entities that can use the tax credit immediately may strongly favor credits in lieu of grants because the depreciable asset base is much larger and the credits can be immediately applied against profits elsewhere in the company.

State incentives, such as the Tax Credit for Renewable Energy Equipment Manufacturers[xviii] are also available, but none were assumed in the model as they are either suited for different industries or technologies or would commit a developer to specific actions other than simply investing in the project or producing energy and/or RECs.

The State and Federal incentive landscape is continually evolving. An excellent source for this information is the Database of State Incentives for Renewable and Efficiency (DSIRE). [xix]

1.4.9. INV CREDITS

Investment Tax Credits are essentially tax vouchers for a portion of the investment made in the plant. Currently developers are entitled to 30% of invested capital though this is a user-defined percentage (cell c12). Investments are imported from the PLANT CAP sheet and multiplied by the percentage in cell c12. Credits are exported to the INCENTIVES sheet if "I" is selected in INCENTIVE sheet cell B10 and then transferred to the TAXES sheet for final calculation with taxes.

1.4.10. PRO CREDITS

Production Tax Credits arise from the production of energy and are set as a dollar value per MWh produced, in this case $21 per MWh in year 1, increased at the rate of inflation. There is talk that this incentive will be phased out through time, but there is also a strong wind lobby to keep this incentive. All other things being equal, production credits tend to be preferred over investment tax credits the higher the ratio of MWh produced to capital invested per installed kilowatt.

Production figures are imported from the RESOURCE&ABSORBER sheet. Credits are exported to the INCENTIVES sheet if "P" is selected in INCENTIVE sheet cell B10 and then transferred to the TAXES sheet for final calculation with taxes.

1.4.11. FED GRANT

The Federal Grant is a cash payment from the government that pays for a portion of the total plant capital investment. Currently this figure is 30% of capital invested, similar to the Investment Tax Credit. Grant accounting prevents the investor from taking depreciation on the portion of the asset funded by the grant, but the grant provides funds for capital investment up-front.

Investments are imported from the PLANT CAP sheet and multiplied by the percentage in cell c12. The grant figures are then exported to the INCENTIVES sheet if "G" is selected in INCENTIVE sheet cell B10 and then transferred to the PLANT CAP sheet for deduction from invested capital.

1.4.12. TAXES sheet

The taxes sheet contains all state and federal tax-related information and calculations for the project. Property, local, and other taxes and fees are not considered in the model.

1.4.12.1. Income Tax Rates and Taxes before Credits

Income tax rates are assumed to be 35% for federal taxes and 6.6% for Oregon.[xx] A separate accounting and calculation is necessary to support appropriate tax credit calculations. State taxes are passed through to the Net Taxes figure because no state credit have been identified in the model.

1.4.12.2. Production Tax Credits

Production tax credits calculations populate from the PRO CREDITS sheet if they are selected on the INCENTIVES sheet. They are assumed to be able to be carried forward indefinitely, but if they cannot be used by year 20, there is no tracked residual value.

1.4.12.3. Investment Tax Credits

Like production tax credits, investment tax credits calculations populate from the PRO CREDITS sheet if they are selected on the INCENTIVES sheet. They are assumed to be able to be carried forward indefinitely, but if they cannot be used by year 20, there is no tracked residual value.

1.4.12.4. Net Taxes

Net Taxes are calculated and passed to Income Statement.

1.4.12.5. Local taxes

The model assumes there are no local taxes on the project.

1.4.13. WORKING CAPITAL

Working capital is composed of current assets and current liabilities, represents operating liquidity available to a business, and is considered a part of operating capital. In this section the spreadsheet accounts for non-cash and non-financial short-term assets and liabilities; namely accounts receivable, inventory and accounts payable. All three of these items directly impact the statement of cash flows and the balance sheet.

1.4.13.1. Accounts Receivable

Accounts receivable are sales made for which the Developer has not yet received cash payments. Although the sale has been recognized in the income statement and earnings it is not a cash item and is listed separately on the balance sheet from cash.

The model base case assumes a 8.3% (or 1/12) of a year's sales as receivables. If the year-end is December 31, one would expect this number to be higher as a direct calculation against a high-delivery month would be larger than the annual average. However, company accounting periods can be determined by the company; this broad assumption can be changed when a project operating and tax year is established.

1.4.13.2. Inventory

Inventory is calculated as a fraction of the total number of parts during the year needed to service the equipment. As time goes on it is expected that experience will allow closer to a just-in-time inventory management system which is why the turnover figure in row 19 increases with time.

Again, depending on the time of year (e.g. summer maintenance season versus winter) these figures and the accounting assumptions could change substantially.

1.4.13.3. Accounts Payable and Accrued Expenses

Accounts payable assumes the same 30-day cycle against annual total expenses from sheet OPEX&COR. The Accounts receivable modeling comments also apply to these assumptions.

1.4.14. INCOME

The income statement draws values from various sheets to calculate the earnings of the enterprise.

There is not a worksheet for extraordinary items in the workbook, but there is a user-defined field for entry in the INCOME sheet. Keep in mind that if this field is populated it may require additional information input elsewhere in the workbook to be reflected properly in the statement of cash flows and balance sheet.

1.4.15. CASHFLOW

The cash flow sheet is a simple indirect method calculation of the statement of cash flows which begins with Net earnings and applies cash adjustments by activity class.

The two Financing Activities that impact cost the most are the Federal Grant and Dividends. The federal grant is a source of cash that only appears if the grant is selected ("G") in sheet INCENTIVES cell B10. The dividends are a large use of funds and any efforts to lower the need to equity fund the project will greatly help cost.

1.4.16. BALANCE

The balance sheet is a standard financial balance sheet with assets, liabilities and owner's equity. All of the figures are driven by other sheets' calculations. Note that in the base case owner's equity may be substantially negative because when valuing wave power (in the low $100's per MWh) the costs overwhelm the revenues causing negative equity builds over time. In the cost breakeven, bear in mind that the user is forcing the model to find the contract price such that the final year's balance sheet equals zero, which translates into a higher contract price.

1.4.17. Cost Model Procedures

The cost model differs from the value model in a couple of ways. First, all REC prices in sheet PRICES cells C118:V118 have been set to zero-- the breakeven cost in this model is assumed to be for both the RECs and Energy prices in PRICES sheet cell C8. This assumption can be changed by the user. Note that sheet PRICES cells D8:V8 all read from cell C8. This permits the user to calculate a nominal price per MWh using the goal seek tool (Data...What-if-Analysis...Goal Seek. The goal seek setting should be as follows:

Set cell: <BALANCE sheet, cell 31>
To value: 0
By changing cell: <PRICES sheet, cell C8>

On some machines the iteration calculation for the circular reference in sheet FUNDING cells C42:V42 interferes with the goal seek function. in this event, the user must manually interpolate prices until a near-zero ending balance sheet solution is found.

2. Strategies

Strategies are general plans of actions designed to bridge the gap between cost and value. There are many kinds of strategies, some focused inwards towards the developer, others focusing on the market and others probing regulatory opportunities. The following list is not exhaustive nor explicit but is designed to provide some initial thoughts and a range of opportunities for developers, utilities and policymakers to explore.

2.1. REC Multipliers and Certainty

Developers and utilities could both pursue favorable REC calculations from Wave. Solar has already made headway into this realm by receiving two RECs for every one MWh produced. If regulatory bodies would grant RECs on the basis of a percentage of nameplate capacity, thereby taking out year-to-year variability of the resource (and machine performance), this would be of great value to the utilities (and therefore developers) who dislike short squeezes.

2.2. Large Company Alliance

Probably not an initial favorite of the Developers who have labored long and hard, partnering with or selling to someone large can jumpstart the wave industry which is behind both solar and wind. Partnering may also help contract execution, lower costs by gaining access to in-house manufacturing, and perhaps lower the cost of capital.

2.3. Advertising

Enhancing public perceptions helps manage political capital requirements and regulatory margin. In some cases, actions or policies that may otherwise consume political capital may actually create political capital.

2.4. Asymmetric Valuations

Asymmetric valuations are the basis of trade. When two parties value something differently there can often be an opportunity for both parties to win economically and for one party to select the counterparty who offers the best transactions terms. For example, one utility may value wave greater than wind for long-term strategic integration cost reasons, or a local utility may value the regional employment benefits from a project more than an inland utility.

2.5. Helping the Helpers

Part of the early success of wave power will be the ability of developers to receive aid from third parties without spending much money. Sometimes parties want to help but are prevented from doing so either by legislative or regulatory prohibitions or for lack of resources. For example, government agencies are forbidden to lobby, but developers are not. Acquiring money for an agency may make a pre-planned resource placement become reality.

2.6. Integrated versus Un-integrated

The price to integrate power into the grid may be different for different parties affecting the deal price and how the product is delivered. For example, if a plant can be combined with other generating assets or load profiles there may integration cost financial opportunities.

2.7. Capacity Values

The base model assumes there is not any capacity value to wave power. If the accumulator or some other technology allows the dispatch of wave power, additional revenue streams may be available.

2.8. Capital Structure

Capital structure plays a major role in the cost of wave power. Optimizing debt and equity and finding the most advantageous transaction and partnering structures will consume a great deal of developers' time as it is one of the major drivers to the cost of wave power.

2.9. Federal Loans

Federal loan can come in at least two forms: government issued bonds or government guaranteed bonds. In the former, the government may actually pay the debt service to the debt holder in the form of federal tax credit coupons or cash. In the latter, the government essentially provides a letter of credit for the bonds, thereby making them AAA with a correspondingly low effective interest rate. This is a game-changing strategy that also influences capital structure / leverage.

2.10. Wave Customization

Developers and utilities may seek special treatment for wave power because of its unique features. For example, firm transmission rate relief may be in order for non-peak months when the asset is undergoing maintenance and the resource is small (see 3.2.9).

2.11. Market Timing

When a developer chooses to enter a forward sales contract may substantially alter the value of wave power to the developer and utilities. Currently it can be argued that market prices of power are somewhat depressed due to wind penetration and REC prices have not yet reached price equilibrium because the renewable portfolio standards are not yet in effect. The value spread between wave and wind should also be constantly monitored and could be a basis for market timing. That said, market timing in energy is much like timing the stock market; prices may go up or they may go down. Even so, getting the timing right can be the difference between executing a transaction and being sidelined.

2.12. Integration Optimization

There are opportunities to lower costs to integrate the resource and avoid ancillary services and perhaps even some transmission charges. Wind is already trailblazing this path. For instance, a wave developer may choose to buy less firm transmission depending on the frequency that extremely high generation states actually happen coupled with the ability of the owner to forecast generation well and pick up non-firm transmission. There are definite cost savings in this strategy, but there is a corresponding risk of unauthorized increase charges.

2.13. Off Balance Sheet Financing

Strategies can also be implemented that require less cash investment up-front. One example that is explicitly modeled is getting access to the Use of Facilities rate (and have a large portion deemed to be for the grid as opposed to the project) as opposed to the Advance Funding Rate.

3. Report and Model Support

There are no arrangements for model or report updating or support past delivery of the product. However, feedback and general questions can be directed to: Baxter A. Gillette, General Manager, Energy Focused Resources, 713-417-1969 or bagillette@energyfr.com.

There is a circular reference in the model for determining interest income in sheet FUNDING cells C42:V42. This formula can cause problems when the breakeven calculation for . This feature can be enabled or disabled in Excel Options... Formulas... Enable Iterative Calculation.

[i] Harper, John, *Debt Financing for Wind Projects,* IPED Financing Wind Power Conference, July, 2007: 9.
[ii] http://finance.yahoo.com/bonds/composite_bond_rates
[iii] Based on Yahoo Financial and Reuters website information.
[iv] Jeremy J. Seigel, *Stocks for the Long Run*, 3rd ed. (New York: McGraw-Hill, 2002).
[v] http://finance.wharton.upenn.edu/~acmack/Chapter_09_app.pdf
[vi]*Bonneville Power Administration 2008 Annual Report*,
http://www.bpa.gov/corporate/Finance/A_Report/08/AR2008.pdf, p. 51.
[vii] http://www.usinflationcalculator.com/inflation/current-inflation-rates/
[viii] www.ndbc.noaa.gov/station_history.php?station=46029
[ix] For a NERC Holiday calendar, see: http://www.nymex.com/pjm_fut_calcvcon.aspx#2
[x] King, Jeffrey et. al, *Draft Northwest Sixth Power Plan,* Power and Conservation Council, Sept. 3 2009.
http://www.nwcouncil.org/energy/powerplan/6/DraftSixthPowerPlan_090309.pdf

[xi] *2010 Transmission and Ancillary Service Rate Schedules* , Bonneville Power Administration Transmission Services, October 1, 2009: 47-50. http://www.transmission.bpa.gov/Business/Rates/documents/TR-10-A-BPA-02_Final_Rate_Schedules_to_Print.doc
[xii] ibid, 97.
[xiii] *First Quarter FY 2010 Formula Rate Summary*, , Bonneville Power Administration Transmission Services
http://www.transmission.bpa.gov/Business/Rates/documents/Formula_Rate_Summary_Q1FY10.pdf
[xiv] *2010 Transmission and Ancillary Service Rate Schedules* , Bonneville Power Administration Transmission Services, October 1, 2009: 104. http://www.transmission.bpa.gov/Business/Rates/documents/TR-10-A-BPA-02_Final_Rate_Schedules_to_Print.doc
[xv] Administrator's Final Record of Decision: 2010 Wholesale Power and Transmission Rate Adjustment Proceeding (BPA-10), Bonneville Power Administration, July, 2009.
http://www.transmission.bpa.gov/Business/Rates/documents/WEB_WP-10-A-02_TR-10-A-02.pdf
[xvi] *2010 Transmission and Ancillary Service Rate Schedules* , Bonneville Power Administration Transmission Services, October 1, 2009: 91. http://www.transmission.bpa.gov/Business/Rates/documents/TR-10-A-BPA-02_Final_Rate_Schedules_to_Print.doc
[xvii] http://www.irs.gov/publications/p946/ch04.html
[xviii] http://www.dsireusa.org/incentives/incentive.cfm?Incentive_Code=OR107F&re=1&ee=1
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[xx] Previsic, Mirko, Omar Siddiqui and Roger Bedard, "Economic Assessment Methodology for Offshore Wave Power Plants", Electric Power Research Institute, 2004: 9.