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System Level Design, Performance and Costs – Oregon State Offshore Wave Power Plant

Report:	E2I EPRI Global – WP - 006 – OR Rev 1
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Date:	November 30, 2004

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1 Introduction and Summary

This document describes the results of the system level design, performance and cost study for both a feasibility demonstration pilot plant and a commercial size offshore wave power plant installed off the coast of Oregon. For purposes of this point design study, the Oregon stakeholders selected the Ocean Power Delivery (OPD) Pelamis wave energy conversion (WEC) device, Coos Bay for fabrication of the device, grid connection at the Gardiner substation in Douglas County and a deployment site approximately 5 km due west of the substation at a water depth of 60 meters. The study was carried out using the methodology and standards established in the Design Methodology Report (Reference 1), the Power Production Performance Methodology Report (Reference 2) and the Cost Estimate and Economics Assessment Methodology Report (Reference 3).

A pilot scale wave power plant using a single Pelamis Wave Energy Conversion device was evaluated. The yearly electrical energy produced and delivered to the grid interconnection is estimated to be 1,001 MWh at the selected deployment site and would cost $4.7 million to build ($3.1 million after the Oregon 25% and Federal 10% tax credit). This cost reflects only the capital needed to purchase a single Pelamis unit, the construction costs to build it and the grid interconnection cost. Therefore, it represents the installed capital cost needed to evaluate and test a single Pelamis WEC system, but does not include the following elements:

- Detailed Design, Permitting and Construction financing
- Yearly O&M Costs
- Test and Evaluation

A commercial scale wave power plant was also evaluated to establish a base case from which comparisons to other renewable energy systems can be made. The yearly electrical energy produced and delivered to bus bar is estimated to be 1,669 MWh/year for each Pelamis WEC device. In order to meet the target output of 300,000 MWh/year a total of 180 Pelamis WEC devices are required. The elements of cost and economics (with cost in 2004$) are:

- Total Plant Investment = $235 million
- Annual O&M Cost = $10.9 million; 10-year Refit Cost = $23.5 million
- Levelized Cost of Electricity (COE)[1] = 11.6 (Nominal) 9.7 (Real) cents/kWh
- Internal Rate of Return (IRR) = No IRR based on industrial electricity sell price

In order to compare offshore wave power economics to shore based wind, which reached a installed capacity base of about 40,000 MW in 2004, industry standard learning curves were applied. The results indicate that, even with worst-case wave cost estimate assumptions, the

[1] For the first 90 MW plant assuming a regulated utility generator owner, 20 year plant life and other assumptions documented in Reference 3

economics of wave power compares favorable to wind power at all equal cumulative production levels.

Offshore wave energy electricity generation is a new and emerging technology. The first time electricity was provided to the electrical grid from an offshore wave power plant occurred in early August, 2004 by the full scale preproduction OPD Pelamis prototype in the UK. Many important questions about the application of offshore wave energy to electricity generation remain to be answered, such as:

- There is not a single wave power technology. It is unclear at present what type of technology will yield optimal economics. It is also unclear at present at which size these technologies will yield optimal economics.
- Given a device type and rating, what capacity factor is optimal for a given site?
- Will the installed cost of wave energy conversion devices realize their potential of being much less expensive per COE than solar or wind?
- Will the performance, reliability and cost projections be realized in practice once wave energy devices are deployed and tested?

E2I EPRI Global makes the following specific recommendations to the Oregon State Electricity Stakeholders:

1. Encourage the ongoing R&D at universities such as Oregon State University
2. Coordinate efforts to attract a pilot feasibility demonstration wave energy system project to the Oregon coast
3. Now that the Douglas County pilot demonstration plant project definition study is complete and a compelling case has been made for investing in wave energy in Oregon, proceed to the next phase of the Project

   If this recommendation cannot be implemented at this time (due to lack of funding or other reason), E2I EPRI Global recommends that the momentum built up in Phase 1 be sustained in order to bridge the gap until Phase II can start by funding what we will call Phase 1.5 with the following tasks:

   a. Tracking potential funding sources
   b. Tracking wave energy test and evaluation projects overseas (primarily in the UK, Portugal and Australia) and in Hawaii
   c. Tracking status and efforts of the permitting process for new wave projects
   d. Track and assess new wave energy devices
   e. Establish a working group for the establishment of a permanent wave energy testing facility in the U.S.

4. Build collaboration with other states with common goals in offshore wave energy.

In order to stimulate the growth of ocean energy technology in the United States and to address and answer the techno-economic challenges, we recommend the following take place:

- Federal and state recognition of ocean energy as a renewable resource and that expansion of an ocean energy industry in the U.S. is a vital national priority
- Creation of an ocean energy program within the Department of Energy's Energy Efficiency and Renewable Energy division
- DOE works with the government of Canada on an integrated bi-lateral ocean energy strategy.
- The process for licensing, leasing, and permitting renewable energy facilities in U.S. waters must be streamlined
- Provision of production tax credits, renewable energy credits, and other incentives to spur private investment in Ocean Energy technologies and projects.
- Provision of adequate federal funding for ocean energy R&D and demonstration projects.
- Ensuring that the public receives a fair return from the use of ocean energy resources and that development rights are allocated through an open, transparent process that takes into account state, local, and public concerns.

2 Site Selection

The Oregon state stakeholders selected Douglas County as an area for locating an offshore wave power plant. Fabrication would be performed in Coos Bay, Gardiner or Reedsport and the grid interconnection would be at the Gardiner Substation. The Gardiner substation has an unused transformer (probably due to the International Paper load no longer being active). There is also surplus capacity in the 115 kV segment to Tahkenitch (the nearest connection to a 230 kV line).

The Tahkenitch substation, also in Douglas County, shown in Figure 1, has sufficient capacity to handle additional load. Bonneville Power Administration (BPA) carried out a preliminary power flow study indicating that the transmission in the vicinity of Gardiner should be able to handle up to 100 MW.

A paper mill owned by International Paper is located next to the Gardiner substation and has an effluent pipe going from the paper mill out in the ocean. This presents a unique easement to land the power cable to shore. This 30 inch diameter pipe could be used to house the power cable from the substation into the ocean thus eliminating many of the landfall and grid interconnection issues. An agreement with International Paper would need to be in place to use the pipe for this purpose.

Relevant Site Parameters

Water Depth at Deployment Site:	60m
Effluent Pipe Length:	5km
Subsea Cable Burial Length:	2.5km
Total Cable Length Required:	7.5km
Distance to Shore:	3.5km
Ocean Floor Sediments:	Sand and/or Mud
Transit Distance to Reedsport for O&M:	25km

The following (Figure 1) map shows the local site. #1 shows the location of the Gardiner substation, from where the cable is laid in the effluent pipe to #2, the outfall of the pipe. From the outfall (#2) to the deployment site (#3) the sub-sea cable is buried into the seafloor sediments. The deployment site is at the 60m water depth contour line. Figure 2 shows an enlargement of the Gardiner substation area (an enlargement of area #1 in Figure 1) and the connection to the Tahkenitch substation.

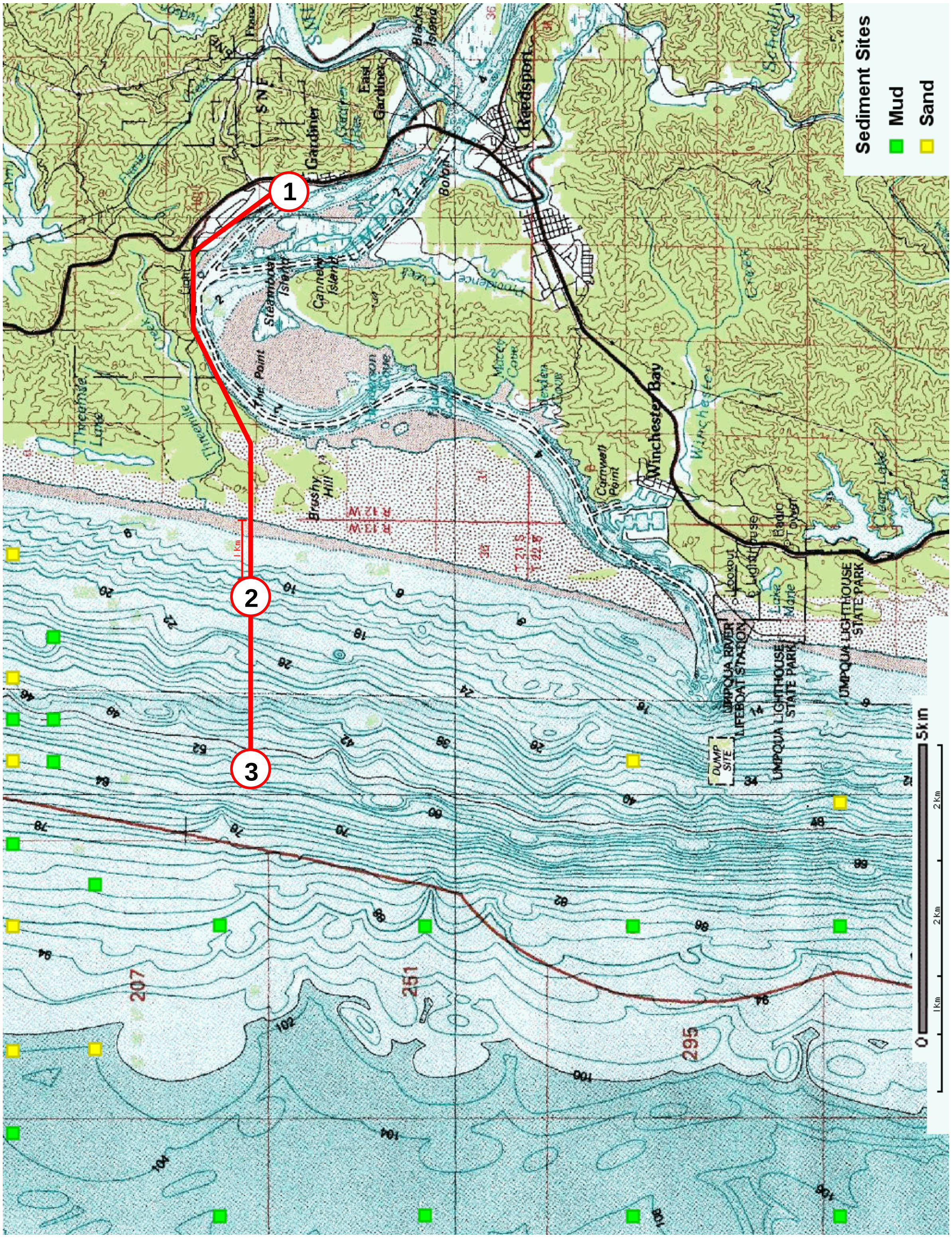

Figure 1: Local Site Map showing Bathymetry Contour Lines (in meters), Seabed Sediments and Grid Interconnection Site

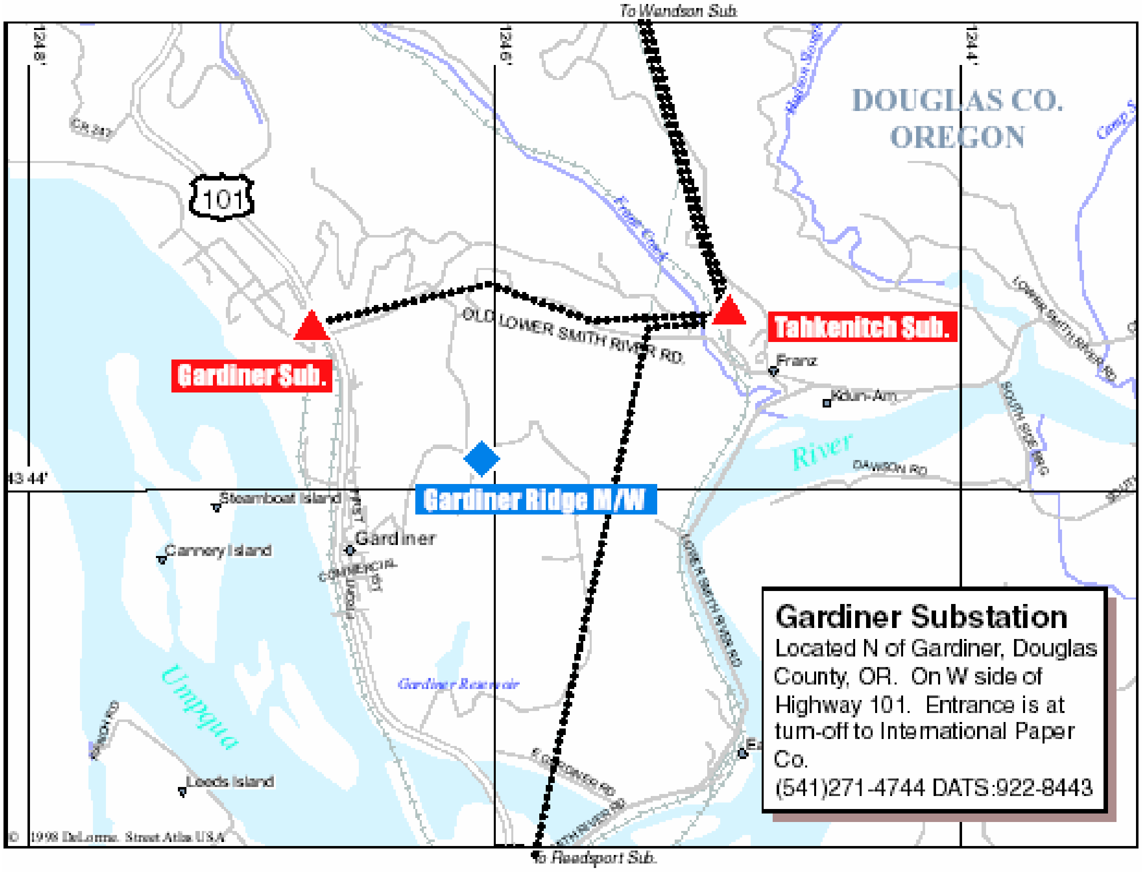

Figure 2. Gardiner Substation and Interconnection with BPA grid (Enlargement of Area #1 in Figure 1)

As shown on Figure 1, the deployment site closest to the grid interconnection point in 50m - 60m water depth will likely feature sand and mud sediments, which is ideal for the type of embedment anchors used by the Pelamis mooring system. Detailed bathymetry and geotechnical assessments will need to be carried out in a detailed design and engineering phase. Special attention will need to be paid to identify potential obstacles such as large rock formations in the cable route and at the deployment location. This is accomplished by using a combination of side scan radar, sub-bottom profiler, local dives and sediment sampling.

3 Wave Energy Resource Data

In order to characterize the wave resource at the proposed site, the Coquille River CDIP 037 wave measurement buoy was chosen to obtain wave data from. The water depth at the measurement buoy location is the same as that at the deployment site for the Pelamis. Below are some key results of the reference measurement station and characterization of the wave climate. We would not expect to see any difference in the wave resource between the location of the reference measurement buoy and the Pelamis wave energy conversion device. Figure 3 shows the average monthly wave energy power flux (in kW/meter). Scatter tables for the wave energy resource were created for each month and used to estimate the power production of Pelamis as described in Section 6.

Measurement buoy:	CDIP 037
Station Name:	Coquille River
Water depth:	64 m
Coordinates:	43° 06.8’ N 124° 30.8’ W
Data availability:	12 years (1984 – 1996)
Maximum Hs[2] recorded:	7.8m
Maximum Tp[3] recorded:	15.06 s
Estimated Single Wave Extreme Event:	15m

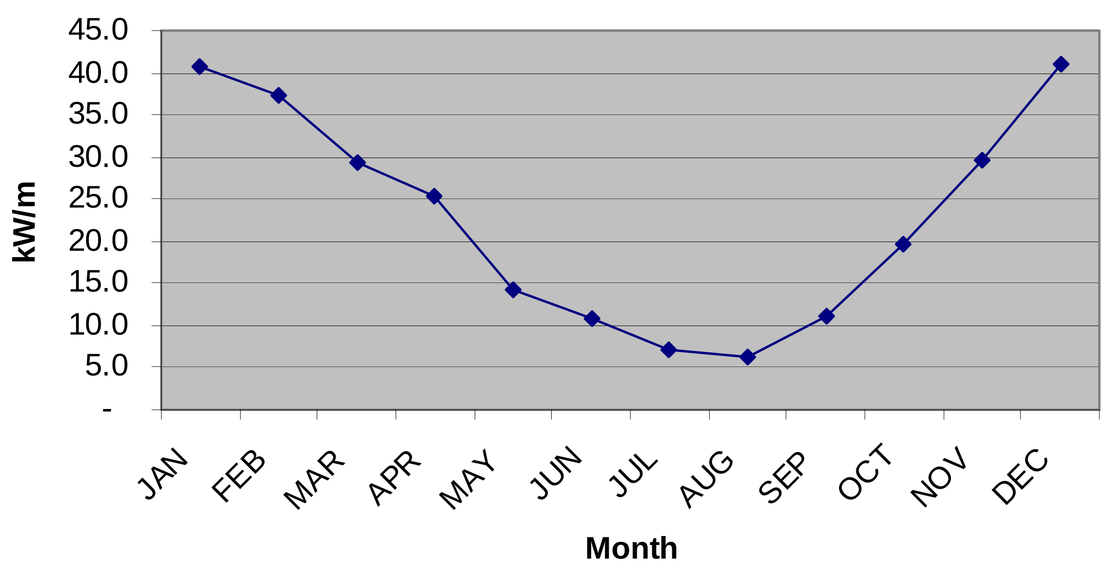

Figure 3: Monthly Average Wave Power Flux (kW/m)

[2] Hs = Significant Wave height
[3] Tp = Peak Wave Period

4 The Technologies

The WEC device chosen for the Oregon point design is the Pelamis from Ocean Power Delivery (OPD). The device consists of a total of 4 cylindrical steel sections, which are connected together by 3 hydraulic power conversion modules (PCM). Total length of the device is 120m and device diameter is 4.6m. Figure 4 shows the device being tested off the Scottish coast. Individual units are arranged in wave farms to meet specific energy demands in a particular site as illustrated in Figure 5.

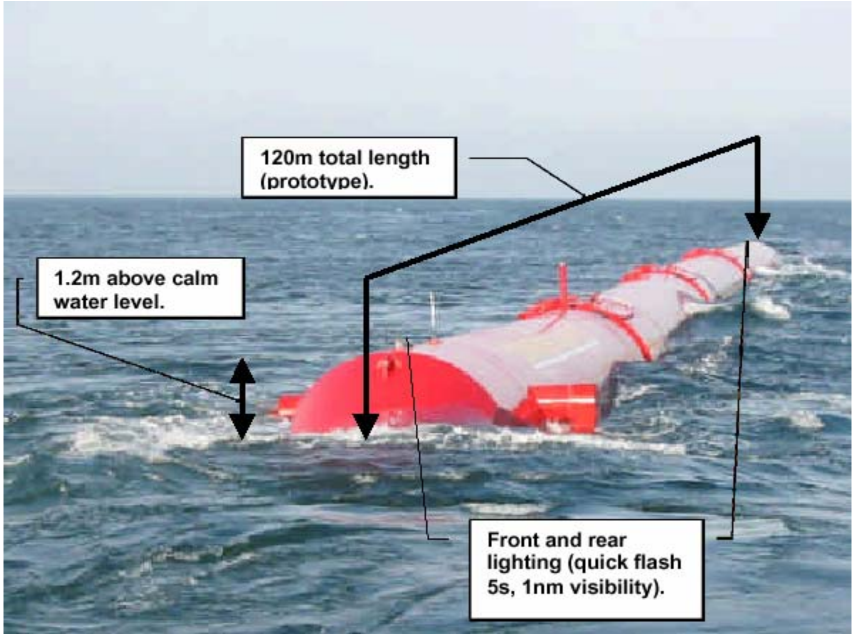

Figure 4: Pelamis pre-production prototype undergoing sea-trials

Figure 5: A Typical Pelamis wave farm

The following sections provide a high level overview of the different subsystems that are device specific. Subsystems covered include the power conversion modules (PCM), the structural steel sections and the mooring system. The summary table below shows the key specifications of the Pelamis and Figure 6 shows the power conversion train..

Table 1: Pelamis Device Specifications

Structure	
Overall Length	123 m
Diameter	4.6m
Displacement	700 tons
Nose	5m long conical drooped
Power Take Off	3 independent PCM's
Total Steel Weight	380 tons
Power Conversion Module (PCM)	
Power Take Off	4 x hydraulic rams (2 heave, 2 sway)
Ram Speed	0 – 0.1 m/s
Power Smoothing Storage	High pressure Accumulators
Working Pressure	100 – 350 bars
Power Conversion	2 x variable displacement motors
Generator	2 x 125kW
Generator speed	1500 rpm
Power	
Rated Power	750kW
Generator Type	Asynchronous
System Voltage	3-phase, 415/690VAC 50/60Hz
Transformer	950kVA step up to required voltage
Site Mooring	
Water depth	> 50m
Current Speed	< 1 knot
Mooring Type	Compliant slack moored

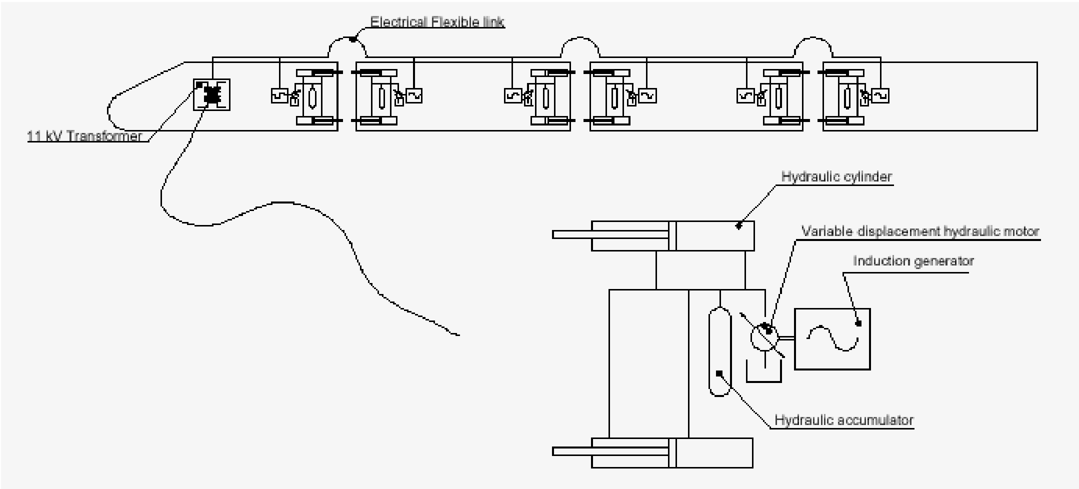

Figure 6: Pelamis Power Conversion Train

The Power Conversion Module (PCM)

As illustrated in Figure 6, a total of 3 power conversion modules (PCM's) connect the 4 individual steel tubes forming a Pelamis device. Each PCM illustrated in Figure 7 contains a heave and sway joint. The modular power-pack is housed in a second fully sealed compartment behind the ram bay so that in the event of seal failure only the hydraulic rams are immersed. Access to all system components is via a hatch in the top of the power conversion module. Maximum individual component weight is less than 3 tons to allow replacement using light lifting equipment.

The wave-induced motion of each joint is resisted by sets of hydraulic rams configured as pumps. These pump oil into smoothing accumulators which then drain at a constant rate through a hydraulic motor coupled to an electrical generator. The accumulators are sized to allow continuous, smooth output across wave groups. An oil-to-water heat exchanger is included to dump excess power in large seas and provide the necessary thermal load in the event of loss of the grid. Overall power conversion efficiency ranges from around 70% at low power levels to over 80% at full capacity. Each of the three generator sets are linked by a common 690V, 3 phase 'bus' running the length of the device. A single transformer is used to step-up the voltage to an appropriate level for transmission to shore. High Voltage power is fed to the sea bed by a single flexible umbilical cable, then to shore via a conventional sub-sea cable.

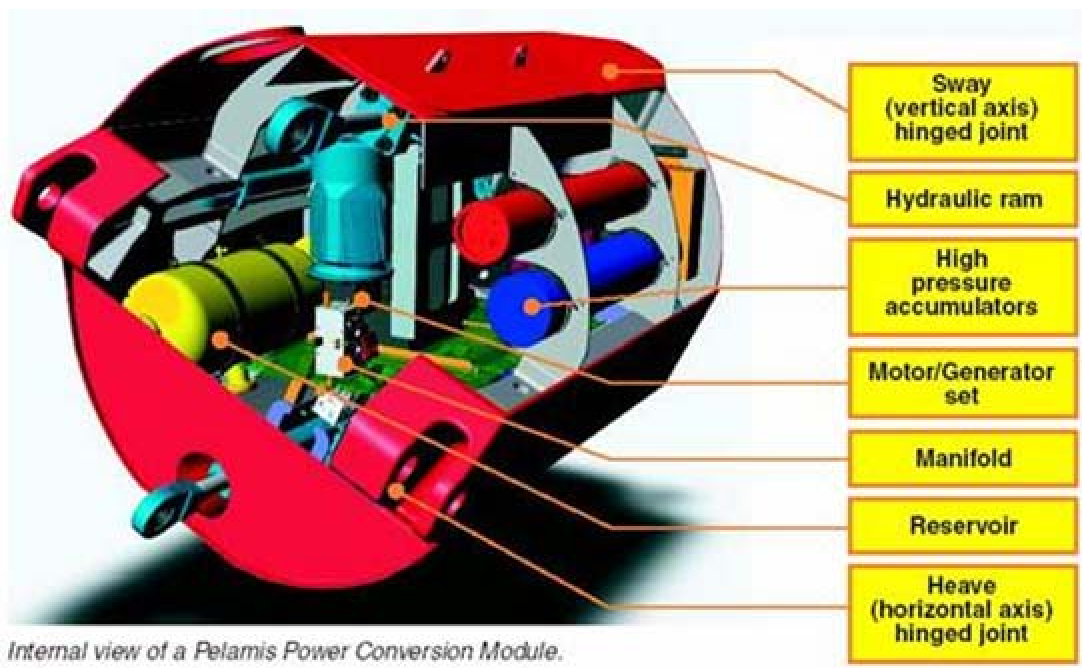

Figure 7: Internal View of the Pelamis PCM

Tubular Steel Sections

There are a total of 4 tubular steel sections, which are the main structural elements of the device. Each steel section is 25m long and weighs roughly 70tons. The main tube sections are manufactured in segments using steel plates that are rolled into shape as shown in Figure 8. Once formed, individual sections are welded together to form a segment. This manufacturing process is extensively, used in the wind industry to manufacture wind turbine towers. The process can be automated and lends itself well to cost reduction.

Cast end caps on the steel tubes incorporate hinges, which then interconnect to the Power Conversion Modules. In order to properly ballast the device, sand is added.

Alternative construction materials were evaluated under a contract by the Department of Trade and Industry. Materials analyzed and compared to each other were steel, pre-tensioned concrete and GRP (filament wound composite). Out of the 3 options, concrete emerged as the preferred option (Reference 5).

Figure 8: Manufacturing Steel Tubular Sections

Mooring System

The mooring arrangement of Pelamis needs to be designed specifically for the site conditions. Similar to a wind turbine foundation, which needs to be type approved, the Pelamis mooring system needs to be designed by OPD and adapted to specific site conditions. Survival conditions, maximum current velocity, water depth, seafloor soil densities and other factors will need to be considered in a detailed design phase.

For the purpose of this project, the reference mooring system used for Ocean Power Delivery prototype testing was used to establish a costing base case as shown in Figure 9.

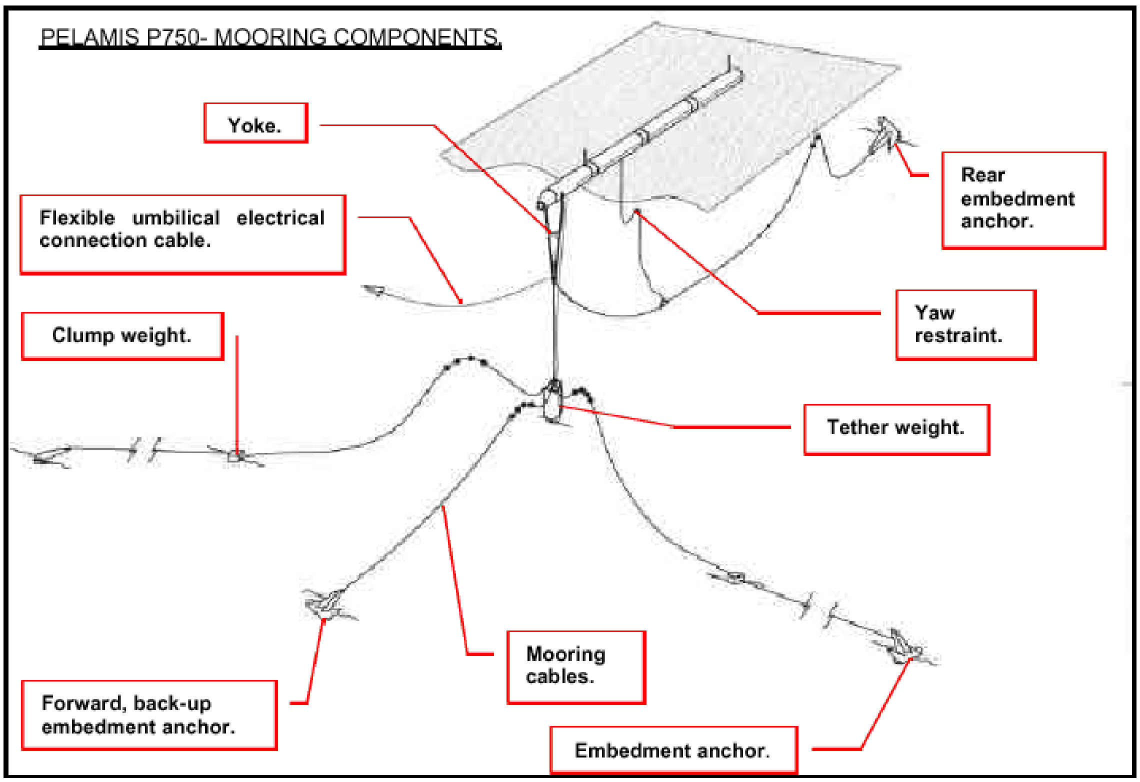

Figure 9: Mooring Arrangement of Pelamis

As shown in Figure 9, the Pelamis mooring system is a catenary type mooring using a combination of steel wire, chain, dead weights and embedment anchors.

The following four photographs of Figure 10 show some of the individual mooring elements in an assembly yard to provide the reader with an understanding of the size of these individual components.


Embedment anchor.


Clump weight.


Mooring cable.


Tether weight.

Figure 10: Mooring Components

Electrical Interconnection & Communication

Each Pelamis device houses a step-up transformer to increase the voltage from generator voltage to a suitable wave farm interconnection voltage. The choice of the voltage level is driven by the grid interconnection requirements and the wave farm electrical interconnection design. A flexible riser cable is connecting the Pelamis to a junction box, sitting on the ocean floor. If multiple devices are connected together, they are daisy-chained by a jumper cable which runs from one device to the next. Only at certain strong-points the electrical cable is then brought to the ocean floor. This approach reduces the number of riser cables required and makes the cabling more accessible for maintenance from the surface. Riser and jumper cables undergo a large number of cyclic loadings and it is likely that they will need to be replaced after 10 years of operation.

The cables used are 3-phase cables with a fiber core. This fiber core is used to establish reliable communication between the devices and a shore-based supervisory system. Remote diagnostic and device management features are important from an O&M stand-point as it allows to pin-point specific issues or failures on each Pelamis unit, reducing the physical intervention requirements on the device and optimizing operational activities. Operational activities offshore are expensive and minimizing such intervention is a critical component of any operational strategy in this harsh environment. A wireless link is used as a back-up in the event that primary communication fails.

Subsea Cabling

Umbilical cables to connect offshore wave farms to shore are currently being used in the offshore oil & gas industry and for the inter-connection of different locations or entire islands. In order to make them suitable for in-ocean use, they are equipped with water-tight insulation and additional armor, which protects the cables from the harsh ocean environment and the high stress levels experienced during the cable laying operation. Submersible power cables are vulnerable to damage and need to be buried into soft sediments on the ocean floor. While traditionally, sub-sea cables have been oil-insulated, recent offshore wind projects in Europe indicate that environmental risks prohibit the use of such cables in the sensitive coastal environment. XLPE insulations have proven to be an excellent alternative, having no such potential hazards associated with its operation. Figure 11 shows the cross-sections of armored XLPE insulated submersible cables.

Figure 11: Armored submarine cables

For this project, 3 phase cables with double armor and a fiber core are being used. The fiber core allows data transmission between the Pelamis units and an operator station on shore. In order to protect the cable properly from damage such as an anchor of a fishing boat, the cable is buried into soft sediments along a predetermined route. If there are ocean floor portions with a hard bottom, the cable will have to be protected by sections of protective steel pipe, which is secured by rock bolts.

An important part of bringing power back to shore is the cable landing. Existing easements should be used, such as the easement associated with the existing effluent pipe at the International Paper facility. If they do not exist, directional drilling is the method with the least impact on the environment. Directional drilling is a well established method to land such cables from the shoreline into the ocean and has been used quite extensively to land fiber optic cables on shore.

Onshore Cabling and Grid Interconnection

Traditional overland transmission is used to transmit power from the shoreline to a suitable grid interconnection point. Grid interconnection requirements are driven by local utility requirements. At the very least, breaker circuits need to be installed to protect the grid infrastructure from system faults.

Procurement and Manufacturing

For the single-module Pelamis pilot plant, it was assumed that the 3 Power Conversion Modules are procured from Ocean Power Delivery (OPD) and shipped from the UK to Oregon and that the structural steel sections are built locally in an appropriate shipyard. A number of shipyards exist in Reedsport and Coos Bay, which are capable of constructing the larger steel sections. Figure 12 shows the Pelamis prototype under construction in Scotland. The picture on the left shows a hydraulic ram being mounted in one of the Power Conversion Modules. The picture on the right shows the large tubular steel sections of the Pelamis being completed.

Figure 12: Manufacturing the Pelamis

Mooring components such as wire, chain and the various anchor components will be purchased from local manufacturers and assembled in a local staging site before deployment. Sub-sea cables, circuit breakers etc. will also be purchased from US based manufacturers.

At the commercial scale envisioned, it will make economic sense to establish local manufacturing facilities for the Power Conversion Modules (PCM's). A number of capable manufacturing facilities exist in Gardiner/Reedsport and Coos Bay, which would be able to build and test these modules. From a logistics and cost perspective it does not matter where these devices are being manufactured along the Oregon coast.

Coos Bay and Reedsport have also adequate infrastructure in place to carry out annual overhauls and 10-year refits, which will be required to replace major subsystems.

The establishment of local manufacturing capabilities will allow for a large amount of US content in the devices and bring benefits to the local economy.

Installation Activities

Installation and operational offshore activities require special equipment such as anchor handler vessels, barges and heavy uplift cranes. In order to understand the offshore installation and removal activities and their impacts on cost, detailed process outlines were created to be able to estimate associated resource requirements. Results were verified with Ocean Power Delivery who deployed a prototype device this year, local offshore operators in Oregon and Sea Engineering Hawaii who managed the installation of Ocean Power Technologies Power Buoy in Hawaii. The major installation activities for both pilot demonstration plant and commercial wave farm are:

1. Pulling Power Cables through existing Effluent Line and grid interconnection
2. Installation of sub-sea cables
3. Installation of Mooring System
4. Commissioning and Deployment of Pelamis

Offshore handling requirements were established based on technical specifications supplied by Ocean Power Delivery. Figure 13 below shows the anchor handler vessel used for the installation of the prototype in the UK. It is a standard vessel used in the UK offshore Oil & Gas industry. After querying offshore operators on the US west coast and Hawaii, it became apparent, that such equipment will not be available to a demonstration project. As a result, installation activities had to be adapted to be carried out on a barge, pulled by an offshore tug.

For the commercial plant, it proved to be cost effective to include an AHATS class vessel in the project cost and hire dedicated staff to carry out operational activities. Figure 14 shows the prototype Pelamis being towed to its first deployment site off the coast of Scotland.

Figure 13: AHATS class vessel used for prototype installation in UK

Operational stand-by time was included in form of a weather allowance. Weather allowances depend on many factors such as vessel capabilities, and deployment and recovery processes. Comparable numbers from the North Sea offshore oil & gas industry were adapted to local conditions, based on feedback from local offshore operators.

Based on wave data and feedback from local offshore operators, the best weather at the proposed site can be found in the months of July, August and September. Installation activities should be carried out during that time-frame.

Figure 14: Towing the Pelamis P-750

Operational Activities

Pelamis was designed with a minimum amount of physical intervention in mind. Sophisticated remote monitoring capabilities allow the operator to monitor the device and, in case of a failure, isolate the fault to determine the exact problem and if required schedule physical intervention. In addition, the device features many levels of redundancies which will reduce the need to immediately respond to a failure.

The devices maintenance strategy is to completely detach the device from its moorings, tow the unit into a nearby harbor and carry out any repair activities along a dock-side. Initially it is envisioned, that the device is removed every year for maintenance activities. As the technology becomes more mature, these regular maintenance activities will become more infrequent. For the commercial reference plant, we assumed that removal for scheduled maintenance occurs every 2 years.

Every 10 years, the device will be recovered for a complete overhaul and refit. For that purpose, it will need to be de-ballasted and completely recovered to land. It is likely that only some touch-up painting will be required and the exchange of some of the power take off elements, such as hydraulic rams will take place at that point. The device will also need to be inspected at that time by the American Bureau of Shipping (ABS) or a related agency.

5. System Design – Pilot Plant

The outline below (Figure 15) shows the electrical setup of the demonstration pilot plant. A single Pelamis WEC device is floating on the surface and moored in a water depth of 50m – 60m. An umbilical riser cable is connecting the Pelamis to a junction box on the ocean floor. From this junction box, a double armored 3 phase cable is buried into soft sediments to the outfall of the effluent pipe. This outfall is located about 1km from shore and leads to the International paper facility. An additional cable section is then used to connect the power from the effluent pipe outfall to the grid interconnection point. The Gardiner substation is located next to the property of the International Papers facility in Gardiner.

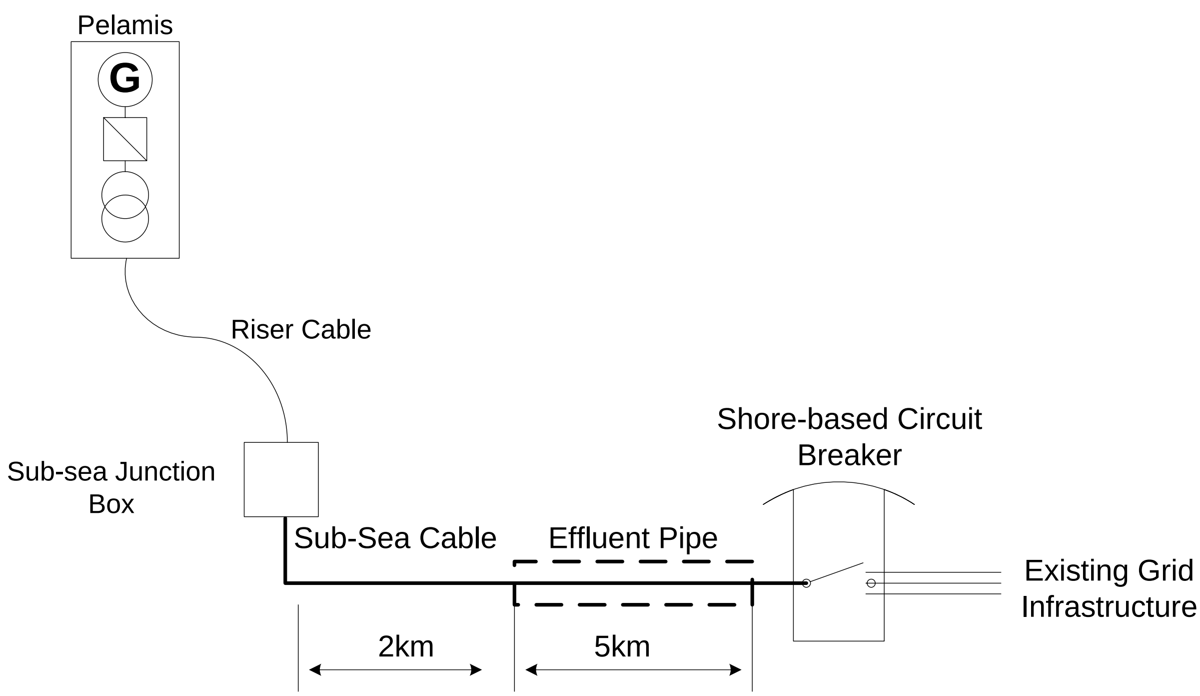

Figure 15: Electrical Interconnection of a 1 Pelamis Pilot Plant

6. System Design - Commercial Scale Wave Power Plant

While the conceptual design of the pilot plant system focused on finding existing easements, allowing the installation of a small demonstration system in a cost effective manner, the commercial scale wave farm design focused on establishing a solid costing base case, and assessing manufacturing and true operational costs for a large plant. The commercial scale cost numbers were used to compare energy costs to commercial wind farms to come to a conclusion on the cost competitiveness of wave power.

The existing effluent line outfall at the proposed site will enable a low cost introduction and a gradual build-out of capacity, leveraging existing infrastructure and easements in Gardiner. It is envisioned, that such a site could gradually emerge from a pilot site into a commercial farm, allowing local industry to gain experience in the operational aspects of managing such wave farms and build local expertise in driving down the cost of manufacturing and operating these devices. The following subsections outline the electrical system setup, the physical layout and the operational and maintenance requirements of such a deployment.

Electrical Interconnection and Physical Layout

As shown in figure 16, the commercial system uses a total of 4 clusters, each one containing 45 Pelamis units (180 Pelamis WEC devices), connected to sub-sea cables. Each cluster consists of 3 rows with 15 devices in per row. The 4 sub-sea cables are connecting the 4 clusters to shore as shown in Figure 16. The electrical interconnection of the devices is accomplished with flexible jumper cables, connecting the units in mid-water. The introduction of 4 independent sub-sea cables and the interconnection on the surface will provide some redundancy in the wave farm arrangement.

The 4 clusters are each 2.25 km long and 1.8 km wide, covering an ocean stretch of roughly 9 km. The 4 arrays and their safety area occupy roughly 16 square kilometers. Further device stacking of up to 4 rows might be possible reducing the array length, but is not considered in this design, as subsequent rows of devices will likely see a diminished wave energy resource and therefore yield a lower output. Such effects and their impacts on performance are not well understood at present.

Based on the above setup the following key site parameters emerged:

Array Length	9 km
Array Width	1.8 km
Device Spacing	150m
Number of Rows	3
Total Sub-sea Cable length	14 km
System Voltage	26kV
Sub-sea cable specs	26kV / 40MVA / 3-phase with fiber optic core

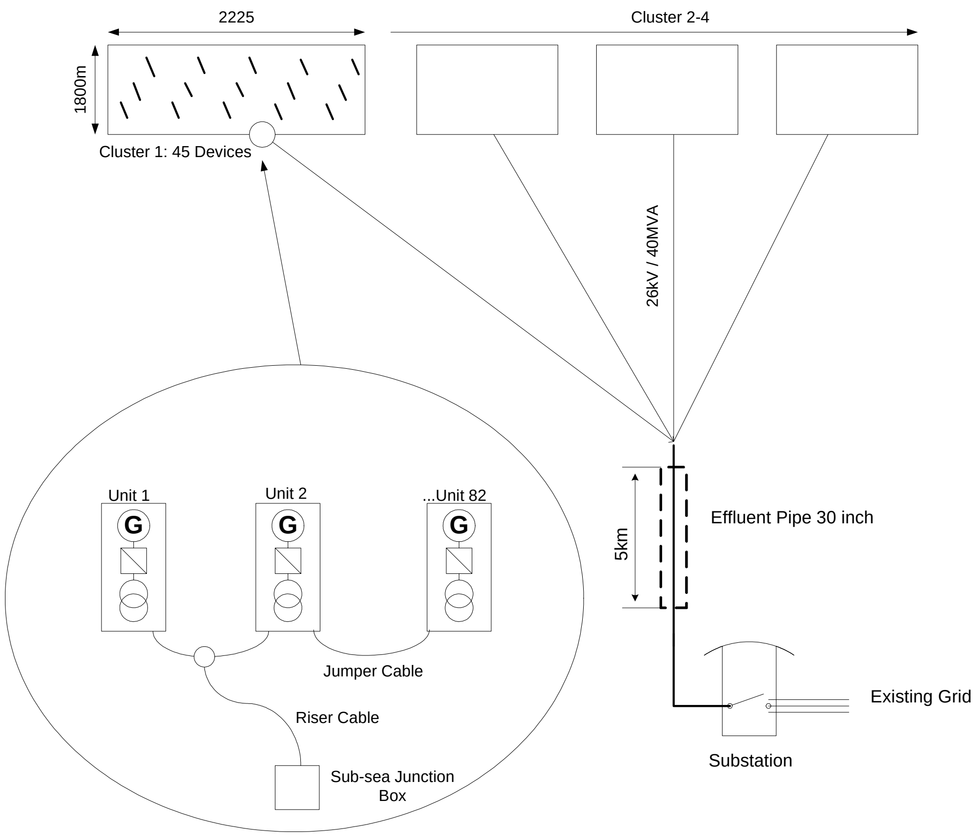

Figure 16: Overall System Layout and Electrical Connections

Operational and Maintenance Requirements

General operational activities are outlined in a previous section. It made economic sense for this wave farm to include an AHATS class vessel in the capital cost of the project. Based on the workload, the vessel will be at 100% capacity during the installation phase of the project and then it's usage will drop to less then 50% to operate the wave farm.

This type of vessel has sufficient deck space to accommodate the heavy mooring pieces and a large enough crane to handle the moorings. In addition the vessel has dynamic positioning capabilities and is equipped for a 24-hour operation. Based on the work loads involved with O&M and 10-year refit operation a total full-time crew of 18 is required. This includes onshore personnel to carry out annual maintenance activities and 10-year refits.

O&M activities can be carried out at a suitable pier side in Reedsport, with the device remaining in the water. For the 10-year refit, the device will need to be recovered to land onto a rail-type system on which these activities can be carried out. While some of these facilities are available at a local shipyard in Reedsport, budget allowance was given to accommodate improvement to make such operations simpler.

7. Device Performance

The device performance was assessed based on data supplied by the manufacturer and the wave climate (outlined in previous section). The following summarizes the projected device performance as described in Section 2 off the coast of Douglas County Oregon.

Transmission line losses for the 7km sub-sea cable from the offshore farm to the grid interconnection point at Gardiner substation were ignored as they are likely not significant at the design voltage levels used and can only be estimated in a detailed design phase.

Scatter or joint probability diagrams for the wave energy resource were created for each month and used for power production calculations. Figure 17 shows the average power (kW) delivered to the grid by a single Pelamis WEC Device sited as described in Section 2 off the coast Douglas County, Oregon.

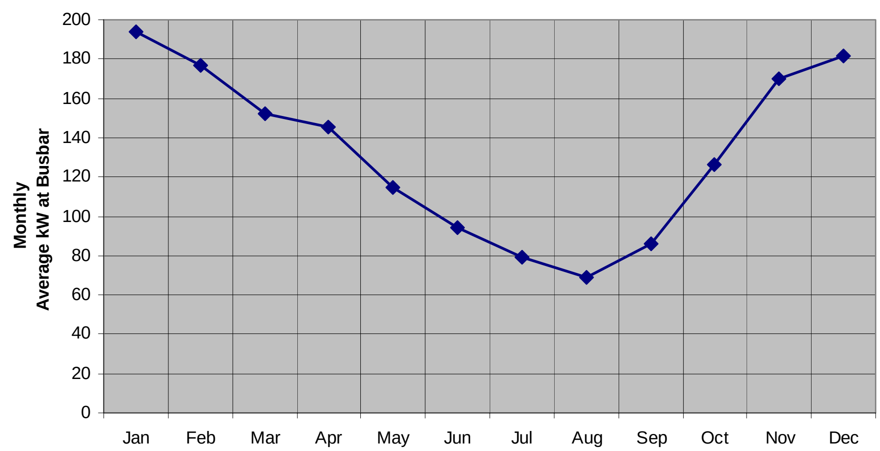

Figure 17: Monthly average power delivered to bus bar – Pilot Plant

A scatter diagram of the annual and monthly wave energy available at the Gardiner site was developed using long-term statistics from the Coquille River CDIP 037 wave measurement buoy. The scatter diagram for the annual energy is shown in Table 2.

Table 2: Oregon Site Annual occurrence of hours per sea-state

CDIP 0037		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	8766
Coquille River		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	*Total*
Hs and Tp bin boundaries											Tp (sec)									*annual*
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	*hours*
9.75	10.25	**10**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
9.25	9.75	**9.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.75	9.25	**9**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
8.25	8.75	**8.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
7.75	8.25	**8**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
7.25	7.75	**7.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
6.75	7.25	**7**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*1*
6.25	6.75	**6.5**	0	0	0	0	0	0	0	0	0	1	1	2	1	0	0	0	0	*5*
5.75	6.25	**6**	0	0	0	0	0	0	0	0	1	2	3	2	1	3	1	0	0	*13*
5.25	5.75	**5.5**	0	0	0	0	0	0	0	0	0	3	6	5	1	0	1	0	0	*18*
4.75	5.25	**5**	0	0	0	0	0	0	1	2	4	8	18	10	5	4	1	0	0	*53*
4.25	4.75	**4.5**	0	0	0	0	0	0	3	5	10	25	32	16	4	5	0	1	0	*101*
3.75	4.25	**4**	0	0	0	0	1	1	9	14	21	41	64	25	12	8	5	5	1	*207*
3.25	3.75	**3.5**	0	0	0	1	1	7	17	21	49	69	98	31	19	12	9	5	0	*339*
2.75	3.25	**3**	0	0	0	2	8	16	51	69	110	152	128	52	22	15	6	5	1	*638*
2.25	2.75	**2.5**	0	0	0	13	25	57	153	142	174	207	158	51	35	25	12	5	2	*1,057*
1.75	2.25	**2**	0	0	5	44	108	184	329	256	274	254	181	57	36	31	23	11	4	*1,796*
1.25	1.75	**1.5**	0	1	24	143	290	379	471	357	220	197	144	55	37	27	17	9	2	*2,372*
0.75	1.25	**1**	0	9	55	146	304	335	317	312	115	87	81	45	31	29	12	6	0	*1,884*
0.25	0.75	**0.5**	0	1	7	21	35	34	25	65	16	11	21	16	12	7	3	0	0	*274*
0	0.25	**0.125**	0	0	0	0	0	1	5	0	0	0	0	0	0	0	0	0	0	*7*
		8,766	*1*	*10*	*91*	*369*	*772*	*1,014*	*1,383*	*1,241*	*996*	*1,057*	*934*	*367*	*216*	*166*	*92*	*48*	*9*	***8,766***

Table 3: Pelamis Wave Energy Conversion Absorption Performance (kW)

									Tp (s)								
Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20
10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	739	0	0	0	0
7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	750	0	566	0	495	0	0
6.5	0	0	0	0	0	0	0	0	0	750	723	592	617	513	0	0	0
6	0	0	0	0	0	0	741	0	750	750	616	633	525	476	396	398	0
5.5	0	0	0	0	0	0	750	0	750	635	642	532	482	400	399	0	0
5	0	0	0	0	0	0	750	750	644	641	531	482	399	394	330	308	0
4.5	0	0	0	0	0	0	738	634	626	520	473	390	382	319	299	250	0
4	0	0	0	0	632	616	583	585	494	454	374	361	339	283	236	197	150
3.5	0	0	0	326	484	577	568	502	421	394	330	312	260	216	196	164	0
3	0	0	0	246	402	424	417	369	343	331	275	229	208	173	144	120	84
2.5	0	0	55	171	279	342	351	320	274	230	210	174	145	120	100	84	59
2	0	0	35	109	199	219	225	205	195	162	135	112	93	77	64	54	38
1.5	0	0	0	62	112	141	143	129	110	91	76	63	52	43	36	30	21
1	0	0	0	27	50	62	64	57	49	41	34	28	23	0	0	0	0
0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

By multiplying each cell of the Pelamis performance scatter diagram (Table 3) with each corresponding cell in the hours of reoccurrence scatter diagram (Table 2) the total energy in each sea state was calculated. By summing up the two tables, the annual output (MWh/year) for the single Pelamis WEC device pilot plant shown in Table 4 was derived

Table 4: Pilot Plant Pelamis Performance

Device Rated Capacity	750kW
Annual Energy Absorbed	1,472 MWh/year
Device Availability	85%
Power Conversion Efficiency	80%
Annual Generation at bus bar	1,001 MWh/year
Average Power Output at bus bar	114 kW

The commercial plant performance was assessed using the pilot plants performance data as its basis. In addition certain performance improvements were considered. Based on well established wave theory, the Pelamis device is only absorbing a small portion of its theoretical limit. An increase in performance by a factor of 2-3 is possible without significant changes to the device geometry. For the purpose of this study, only performance improvements were considered which could be achieved in the near future, without any additional research. Additional performance improvements included in the commercial plant performance assessment are:

- Changing the mooring configuration will yield a performance improvement of 37%. This mooring configuration has been evaluated in wave tank tests and theoretical studies by Ocean Power Delivery and is well quantified.

- The current Power Conversion Modules use standard off the shelf components. Customizing some of these components could increase the power conversion efficiency by more then 10%. The technologies to improve the conversion efficiency exist and are therefore included in the performance for the commercial plant.

- The rated capacity was changed to 500kW, because the 750kW design is overrated for the Oregon wave climate. The 500kW power conversion module is also reflected in the cost assessment of the power plant and has little impact (<5%) on the annual output of the Pelamis in Oregon.

Table 5 summarizes the performance values for a commercial Pelamis module incorporating improvements as outlined above.

Table 5: Commercial Plant Pelamis Performance

Device Rated Capacity	500kW
Annual Energy Absorbed	1,997 MWh/year
Device Availability	95%
Power Conversion Efficiency	88%
Annual Generation at bus bar	1,669 MWh/year
Average Electrical Power at bus bar	191 kW

8. Cost Assessment – Pilot Plant

The cost assessment for the pilot was carried out using a rigorous assessment of each cost center. Installation activities were outlined in detail and hourly breakdowns of offshore operational activity created to properly understand the processes and associated cost implications. Wherever possible, manufacturing estimates were obtained from local manufacturers. An uncertainty range was associated to each costing element and a Monte Carlo Simulation was run to determine the uncertainty of capital cost. Operational cost was not assessed in detail for the Pilot plant. This is a task that is scheduled for subsequent project phases. Cost centers were validated by OPD, based on their production experience of their first full scale prototype machine, which was deployed in 2004. Based on the above assumptions the following results in constant year 2004$ are presented:

Table 6: Cost Summary Table rounded to the nearest $1000

Cost Element	Pilot Plant	Basis
Onshore Transmission & Grid Interconnection	$580,000	(1)
Subsea Cables	$300,000	(2)
Pelamis Power Conversion Modules	$1,535,000	(3)
Pelamis Manufactured Steel Sections	$850,000	(4)
Pelamis Mooring	$243,000	(5)
Installation	$699,000	(6)
Construction Mgmt and Commissioning (10% of cost)	$420,000	(7)
Total Before Fed Inv and State Renewable Tax Credit	**$4,627,000**	
Renewable Inv Tax Credit (25% up to a limit of $10 M)	$1,102,000	(8)
Federal Investment Tax Credit (10% of Total)	$463,000	
Total After Fed Inv and State Renewable Tax Credit	**$3,062,000**	

1) Cost includes a breaker circuit and double armored power cable being laid through existing easement in place. Cable cost is based on quotes from Olex cables.

2) Subsea cable cost is based on quotes from Olex cables. It includes a sub-sea, pressure compensated junction box, to connect the riser cable.

3) Based on estimate by Ocean Power Delivery. Shipping cost is included from Edinburgh (UK) to Reedsport Oregon based on quote by Menlo International.

4) Cost for 4 manufactured steel sections was estimated by using $2,850/per ton of manufactured steel. Each steel section of this unit weighs roughly 70 tons (excluding ballast). This is consistent with OPD experience with manufacturing their pre-production machine and input from local manufacturers. It includes cast elements and protective coatings. Range of cost from different sources was $2,500/ton - $3,500/ton.

5) Based on OPD's experience with their pre-production prototype. Cross checks were performed using local construction management feedback.

6) Installation cost was estimated by a rigorous assessment of vessel handling requirements, breakdown of installation tasks, quotes from local operators for vessel cost, fuel and crew, and allowance for weather downtime.

7) Based on E2I EPRI Project Team experience managing like custom construction projects and commissioning to owner acceptance.

8) Oregon has a business energy tax credit of 25% of project cost, up to a $10 million credit in the first year. These tax credits may be sold and transferred to commercial entities who are in tax situations where they may be used. Ty[ical selling price is at about 90% of the value.

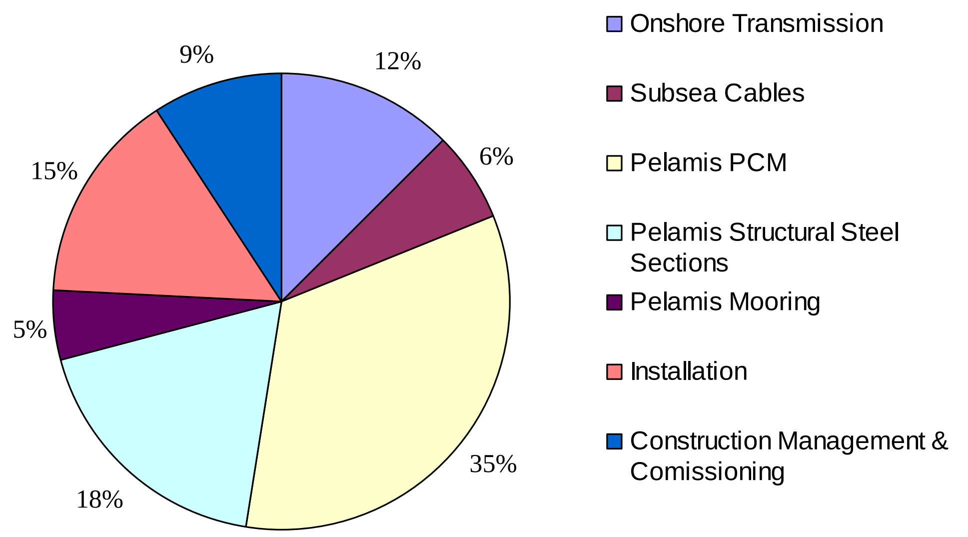

Figure 18: Pie Chart of cost centers for single unit installation

Cost uncertainties were estimated for each cost component and a Monte Carlo simulation was used to determine the likely capital uncertainty of the project. Figure 19 below shows the cost as a function of cost certainty as an S-curve. A steep slope indicates a small amount of uncertainty, while a flat slope indicates a large amount of uncertainty. It shows that the cost accuracy is within -20% to +23%. This bottoms-up approach to uncertainty estimation compares to an initially estimated accuracy of -25% to +30% for a pilot scale plant based on a preliminary cost estimate rating (from the top-down EPRI model described in Ref 3).

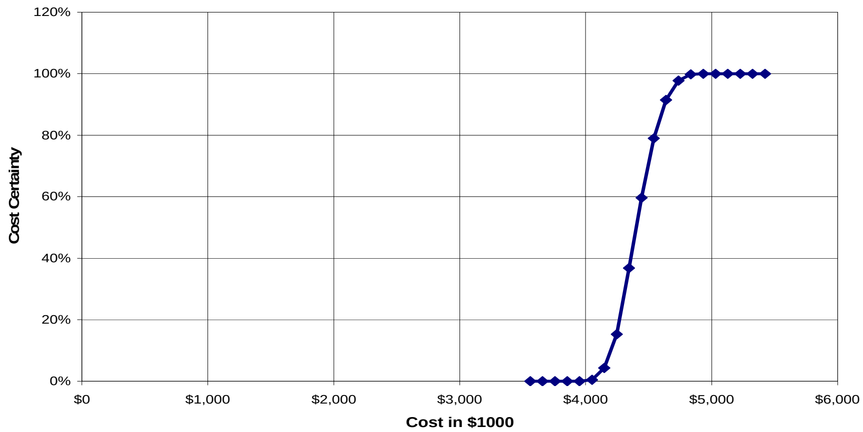

Figure 19: Installed Cost Uncertainty based on Monte Carlo Simulation

9. Cost Assessment – Commercial Scale Plant

The cost assessment for the commercial wave power plant followed a rigorous assessment of each cost center. Instead of simply applying learning curves, a point design for the commercial plant using 180 devices was outlined and its cost estimated. For cost centers, which lend themselves well to cost reduction, outlines were created of how such cost reduction will be achieved. Installation activities were outline in detail and hourly breakdowns of offshore operational activity created to properly understand their impacts on cost and resources. Cost centers were validated by Ocean Power Delivery, based on their production experience of their first full scale prototype machine, which was deployed in 2004. Operational tasks and outlines were validated by local operators.

Table 7: Installed Cost Breakdown for Commercial Scale Plant

Cost Element	**328-Pelamis Device System**		**Basis**
Constant Dollar Year	2004	in %	
Installed Cost			
Onshore Transmission & Grid Interconnection	$2,500,000	1.2.%	
Subsea Cables	$1,850,000	0.7%	
180 x Mooring Spread @ $117,247 each	$21,104,460	9.9%	(1)
180 x Power Conversion Modules @ $623,960 each	$112,312,800	52.2%	(2)
180 x Concrete Structural Sections @ $244,800 each	$44,064,000	20.6%	(3)
Facilities	$12,000,000	5.5%	(4)
Installation	$11,301,000	5.4%	(5)
Construction Mgmt and Commissioning (5% of cost)	$9,691,000	4.5%	(6)
Total Plant Cost	**$214,823,260**	**100%**	
Construction Financing Cost	$20,409.682		
Total Installed Cost	**$235,232,942**		
Yearly O&M			
Labor	$2,322,425	19.6%	(7)
Parts (2%)	$4,295,752	40.2%	(8)
Insurance (2%)	$4,295,752	40.2%	(9)
Total	**$10,913,929**	**100%**	
10-year Refit			
Operation	$9,758,321	38.2%	(7)
Parts	$13,756,280	61.8%	(7)
Total	**$23,534,601**	**100%**	

(1) The mooring spread is an assembly of standard elements and equipment. A moderate cost reduction of 30% was assumed (as compared to the prototype). This cost reduction can easily be achieved by purchasing in larger quantities.

(2) Three (3) Power Conversion Modules (PCM) are required for a single Pelamis unit. Cost of a hydro-electric power take off will be significantly lower then initial production units. The performance assessment for our reference site also shows that the PCMs are overrated and reducing the rated power to 300kW per device would yield a relatively small decrease in annual output. This is mainly attributed to the fact that the Oregon site has lower energy levels then UK sites for which the device was originally developed. Reference 6 shows that the cost for the three (3) PCM 500kW prototype unit in production volume is $289,00 for the power conversion train alone and another $234,000 for the manufactured steel enclosure, hinges and assembly in production volume for a total Pelamis unit cost (3 PCMs) of $523,000.

(3) The summary table in Reference 5 shows a production cost of $51,000 per tube or $204,000 per device excluding the end caps on the tubes. Including the end caps, the cost for the 4 concrete sections is $245,000 per Pelamis device. Concrete is widely used in the offshore industry and is considered the most reliable option among construction materials. However, it is important to understand that a design using concrete tubes will require design efforts up-front, to properly test the long-term fatigue characteristics of a particular design.

(4) Includes an AHATS class vessel, which is equipped to operate 24 hours per day and some provisions for dock modifications and heavy lift equipment, such as a crane.

(5) Installation cost was estimated by a rigorous assessment of vessel handling requirements, breakdown of installation tasks, quotes from local operators for vessel cost, fuel and crew and allowance for weather downtime.

(6) Construction management and commissioning cost was estimated at 5% of the plant cost based on discussions with experienced construction management organizations

(7) The most cost effective approach to operate the wave power plant included an AHATS class vessel capable to operate effectively 24-hours per day. Based on a rigorous assessment of the tasks involved in operating the wave farm, it was concluded, that the vessel would be at less then 50% capacity. An operational crew of 6 persons is required to operate the vessel and carry out tasks at sea. Shore-based and offshore operations and maintenance tasks were estimated and the results showed that a crew of 18 persons is required to operate a 180 Pelamis wave farm. In other words, it will require 0.1 full-time crew per device for the operation of a commercial wave power plant. Reduction in personnel is possible with appropriate redesign of the units to make them easier to handle and improve their reliability. A major refit is required every 10-years for a commercial plant. In other words, assuming a 20-year life, one refit is required. Elements such as hydraulic rams are replaced during that period. In addition, some of the hull is repainted. Unlike the bi-annual maintenance activities, which can be carried out on a pier side, the 10-year refit requires de-ballasting the device and recovering it onto land, ideally onto a rail-

type system. It will also need to be inspected at that point by ABS or a related agency.

(8) It is unclear at present what the failure rate of components and sub-systems are. Operational experience will be required with this specific technology to draw any conclusions. An allowance of 2% of Capital cost was included for a commercial project.

(9) 2% is a typical insurance rate for offshore projects using mature technology. Rates might be slightly higher during construction and then drop off during operation.

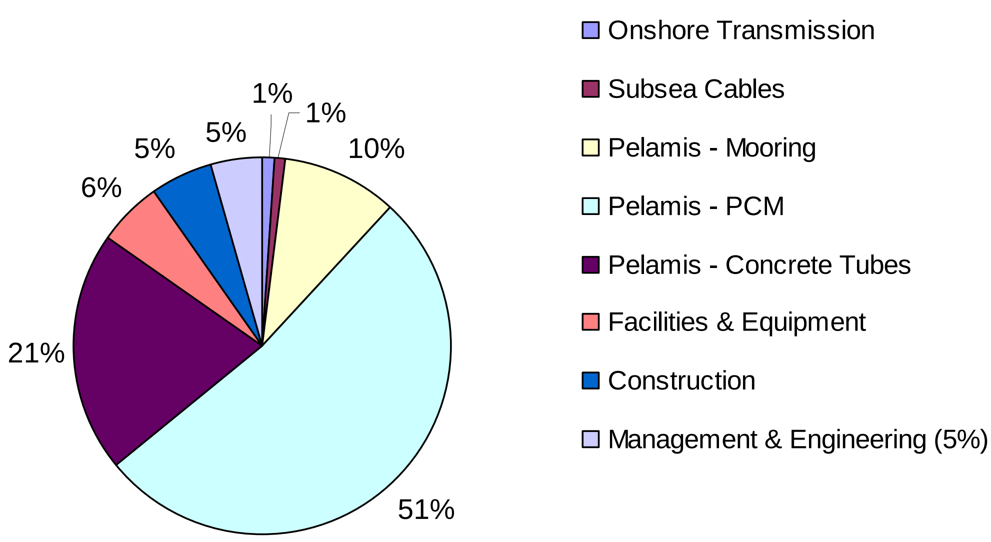

Figure 20: Installed Cost Breakdown for commercial scale plant

Cost uncertainties were estimated for each cost component and a Monte Carlo simulation, using triangular approximation was run to determine the likely capital uncertainty of the project. Figure 21 below shows the cost as a function of cost certainty as an S-curve. A steep slope indicates little uncertainty, while a flat slope indicates a large amount of uncertainty. The uncertainty for a large-scale project is bigger at this stage because it is unclear at present how well cost reductions could be achieved.

It shows that the cost accuracy is -24% to + 35%. This bottoms-up approach to uncertainty estimation compares to an initially estimated accuracy of -25% to +30% (from the top-down EPRI model described in Reference 2). The reason, why the projections to a commercial plant have a higher uncertainty, then for a single unit demonstration plant is because certain cost centers include cost reduction measures, which have a higher uncertainty.

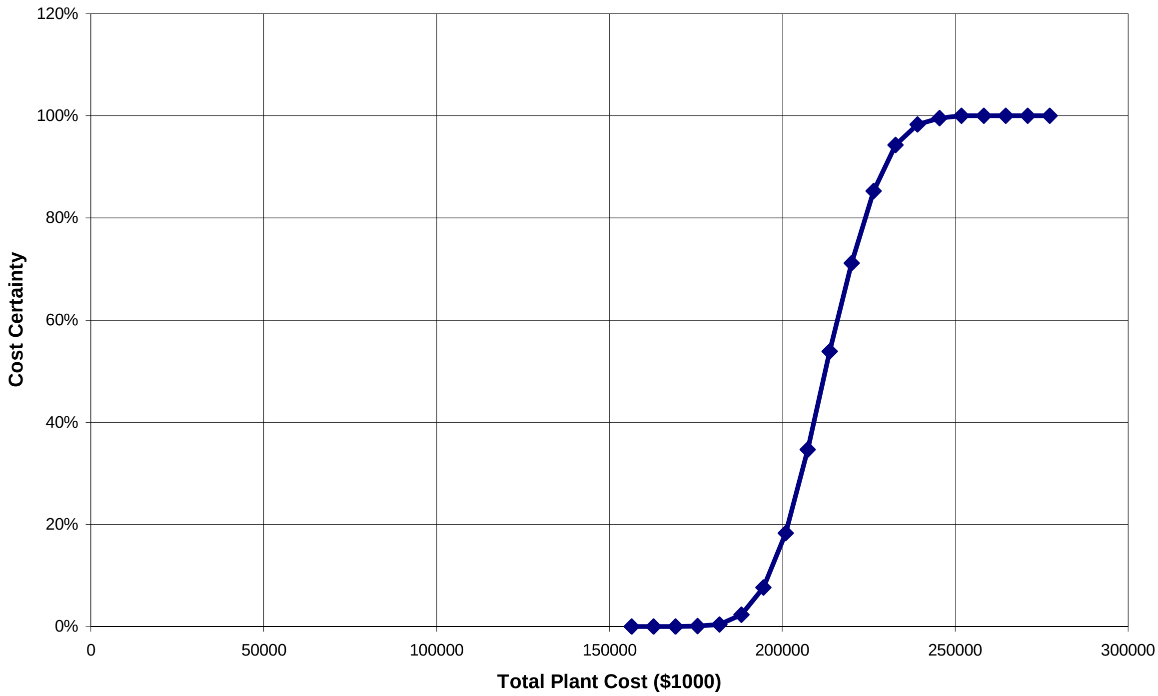

Figure 21: Installed Cost uncertainty S-curve

10. Cost of Electricity/Internal Rate of Return Assessment – Commercial Scale Plant

The Utility Generators (UG) cost of electricity (COE) and the Non-Utility Generator (NUG) internal rate of return(IRR) was assessed based on previously developed methodologies described in reference 3. In order to calculate the COE and IRR, underlying assumptions such as applicable tax rates, tax incentives, depreciation schedules and electricity price forecasts were identified based on the states applicable regulatory environment and are presented in Table 8. Spreadsheet solutions were created for both Utility and Non-Utility Generators and results are outlined in this section.

Table 8: Key Assumptions for the State of Oregon

	UG	NUG
Year Constant Dollar	2004	2004
Number of Devices	180	180
Annual Electrical Plant Output	300,000 MWh/yr	300,000 MWh/yr
Book Life	20 years	20 years
Taxation		
Federal Tax Rate	35%	35%
State Tax Rate (Oregon)	6.6%	6.6%
Composite Tax Rate	39.3%	39.3%
Financing		
Common Equity Financing Share	52%	30%
Preferred Equity Financing Share	13%	
Debt Financing Share	35%	70%
Nominal Common Equity Financing Rate	13%	17%
Nominal Preferred Equity Financing Rate	10.5%	
Nominal Debt Financing Rate	7.5%	8%
Real Common Equity Financing Rate	9.7	13.6
Real Preferred Equity Financing Rate	7.3	
Real Debt Financing Rate	4.4	4.9
Inflation rate	3%	3%
Renewable Credits & Incentives		
Federal Investment Tax Credit	10% of TPI	10% of TPI
Federal Production Tax Credit	1.8 cents/kWh (first 10 years)	1.8 cents/kWh (first 10 years)
State Investment Tax Credit	25% of cost ($2.5M	25% of cost ($2.5M credit

	credit limit in first year)	limit in first year)
State Production Tax Credit	N/A	N/A
Depreciation	MACR Accelerated 5 years	MACR Accelerated 5 years
Industrial Electricity Price (2002$) - The closest we could get to the electricity price as sold by a merchant plant to the grid operator	N/A	4.7 cents/kWh
Industrial Electricity Price Forecast (2002$)	N/A	8% decline from 2002 to 2008, stable through 2011 and then a constant escalation rate of 0.3%

The capital, O&M and 10-Year Refit cost and their uncertainty was previously estimated in section 8. Table 9 shows the translation of those numbers into a levelized cost of electricity (COE), both using nominal and real financing rates, and the methodology described in Reference 3. Appendix B contains the workbook spreadsheets used in calculating the best estimate wave energy case shown below in Table 9.

Table 9 Major Cost elements and their Impacts on Cost of Electricity for Utility Generators (2004 constant year $)

Cost Element	Low Estimate	Best Estimate	High Estimate
Total Plant Investment	$174,338,000	$235,233,000	$308,987,000
Annual O&M Cost	$8,731,143	$10,913,929	$16,370,884
10-year Refit Cost (1 time cost)	$15,569,884	$23,534,601	$31476,927
Nominal Fixed Charge Rate	9.2%	9.7%	10.1%
Nominal Cost of Electricity (c/kWh)	8.6	11.6	16.7
Real Fixed Charge rate	6.8%	7.2%	7.5%
Cost of Electricity (c/kWh)	7.2	9.7	14.0

O&M costs have a significant effect on COE. It is a cost center with potential for significant improvements and is also the cost center with the most uncertainty at present. As there is little experience with operating such wave farms, there is little actual experience against which these estimates could be validated. Currently standard offshore oil & gas industry practices and rates were applied to derive appropriate operational costs. The offshore oil & gas industry is well known for its high operational overhead and steep cost profiles. In order to reduce this cost center, the industry needs to learn by doing, by operating small wave farms. Cost reductions can be expected by improving the reliability of the deployed devices as well as improving the operational strategies.

Table 10 shows the translation of capital, O&M and 10-Year Refit cost and their uncertainty into an internal rate of return (IRR) using the methodology described in Reference 3.

In terms of definition, the Internal Rate of Return (IRR) is the discount rate that sets the present value of the net cash flows over the life of the plant to the equity investment at the commercial operating date. The net present value represents the present value of profit or returns using the time value of money. This calculation results from discounting the net cash flows at the 'discount rate.' The economics analysis for this first commercial offshore wave power plant is described in detail in Appendix C.

Table 10: Major Cost elements and their impacts on Cost of Electricity for Non Utility Generators (2008 initial operation – 20 year life – current year $)

Cost Element	Lowest Estimate	Best Estimate	High Estimate
Total Plant Investment (2004)	$174,337,945	$236,601,000	$308,987,007
Annual O&M Cost (2004$)	$8,731,143	$10,913,929	$16,370,884
10-year Refit Cost (2004$)	$15,569,884	$23,534,601	$31476,927
Internal Rate of Return	No IRR	No IRR	NO IRR

Table 10 shows that the first commercial plant owned by a NUG does not have a positive internal rate of return. This is not surprising given the 11.6 cents/kWh nominal (9.7 cents/kWh real) COE and the industrial electricity selling price in this case for Oregon of 4.7 cents/kWh (2002$). Figure 22 and 23 shows the best cost estimate net and cumulative cash in current year dollars for the 20 year life of the project

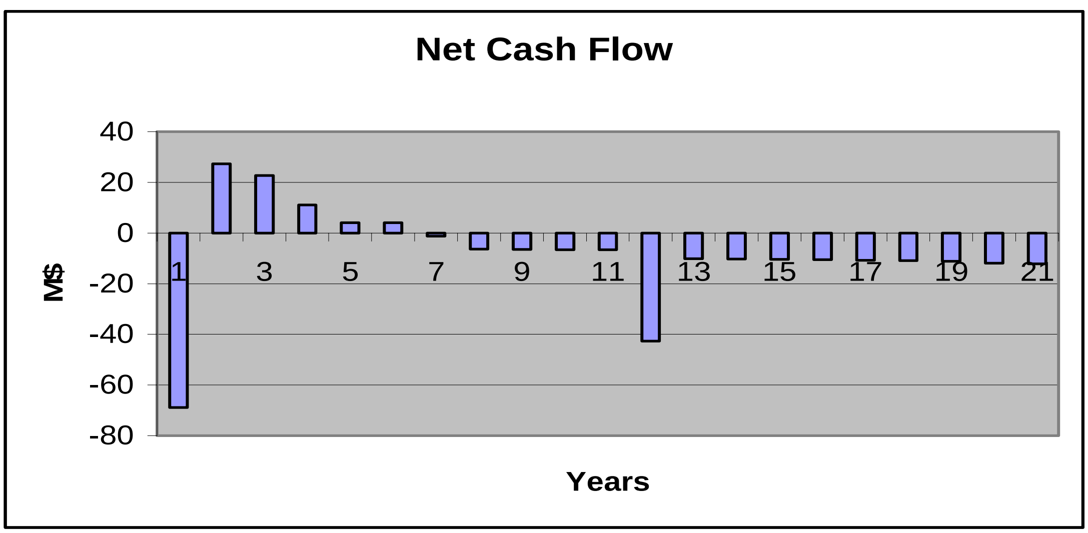

Figure 22: Net and Cumulative Cash Flow Over 20 Year Project Life

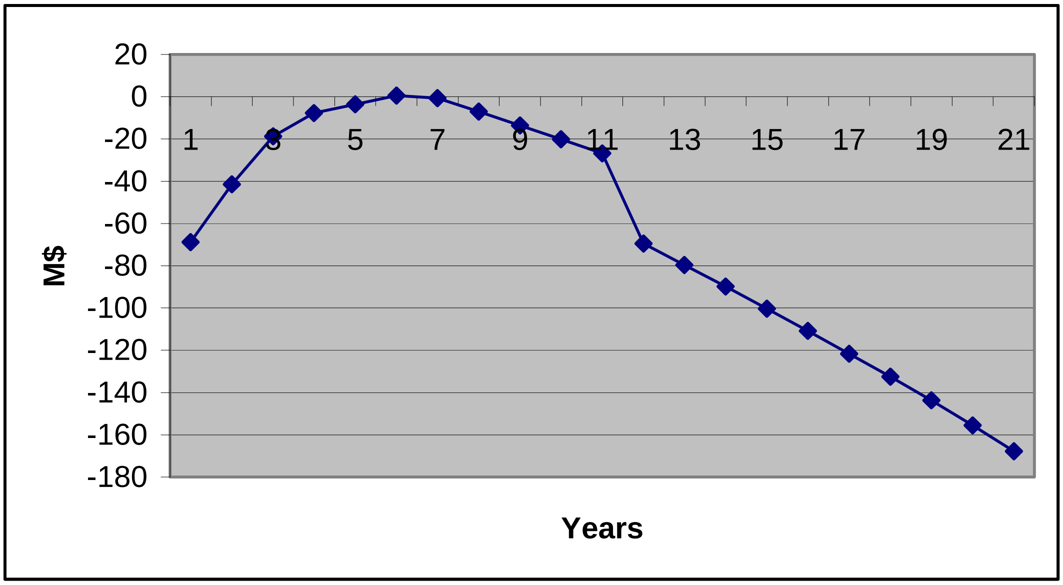

Figure 23: Cumulative Cash Flow Over 20 Year Project Life

The next sections describe learning curves, and the reduction in cost associated with the learning experience and the comparison of wind and wave energy technology at various levels of learning (i.e., cumulative production volumes)

11. Learning Curves

Operating in competitive markets makes enterprises do better. This fact is at the core of the learning curve phenomenon. Learning through production experience reduces prices for energy technologies and these reductions influence the dynamic competition among technologies. In addition, learning curves are used by Government policymakers to design measures to stimulate the production of new technologies to where they become commercially competitive.

In order to make available environmentally effective technologies (or technologies that have characteristics that are deemed to be of societal benefit), which are price competitive, governments support these technologies through funding of RD&D and through price subsidies or other forms of deployment policy. Crucial questions concern how much support a technology needs to become competitive and how much of this support has to come from government budgets. Learning curves make it possible to answer such questions because they provide a simple, quantitative relationship between price and the cumulative production or use of a technology. There is overwhelming empirical support for such a price-experience relationship forms all fields of industrial activity, including the production of equipment that transfers or uses energy.

As explained in reference 3, cost reduction goes hand-in-hand with cumulative production experience and follows logarithmic relations such that for each doubling of the cumulative production volume, there is a corresponding percentage drop in cost. An 82% learning curve is the curve to use for wave technology based on experience in the wind, photovoltaic and offshore oil and gas platform industry.

How a learning curve is used to show the deployment investment necessary to make a technology, such as wave energy, competitive with an existing technology, such as wind energy is illustrated in Figure 23. It does not, however, forecast when the technologies will break-even. The time of break-even depends on the deployment rates, which the decision-maker can influence through policy.

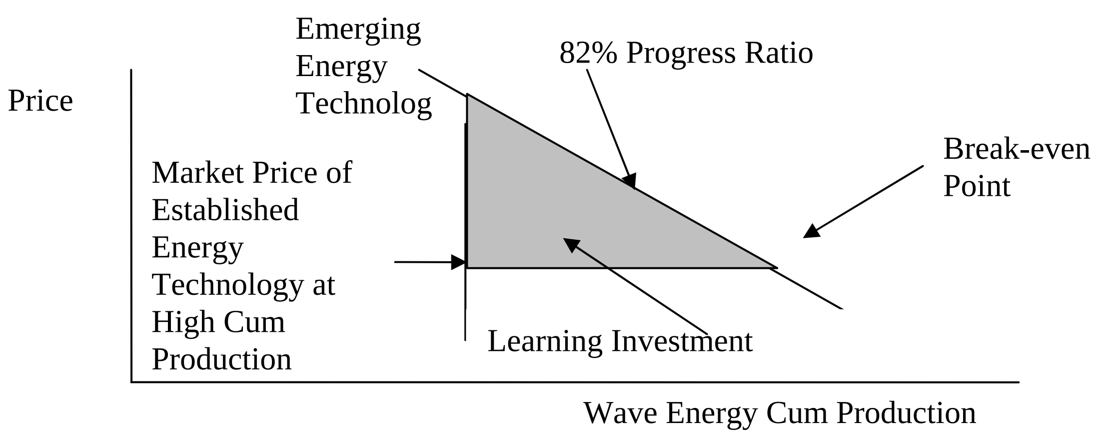

Figure 24: Learning Investment Required

12. Comparison with Commercial Scale Wind Farm

The costs (in 2004$) of a pilot offshore wave energy power are described in Section 7 using the production experience gained by OPD from the build of the first prototype machine. The costs (in 2004$) of a commercial scale offshore wave energy power plant are described in Section 8 and are an extension of the costs of the pilot plant with cost reductions estimated for each major component, i.e., on an individual basis and not using an overall learning curve effect.

In this section, we apply learning cost reductions discussed in the previous section to wave power systems using the cost of the 90 MW commercial wave plant as the entry point to the learning curve process. The purpose is to enable the comparison of the cost of an offshore commercial scale wave farm versus the cost of an equivalent wind farm assuming the same level of production experience for both technologies.

For wind power plants and as reported by the National Wind Coordinating Council (NWCC), the installed capital cost has decreased from more than $2,500/kW in the early eighties to the 1997 range of $900/kW to $1,200/kW in 1997$.[4] The actual cost for a given installation depends on the size of the installation, the difficulty of construction, and the sophistication of the equipment and supporting infrastructure. "Total installed cumulative production volume topped 39,000 MW in 2003 and was about 10,000 MW in 1997."[5] Based on the above numbers, the wind industry shows a progress ratio of 82%.

It turns out that the comparison of installed cost per unit of maximum or rated power as a function of cumulative installed capacity is not a meaningful comparison because of the effect of overrated or derated energy conversion devices. For example, a turbine generator set rated at 10 times the 500 kW rating of the commercial Oregon Pelamis could be installed at only a small increase in system cost. On a $/kW basis, however, the number would plunge without any significant increase in annual produced energy. The 180 device Pelamis 1st commercial plant system has a rating of 90 MW, however, it could be overrated or derated by the manufacturer without much of a change in the annual energy production. Therefore, the wave energy learning curve can be moved up or down in this chart at will and therefore has no useful meaning for the economic competitiveness to other renewable technologies..

[4] "Wind Energy Costs" NWCC Wind Energy Series, Jan 1997, No 11

[5] "Wind Energy Industry Grows at Steady Pace, Adds Over 8,000 MW in 2003" American Wind Energy Association

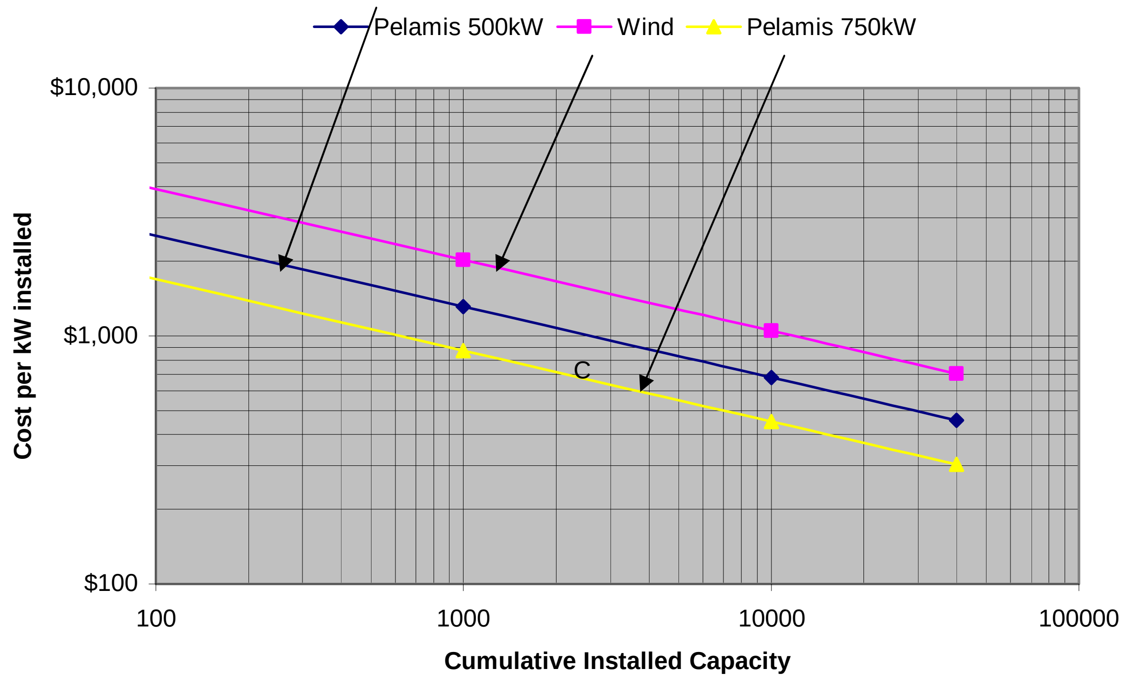

Figure 25: Installed Cost per kW installed as a Function of Installed Capacity

In order to make a meaningful comparison between wind and wave, a levelized comparison using COE numbers is required. An 82% learning curve was used to extend the wave energy total plant investment cost from the estimated 90 MW cumulative production volume value to 40,000 MW. The following wave energy O&M assumptions were used:

- Offshore systems are more difficult to access then onshore systems and it is likely that it will always be more expensive to operate them then onshore systems
- Reliability will be similar to modern wind turbines today (at equivalent cumulative production volumes)
- Improvement in O&M costs can be made by paying greater attention to operational aspects in the design of the device.

Based on numerous discussions, we believe that a reasonable assumption for mature wave power technology O&M cost is 50% higher then shore based wind at a cumulative installed capacity of 40,000 MW. Using the O&M cost quoted by WCC of 1.29 cents/kWh, wave would have 1.9 cents/kWh at the equivalent cumulative installed capacity. Based on this assumption, COE costing curves are presented in Figure 26 as a function of installed capacity and compared to wind. Optimistic and pessimistic scenarios are presented based on the uncertainty in opening Total Plant Investment and O&M costs of the commercial plant outlined in earlier sections of this report.

The NWCC also provides data on O&M costs (10,000 MW Cumulative Production Volume in 1997$) as follows:

Management, Insurance, Land use and Property Taxes	0.39 cents/kWh
Unscheduled Maintenance	0.68 cents/kWh
Preventative Maintenance	0.18 cents/kWh
Major Overhaul	0.04 cents/kWh
Total	**1.29 cents/kWh**

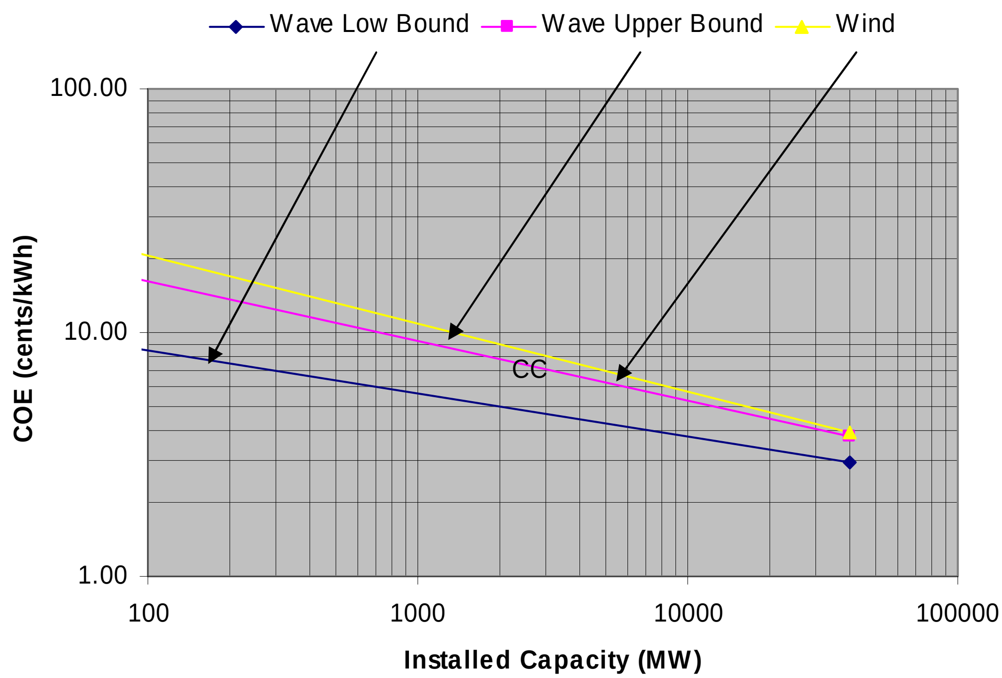

Figure 26: Levelized COE comparison to wind

The learning curve of Figure 26 shows that at worst, the economics of wave energy is about equal to wind energy at any cumulative production volume, and at best, is significantly more economical that wind energy.

Furthermore, this figure shows the effect of the O&M component of COE (the deviation from a straight 82% learning curve) for wave energy. The wave energy industry must drive down O&M costs in order to compete with wind energy at very high cumulative production volumes (>40,0000 MW).

Based on these results, we conclude that had wave energy been subsidized by the Government as it subsidized wind energy, wave energy would be the preferred renewable energy option by private investors today.

13. Conclusions

Pilot Offshore Wave Power Plant

Douglas County, Oregon is a very good area for locating an offshore wave power plant. The county has a growing coastal population and a robust grid interconnection to the coast. The Reedsport – Coos Bay area contains the infrastructure needed to fabricate, assemble and deploy large wave conversion devices as well as operate and maintain them over their life. The Gardiner substation site, leveraging the existing outfall pipe from the International Paper facility and the unused capability of the Gardiner substation equipment, represents a unique opportunity for a feasibility demonstration of a pilot offshore wave energy technology plant in Oregon.

The next steps forward towards implementing a wave energy pilot plant in Douglas County are 1) to assure that the International Paper effluent pipe can be used for the purpose of deploying the transmission cable, 2) to assess local public support local infrastructure interest (marine engineering companies and fabricators), 3) to analyze site-specific environmental effects and 4) to develop a detailed implementation plan for a Phase II (Detailed Design, Environmental Impact Statement, Permitting , Construction Financing and Detailed Implementation Planning for Construction, and Operational Test and Evaluation)

Commercial Scale Offshore Wave Power Plants

The Douglas County Oregon commercial scale power plant design, performance, cost and economics results show that an offshore wave power plant, if learning investments are made to achieve the same degree of learning as today's wind technology, will provide favorable economics compared to wind technology in terms of both COE for a UG and in terms of IRR for a NUG.

As a new and emerging technology, offshore wave power has essentially no production experience and therefore its costs, uncertainties and risks are relatively high compared to existing commercially available technologies such as wind power with a cumulative production experience of about 40,000 MW installed. Private energy investors most probably will not select offshore wave technology when developing new generation because the performance, cost, and risk uncertainties are too high. Feasibility demonstration of wave energy technology is needed to reduce those uncertainities.

Government subsidy learning investments in wave energy technology, both RD&D and deployment are needed to ride down the experience curve to bring prices down to the break even point with wind energy technology. The market will then be transformed and offshore wave energy technology will be able to compete in the market place without further government subsidy (or at a subsidy equal to the wind energy subsidy). The learning effect irreversibly binds tomorrow's options to today's actions. Successful market implementation sets up a positive price-growth cycle; market growth provides learning and reduces price, which makes the product more attractive, supporting further growth which further reduces price. Conversely, a technology which cannot enter the market because it is too expensive will be denied the learning necessary to overcome the cost barrier and therefore the technology will be locked-out from the market.

The learning-curve phenomenon presents the Government policy-maker with both risks and benefits. The risks involve the lock-out of potentially low-cost and environmentally benign technologies. The benefits lie in the creation of new technology options by exploiting the learning effect. However, there is also the risk that expected benefits will not materialize. Learning opportunities in the market and learning investments are both scarce resources. Policy decisions to support market learning for a technology must therefore be based on assessments of the future markets for the technology and its value to the energy system

In a market where price reflects all present and future externalities, we expect the integrated action of the actors to produce an efficient balance of the technology options. The risk of climate change and the social and health costs of some electricity generation options, however, pose an externality which might be very substantial and costly to internalize through price alone. Intervening in the market to support a climate-friendly technology that may otherwise risk lock-out is a legitimate way for the Government policy-maker to manage the externality.

We conclude that offshore wave technology requires a Federal Government learning investment subsidy in order for it to be able to compete with available electricity generation technologies. All electricity generation technologies commercially available today have received Federal Government subsidies in the past. Subsidy of beneficial societal energy options has traditionally not been handled by State Governments. Wave energy technology will not be the first electricity generation technology to reach the commercial market place without Federal Government subsidy. Governments in Europe and the Government of Australia are subsidizing off shore wave energy. Should the U.S. Government drive the cumulative volume up and the price down by funding offshore wave energy technology RD&D and providing deployment subsidies?

Technology Issues

Offshore wave energy electricity generation is a new and emerging technology application. The first time electricity was provided to the electrical grid from an offshore wave power plant occurred in early August, 2004 by the full scale preproduction OPD Pelamis prototype in the UK. Many important questions about the application of offshore wave energy to electricity generation remain to be answered. Some of the key issues which remain to be addressed are:

- There is not a single wave power technology. Rather we are talking about a wide range of wave power technologies and power conversion machines which are currently under development. It is unclear at present what type of technology will yield optimal economics.

- It is also unclear at present at which size these technologies will yield optimal economics. Wave Power devices are typically tuned to prevailing wave conditions. As such optimization is largely driven by the wave climate at the deployment site. Very few existing designs have been optimized for the US wave climate. Wind turbines for example have grown in size from less then 100kW per unit to over 3MW in order to drive down cost.

- Given a certain device type and rating, what capacity factor is optimal for a given site? Ocean waves have a vast range of power levels and optimal power ratings can be only determined using sophisticated techno-economic optimization procedures.

- Will the low intermittency (relative to solar and wind) and the better predictability of wave energy (relative to solar and wind) earn capacity payments for its ability to be dispatched for electricity generation?

- Will the installed cost of wave energy conversion devices realize their potential of being much less expensive per COE than solar or wind (because a wave machine is converting a much more concentrated form of energy than a solar or wind machine and is therefore smaller in size)?

- Will the O&M cost of wave energy conversion devices be as high as predicted in this study and remain much higher than the O&M cost of solar or wind (because of the more remote and harsher environment in which it operates and must be maintained)?

14. Recommendations

Pilot Offshore Wave Power Plant

E2I EPRI makes the following specific recommendations to the Oregon State Electricity Stakeholders:

5. Encourage the ongoing R&D at universities such as Oregon State University (OSU) to include technology cost reduction, improvement in efficiency and reliability, identification of sites, interconnection with the utility grid and study of impacts of the technology on marine life and the shoreline

6. Coordinate efforts to attract a pilot feasibility demonstration wave energy system project to the Oregon coast

7. Now that the Douglas County Oregon pilot demonstration plant project definition study is complete, proceed to the next steps of assessing local public support, local infrastructure interest (marine engineering companies and fabricators), analyzing site-specific environmental effects and developing a detailed implantation plan for a Phase II (Detailed Design, Environmental Impact Statement, Permitting , Construction Financing and Detailed Implementation Planning for Construction, and Operational test and Evaluation)

8. Build collaboration with other states with common interest and goals in offshore wave energy.

Commercial Scale Offshore Wave Power Plants

E2I EPRI makes the following specific recommendations to the Oregon State Electricity Stakeholders relative to a Douglas County Oregon commercial scale offshore wave power plant

1. Understand the implications of Government subsidy of wave energy technology, the use of learning curves to assist in subsidy decision-making and the potential for lock-out of the technology if the Government decides to withhold subsidy from this technology.

If after gaining this understanding, you advocate Government subsidy of offshore wave energy technology:

1. Encourage Dept of Energy leaders to initiate an ocean energy RD&D program.

2. Encourage DOE leaders to participate in the development of offshore wave energy technology (standards, national offshore wave test center, etc).

Technology Issues

In order to stimulate the growth of ocean energy technology in the United States and to address and answer the techno-economic challenges listed in Section 13, we recommend the following take place:

- Federal recognition of ocean energy as a renewable resource, and public recognition by Congress that expansion of an ocean energy industry in the U.S. is a vital national priority.

- Creation of an ocean energy program within the Department of Energy's Energy Efficiency and Renewable Energy division.

- DOE works with the government of Canada on an integrated bi-lateral ocean energy strategy.

- The process for licensing, leasing, and permitting renewable energy facilities in U.S. waters must be streamlined

- Provision of production tax credits, renewable energy credits, and other incentives to spur private investment in Ocean Energy technologies and projects.

- Provision of adequate federal funding for ocean energy R&D and demonstration projects.

- Ensuring that the public receives a fair return from the use of ocean energy resources and that development rights are allocated through an open, transparent process that takes into account state, local, and public concerns.

15. References

1. E2I EPRI WP US 005 "Methodology for Conceptual Level Design of Offshore Wave Power Plants" Mirko Previsic and Roger Bedard, June 9, 2004

2. E2I EPRI WP US 001 "Guidelines for Preliminary Estimation of Power Production by Offshore Wave Energy Conversion Devices" George Hagerman and Roger Bedard, December 22, 2003

3. E2I EPRI WP US 003 "Economic Assessment Methodology for Offshore Wave Energy Power Plants" Rev 2. Mirko Previsic and Roger Bedard, August 16, 2004

4. E2I EPRI WP US 004 "E2I EPRI Assessment Offshore Wave Energy Devices" Rev 1, Mirko Previsic, Roger Bedard and George Hagerman, June 16, 2004

5. "Pelamis WEC – Main Body Structural Design and Material Selection", Department of Trade and Industry (DTI)

6. "Pelamis WEC – Conclusion of Primary R&D", Department of Trade and Industry (DTI)

Appendix A – Monthly Wave Energy Resource Scatter Diagrams

Table A-1: Scatter diagram Oregon January

CDIP 0037 Coquille River		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	744
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									JAN
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
5.75	6.25	6	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	2
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	2	2	0	0	0	0	0	0	4
4.75	5.25	5	0	0	0	0	0	0	1	1	3	2	5	0	0	0	1	0	0	13
4.25	4.75	4.5	0	0	0	0	0	0	1	2	3	9	6	3	0	2	0	1	0	26
3.75	4.25	4	0	0	0	0	0	1	3	5	7	13	14	8	2	3	1	2	0	59
3.25	3.75	3.5	0	0	0	1	1	3	5	6	9	14	21	10	6	4	2	0	0	82
2.75	3.25	3	0	0	0	1	1	2	12	14	17	31	24	9	4	3	1	1	0	120
2.25	2.75	2.5	0	0	0	4	5	7	14	16	20	28	27	9	10	7	1	2	0	149
1.75	2.25	2	0	0	0	1	3	6	19	15	23	33	22	9	6	5	3	3	0	149
1.25	1.75	1.5	0	0	1	2	5	7	12	10	14	15	20	7	6	2	2	1	0	103
0.75	1.25	1	0	0	0	0	0	0	2	4	4	10	7	3	2	0	0	0	0	34
0.25	0.75	0.5	0	0	0	0	0	0	0	3	0	0	0	0	0	0	0	0	0	3
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		744	0	0	2	9	14	25	68	75	100	156	148	58	37	28	12	10	1	744

Table A-2: Scatter Diagram Oregon February

CDIP 0037 Coquille River		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	744
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									JAN
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	2
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	1	1	0	4	2	1	0	9
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	1	5	4	3	1	1	0	0	15
4.75	5.25	5	0	0	0	0	0	0	0	1	0	4	4	6	3	3	1	0	0	22
4.25	4.75	4.5	0	0	0	0	0	0	4	1	4	8	16	7	2	1	0	0	0	43
3.75	4.25	4	0	0	0	0	2	0	6	4	9	21	34	13	4	3	1	2	0	99
3.25	3.75	3.5	0	0	0	0	0	1	11	5	25	30	34	10	4	7	1	1	0	129
2.75	3.25	3	0	0	0	0	2	9	10	28	47	50	41	29	15	12	1	2	0	246
2.25	2.75	2.5	0	0	0	2	4	7	39	33	73	77	65	26	17	8	5	1	0	357
1.75	2.25	2	0	0	2	7	10	13	37	60	72	82	72	28	11	16	14	5	0	429
1.25	1.75	1.5	0	0	1	8	11	8	22	40	31	39	43	12	11	16	8	6	1	257
0.75	1.25	1	0	2	2	2	2	3	15	5	12	14	17	4	3	5	1	0	0	87
0.25	0.75	0.5	0	0	0	0	0	0	0	0	0	2	5	1	0	2	0	0	0	10
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		1,705	0	2	5	19	31	41	144	177	273	328	338	142	73	78	35	18	1	1,705

Table A-3: Scatter Diagram Oregon March

CDIP 0037 Coquille River		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	744
		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									JAN
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	1
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	1	3	0	0	1	0	0	5
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	3	5	1	2	0	0	0	11
4.25	4.75	4.5	0	0	0	0	0	0	0	0	1	5	11	11	3	1	1	0	0	33
3.75	4.25	4	0	0	0	0	0	1	4	9	6	9	31	9	4	5	4	0	0	82
3.25	3.75	3.5	0	0	0	0	0	4	1	3	17	19	52	10	6	5	3	2	0	122
2.75	3.25	3	0	0	0	1	8	7	15	19	34	49	55	22	8	7	3	5	0	233
2.25	2.75	2.5	0	0	0	2	6	16	45	33	46	64	36	20	13	13	5	4	1	304
1.75	2.25	2	0	0	1	7	21	31	84	74	82	87	63	32	33	20	15	9	0	559
1.25	1.75	1.5	0	0	8	16	16	29	85	76	52	56	41	22	17	10	12	5	0	445
0.75	1.25	1	0	1	2	4	7	13	17	19	14	19	12	10	6	0	0	1	0	125
0.25	0.75	0.5	0	0	0	1	0	0	7	3	2	7	2	2	0	0	0	0	0	24
0	0.25	0.125	0	0	0	0	0	2	13	1	1	0	0	0	0	0	0	0	0	17
		1,961	0	1	11	31	58	103	271	237	255	315	307	147	91	63	44	26	1	1,961

Table A-4: Scatter Diagram Oregon April

CDIP 0037		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	744
Coquille River		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									JAN
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	2	1	0	1	0	0	4
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	1	1	0	0	2	0	0	4
4.75	5.25	5	0	0	0	0	0	0	0	0	0	1	7	3	1	1	1	1	0	15
4.25	4.75	4.5	0	0	0	0	0	0	0	0	1	3	7	8	3	3	0	1	0	26
3.75	4.25	4	0	0	0	0	0	0	1	3	2	12	17	6	5	0	5	6	0	57
3.25	3.75	3.5	0	0	0	0	0	3	2	4	9	12	31	10	4	5	6	7	0	93
2.75	3.25	3	0	0	0	1	5	7	18	18	27	51	37	17	7	4	1	0	2	195
2.25	2.75	2.5	0	0	0	9	17	17	56	31	61	61	49	12	4	7	4	0	0	328
1.75	2.25	2	0	0	2	8	21	54	78	88	83	80	57	7	2	9	4	0	0	493
1.25	1.75	1.5	0	0	2	8	24	59	103	136	53	66	31	17	6	5	2	2	2	516
0.75	1.25	1	0	0	2	6	16	20	53	91	34	25	21	8	3	5	0	1	1	286
0.25	0.75	0.5	0	0	0	0	1	3	2	1	2	0	3	1	0	0	0	0	0	13
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		2,030	0	0	6	32	84	163	313	372	272	311	261	92	36	39	26	18	5	2,030

Table A-5: Scatter Diagram Oregon May

CDIP 0037		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	744
Coquille River		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									JAN
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.25	4.75	4.5	0	0	0	0	0	0	0	1	0	2	1	0	0	0	0	0	0	4
3.75	4.25	4	0	0	0	0	0	0	0	2	0	3	3	0	1	0	0	0	0	9
3.25	3.75	3.5	0	0	0	0	0	0	1	2	5	6	4	1	1	0	0	0	0	20
2.75	3.25	3	0	0	0	0	0	6	8	12	18	18	11	4	0	1	2	0	0	80
2.25	2.75	2.5	0	0	0	2	7	23	61	32	34	31	20	6	4	0	5	0	0	225
1.75	2.25	2	0	0	2	16	36	65	117	81	66	47	31	4	8	5	1	1	0	480
1.25	1.75	1.5	0	1	10	20	45	119	153	112	62	53	43	18	7	15	7	2	0	667
0.75	1.25	1	0	1	18	18	60	86	82	107	33	13	19	9	4	7	0	0	0	457
0.25	0.75	0.5	0	0	0	4	0	3	9	13	1	0	1	1	1	2	0	0	0	35
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		1,977	0	2	30	60	148	302	431	362	219	173	133	43	26	30	15	3	0	1,977

Table A-6: Scatter Diagram Oregon June

CDIP 0037		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	744
Coquille River		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									JAN
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.25	4.75	4.5	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	1
3.75	4.25	4	0	0	0	0	0	0	0	0	1	2	4	1	0	0	0	0	0	8
3.25	3.75	3.5	0	0	0	0	0	0	0	0	2	4	3	3	1	0	0	0	0	13
2.75	3.25	3	0	0	0	0	0	0	5	3	12	21	15	2	0	0	0	0	0	58
2.25	2.75	2.5	0	0	0	0	2	8	25	25	23	18	9	1	0	0	0	0	0	111
1.75	2.25	2	0	0	0	17	48	58	91	49	39	22	22	1	0	0	2	0	0	349
1.25	1.75	1.5	0	1	6	52	117	123	156	69	23	13	8	2	2	2	2	0	0	576
0.75	1.25	1	0	4	21	62	103	113	95	120	30	23	9	15	10	9	1	1	0	616
0.25	0.75	0.5	0	0	1	7	19	20	2	26	0	0	10	15	4	7	0	0	0	111
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		1,843	0	5	28	138	289	322	374	292	130	104	80	40	17	18	5	1	0	1,843

Table A-7: Scatter Diagram Oregon July

CDIP 0037		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	744
Coquille River		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									JAN
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	2	1	0	1	0	0	4
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	1	1	0	0	2	0	0	4
4.75	5.25	5	0	0	0	0	0	0	0	0	0	1	7	3	1	1	1	1	0	15
4.25	4.75	4.5	0	0	0	0	0	0	0	0	1	3	7	8	3	3	0	1	0	26
3.75	4.25	4	0	0	0	0	0	0	1	3	2	12	17	6	5	0	5	6	0	57
3.25	3.75	3.5	0	0	0	0	0	3	2	4	9	12	31	10	4	5	6	7	0	93
2.75	3.25	3	0	0	0	1	5	7	18	18	27	51	37	17	7	4	1	0	2	195
2.25	2.75	2.5	0	0	0	9	17	17	56	31	61	61	49	12	4	7	4	0	0	328
1.75	2.25	2	0	0	2	8	21	54	78	88	83	80	57	7	2	9	4	0	0	493
1.25	1.75	1.5	0	0	2	8	24	59	103	136	53	66	31	17	6	5	2	2	2	516
0.75	1.25	1	0	0	2	6	16	20	53	91	34	25	21	8	3	5	0	1	1	286
0.25	0.75	0.5	0	0	0	0	1	3	2	1	2	0	3	1	0	0	0	0	0	13
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		2,030	0	0	6	32	84	163	313	372	272	311	261	92	36	39	26	18	5	2,030

Table A-8: Scatter Diagram Oregon August

CDIP 0037		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	744
Coquille River		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									JAN
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.25	4.75	4.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.75	4.25	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3.25	3.75	3.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2.75	3.25	3	0	0	0	0	0	0	1	2	0	0	0	0	0	0	0	0	0	4
2.25	2.75	2.5	0	0	0	0	0	6	5	3	1	0	0	0	0	0	0	0	0	14
1.75	2.25	2	0	0	0	3	8	18	24	9	5	3	1	0	0	0	0	0	0	70
1.25	1.75	1.5	0	0	3	30	50	65	60	33	6	4	3	0	0	0	0	0	0	253
0.75	1.25	1	0	0	10	49	85	76	50	30	10	7	10	4	1	1	0	0	0	333
0.25	0.75	0.5	0	0	4	7	10	9	3	17	4	3	9	3	2	1	1	0	0	70
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		744	0	0	16	89	152	173	142	94	26	16	22	6	3	2	1	0	0	744

Table A-9: Scatter Diagram Oregon September

CDIP 0037		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	744
Coquille River		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries											Tp (sec)									JAN
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4.75	5.25	5	0	0	0	0	0	0	0	0	0	3	1	3	0	0	0	0	0	7
4.25	4.75	4.5	0	0	0	0	0	0	0	0	0	4	0	0	0	0	0	0	0	4
3.75	4.25	4	0	0	0	0	0	0	0	0	0	1	1	2	1	0	0	0	0	5
3.25	3.75	3.5	0	0	0	0	0	0	0	1	2	2	4	1	1	0	1	0	0	12
2.75	3.25	3	0	0	0	0	0	0	1	6	6	8	4	4	4	3	1	1	0	38
2.25	2.75	2.5	0	0	0	0	1	11	18	33	23	36	19	12	7	4	5	2	0	171
1.75	2.25	2	0	0	0	16	44	62	79	58	54	71	40	8	4	2	6	3	6	453
1.25	1.75	1.5	0	0	14	76	151	138	177	136	84	74	46	26	18	6	1	0	0	947
0.75	1.25	1	1	7	31	59	131	186	179	151	78	24	27	26	20	16	11	3	0	950
0.25	0.75	0.5	0	0	3	4	16	7	11	33	5	6	2	3	2	0	5	1	0	98
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		2,685	1	7	48	155	343	404	465	418	252	229	144	85	57	31	30	10	6	2,685

Table A-10: Scatter Diagram Oregon October

CDIP 0037		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	744
Coquille River		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries			Tp (sec)																	JAN
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	1
5.75	6.25	6	0	0	0	0	0	0	0	0	1	2	3	0	0	0	0	0	0	6
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0	3
4.75	5.25	5	0	0	0	0	0	0	0	0	0	2	6	3	1	0	0	0	0	12
4.25	4.75	4.5	0	0	0	0	0	0	0	2	4	4	4	1	0	0	0	0	0	15
3.75	4.25	4	0	0	0	0	0	0	0	2	9	6	12	4	2	0	0	0	0	35
3.25	3.75	3.5	0	0	0	0	0	0	2	8	21	21	19	7	2	0	0	0	0	80
2.75	3.25	3	0	0	0	0	1	3	13	18	37	48	43	10	3	0	0	0	0	176
2.25	2.75	2.5	0	0	0	3	6	4	34	70	68	77	64	13	7	6	1	0	0	353
1.75	2.25	2	0	0	3	16	23	34	114	94	113	96	80	29	15	12	5	2	0	636
1.25	1.75	1.5	0	0	7	35	53	99	162	118	127	96	41	17	16	16	7	6	1	801
0.75	1.25	1	0	3	11	14	31	57	101	115	58	39	20	13	11	9	3	6	0	491
0.25	0.75	0.5	1	1	2	6	4	6	7	19	2	2	2	1	4	0	0	0	0	57
0	0.25	0.125	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	2
		2,668	1	4	24	75	118	203	433	446	440	394	296	99	61	43	16	14	1	2,668

Table A-11: Scatter Diagram Oregon November

CDIP 0037		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	744
Coquille River		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries			Tp (sec)																	JAN
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5.75	6.25	6	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	2
5.25	5.75	5.5	0	0	0	0	0	0	0	0	0	2	2	3	0	0	0	0	0	7
4.75	5.25	5	0	0	0	0	0	0	1	1	4	5	5	5	2	2	0	0	0	25
4.25	4.75	4.5	0	0	0	0	0	0	2	4	7	6	9	6	1	4	0	0	0	39
3.75	4.25	4	0	0	0	0	1	0	6	3	5	2	13	6	4	1	0	0	1	42
3.25	3.75	3.5	0	0	0	0	1	3	10	15	21	38	33	11	5	0	0	0	0	137
2.75	3.25	3	0	0	0	0	4	4	21	37	58	63	56	17	3	2	0	0	0	265
2.25	2.75	2.5	0	0	1	4	7	10	43	59	72	90	54	17	8	7	3	1	0	376
1.75	2.25	2	0	0	2	14	14	13	61	94	116	62	29	9	6	7	9	2	0	438
1.25	1.75	1.5	0	0	1	5	6	32	70	79	62	53	43	9	4	2	3	1	1	371
0.75	1.25	1	0	1	3	1	8	34	20	36	7	17	30	7	9	7	5	0	0	185
0.25	0.75	0.5	0	1	0	0	2	1	1	0	8	1	1	1	0	0	0	0	0	16
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		1,903	0	2	7	24	43	97	235	328	360	339	276	92	42	32	20	4	2	1,903

Table A-12: Scatter Diagram Oregon December

CDIP 0037		Upper Tp:	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	18.5	20.5	744
Coquille River		Lower Tp:	2.5	3.5	4.5	5.5	6.5	7.5	8.5	9.5	10.5	11.5	12.5	13.5	14.5	15.5	16.5	17.5	19.5	Total
Hs and Tp bin boundaries			Tp (sec)																	JAN
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	hours
9.75	10.25	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9.25	9.75	9.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.75	9.25	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8.25	8.75	8.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.75	8.25	8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7.25	7.75	7.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6.75	7.25	7	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	1
6.25	6.75	6.5	0	0	0	0	0	0	0	0	0	1	1	2	1	0	0	0	0	4
5.75	6.25	6	0	0	0	0	0	0	1	0	1	1	1	0	1	2	0	0	0	6
5.25	5.75	5.5	0	0	0	0	0	0	0	0	1	1	1	1	1	0	0	0	0	3
4.75	5.25	5	0	0	0	0	0	0	1	1	1	2	7	1	2	1	0	0	0	14
4.25	4.75	4.5	0	0	0	0	0	0	0	1	1	8	15	3	2	1	0	0	0	29
3.75	4.25	4	0	0	0	0	0	0	1	1	6	15	15	5	5	2	1	1	1	51
3.25	3.75	3.5	0	0	0	1	0	1	4	2	7	15	22	5	7	3	4	2	0	74
2.75	3.25	3	0	0	0	0	1	2	7	6	14	21	20	11	7	3	3	2	0	94
2.25	2.75	2.5	0	0	0	2	3	7	11	11	18	30	32	7	6	4	2	1	2	134
1.75	2.25	2	0	0	1	2	2	7	23	18	24	34	30	11	3	1	1	1	2	160
1.25	1.75	1.5	0	0	1	4	2	4	13	22	17	25	24	7	3	0	1	0	0	122
0.75	1.25	1	0	0	0	1	0	3	3	9	2	5	8	3	4	6	3	1	0	48
0.25	0.75	0.5	0	0	0	0	0	1	1	0	1	0	0	1	0	0	1	0	0	4
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		744	0	0	1	9	7	25	64	70	92	156	175	55	42	22	15	7	4	744

Appendix B Commercial Plant Cost Economics Worksheet – Regulated Utility

INSTRUCTIONS

Indicates Input Cell (either input or use default values)

Indicates a Calculated Cell (do not input any values)

Sheet 1. TPC/TPI (Total Plant Cost/Total Plant Investment)

a) Enter Component Unit Cost and No. of Units per System
b) Worksheet sums component costs to get TPC
c) Adds the value of the construction loan payments to get TPI

Sheet 2. AO&M (Annual operation and Maintenance Cost)

a) Enter Labor Hrs and Cost by O&M Type)
b) Enter Parts and Supplies Cost by O&M Type)
c) Worksheet Calculates Total Annual O&M Cost

Sheet 3. O&R (Overhaul and Replacement Cost)

a) Enter Year of Cost and O&R Cost per Item
b) Worksheets calculates the present value of the O&R costs

Sheet 4. Assumptions (Financial)

a) Enter project and financial assumptions or leave default values

Sheet 5. NPV (Net Present Value)

A Gross Book Value = TPI
B Annual Book Depreciation = Gross Book Value/Book Life
C Cumulative Depreciation
D MACRS 5 Year Depreciation Tax Schedule Assumption
E Deferred Taxes = (Gross Book Value X MACRS Rate - Annual Book Depreciation) X Debt Financing Rate
F Net Book Value = Previous Year Net Book Value - Annual Book Depreciation - Deferred Tax for that Year

Sheet 6. CRR (Capital Revenue Requirements)

A Net Book Value for Column F of NPV Worksheet
B Common Equity = Net Book X Common Equity Financing Share X Common Equity Financing Rate
C Preferred Equity = Net Book X Preferred Equity Financing Share X Preferred Equity Financing Rate
D Debt = Net Book X Debt Financing Share X Debt Financing Rate
E Annual Book Depreciation = Gross Book Value/Book Life
F Income Taxes = (Return on Common Equity + Return of Preferred Equity - Interest on Debt + Deferred Taxes) X (Comp Tax Rate/(1-Comp Tax Rate))
G Property Taxes and Insurance Expense =
H Calculates Investment and Production Tax Credit Revenues
I Capital Revenue Req'ts = Sum of Columns B through G

Sheet 7. FCR (Fixed Charge Rate)

A Nominal Rates Capital Revenue Req'ts from Colunmn H of Previous Worksheet
B Nominal Rate Present Worth Factor = 1 / (1 + After Tax Discount Rate)
C Nominal Rate Product of Columns A and B = A * B
D Real Rates Capital Revenue Req'ts from Colunmn H of Previous Worksheet
E Real Rates Present Worth Factor = 1 / (1 + After Tax Discount Rate - Inflation Rate)
F Real Rates Product of Columns A and B = A * B

Sheet 8. Calculates COE (Cost of Electricity)

COE = ((TPI * FCR) + AO&M + LO&R) / AEP

In other words…The Cost of Electricity =

The Sum of the Levelized Plant Investment + Annual O&M Cost + Levelized Overhaul and Replacement Cost Divided by the Annual Electric Energy Consumption

TOTAL PLANT COST (TPC) - 2004$

TPC Component	Unit	Unit Cost	Total Cost (2004$)	
Procurement				
Onshore Trans & Grid I/C	1	$2,500,000	$2,500,000	
Subsea Cables	1	$1,850,000	$1,850,000	
Mooring	180	$117,247	$21,104,460	
Power Conversion Modules (set of 3)	180	$623,960	$112,312,800	
Concrete Structure Sections	180	$244,800	$44,064,000	
Facilities	1	$12,000,000	$12,000,000	
Installation	1	$11,301,000	$11,301,000	
Construction Management	1	$9,691,000	$9,691,000	
TOTAL			$214,823,260	

TOTAL PLANT INVESTMENT (TPI) - 2004 $

End of Year	Total Cash Expended TPC (2004$)	Before Tax Construction Loan Cost at Debt Financing Rate	2004 Value of Construction Loan Payments	TOTAL PLANT INVESTMENT 2004$
2006	$107,411,630	$8,055,872	$7,273,925	$114,685,555
2007	$107,411,630	$16,111,745	$13,135,757	$120,547,387
Total	$214,823,260	$24,167,617	$20,409,682	$235,232,942

ANNUAL OPERATING AND MAINTENANCE COST (AO&M) - 2004$

Costs	Yrly Cost	Amount	
LABOR	$2,322,000	$2,322,000	
PARTS AND SUPPLIES (2%)	$4,296,000	$4,296,000	
INSURANCE (2%)	$4,296,000	$4,296,000	
Total		$10,914,000	

OVERHAUL AND REPLACEMENT COST (OAR) - 2004$

O&R Costs	Year of Cost	Cost in 2004$	
10 Year Retrofit			
Operation	10	$9,758,000	
Parts	10	$13,776,000	
Total		$23,534,000	

FINANCIAL ASSUMPTIONS

(default assumptions in pink background - without line numbers are calculated values)

1	Rated Plant Capacity ©	90	MW
2	Annual Electric Energy Production (AEP)	300,000	MWeh/yr
	Therefore, Capacity Factor	38.03	%
3	Year Constant Dollars	2004	Year
4	Federal Tax Rate	35	%
5	State	Oregon	
6	State Tax Rate	6.6	%
	Composite Tax Rate (t)	0.3929	
	t/(1-t)	0.6472	
7	Book Life	20	Years
8	Construction Financing Rate	7.5	
9	Common Equity Financing Share	52	%
10	Preferred Equity Financing Share	13	%
11	Debt Financing Share	35	%
12	Common Equity Financing Rate	13	%
13	Preferred Equity Financing Rate	10.5	%
14	Debt Financing Rate	7.5	%
	Nominal Discount Rate Before-Tax	10.75	%
	Nominal Discount Rate After-Tax	9.72	%
15	Inflation Rate = 3%	3	%
	Real Discount Rate Before-Tax	7.52	%
	Real Discount Rate After-Tax	6.52	%
16	Federal Investment Tax Credit	10	% 1st year onl
17	Federal Production Tax Credit	0.018	$/kWh for 1st
18	State Investment Tax Credit	25	% of TPI up tc
19	State Investment Tax Credit Limit	$2,500,000	Credit - 1st ye $10M plant
20	State Production Tax Credit	0	$/kWh for 1st

NET PRESENT VALUE (NPV) - 2004 $

TPI = $235,232,942

Year End	Gross Book Value	Book Depreciation Annual	Book Depreciation Accumulated	Renewable Resource MACRS Tax Depreciation Schedule	Deferred Taxes	Net Book Value
	A	B	C	D	E	F
2007	**235,232,942**					**235,232,942**
2008	235,232,942	11,761,647	11,761,647	0.2000	13,863,453	209,607,841
2009	235,232,942	11,761,647	23,523,294	0.3200	24,954,216	172,891,978
2010	235,232,942	11,761,647	35,284,941	0.1920	13,124,069	148,006,262
2011	235,232,942	11,761,647	47,046,588	0.1152	6,025,981	130,218,634
2012	235,232,942	11,761,647	58,808,235	0.1152	6,025,981	112,431,005
2013	235,232,942	11,761,647	70,569,883	0.0576	702,415	99,966,943
2014	235,232,942	11,761,647	82,331,530	0.0000	-4,621,151	92,826,447
2015	235,232,942	11,761,647	94,093,177	0.0000	-4,621,151	85,685,951
2016	235,232,942	11,761,647	105,854,824	0.0000	-4,621,151	78,545,455
2017	235,232,942	11,761,647	117,616,471	0.0000	-4,621,151	71,404,960
2018	235,232,942	11,761,647	129,378,118	0.0000	-4,621,151	64,264,464
2019	235,232,942	11,761,647	141,139,765	0.0000	-4,621,151	57,123,968
2020	235,232,942	11,761,647	152,901,412	0.0000	-4,621,151	49,983,472
2021	235,232,942	11,761,647	164,663,059	0.0000	-4,621,151	42,842,976
2022	235,232,942	11,761,647	176,424,706	0.0000	-4,621,151	35,702,480
2023	235,232,942	11,761,647	188,186,354	0.0000	-4,621,151	28,561,984
2024	235,232,942	11,761,647	199,948,001	0.0000	-4,621,151	21,421,488
2025	235,232,942	11,761,647	211,709,648	0.0000	-4,621,151	14,280,992
2026	235,232,942	11,761,647	223,471,295	0.0000	-4,621,151	7,140,496
2027	235,232,942	11,761,647	235,232,942	0.0000	-4,621,151	0

TPI = $235,232,942

End of Year	Net Book	Returns to Equity Common	Returns to Equity Pref	Interest on Debt	Book Dep	Income Tax on Equity Return	ITC and PTC	Capital Revenue Req'ts
	A	B	C	D	E	F	H	I
2008	209,607,841	14,169,490	2,861,147	5,502,206	11,761,647	16,432,995	28,948,294	21,779,191
2009	172,891,978	11,687,498	2,359,976	4,538,414	11,761,647	22,303,773	5,400,000	47,251,308
2010	148,006,262	10,005,223	2,020,285	3,885,164	11,761,647	13,761,799	5,400,000	36,034,119
2011	130,218,634	8,802,780	1,777,484	3,418,239	11,761,647	8,534,949	5,400,000	28,895,099
2012	112,431,005	7,600,336	1,534,683	2,951,314	11,761,647	7,901,805	5,400,000	26,349,785
2013	99,966,943	6,757,765	1,364,549	2,624,132	11,761,647	4,012,872	5,400,000	21,120,965
2014	92,826,447	6,275,068	1,267,081	2,436,694	11,761,647	313,429	5,400,000	16,653,919
2015	85,685,951	5,792,370	1,169,613	2,249,256	11,761,647	59,266	5,400,000	15,632,153
2016	78,545,455	5,309,673	1,072,145	2,061,818	11,761,647	-194,897	5,400,000	14,610,386
2017	71,404,960	4,826,975	974,678	1,874,380	11,761,647	-449,061	5,400,000	13,588,619
2018	64,264,464	4,344,278	877,210	1,686,942	11,761,647	-703,224		17,966,853
2019	57,123,968	3,861,580	779,742	1,499,504	11,761,647	-957,387		16,945,086
2020	49,983,472	3,378,883	682,274	1,312,066	11,761,647	-1,211,551		15,923,320
2021	42,842,976	2,896,185	584,807	1,124,628	11,761,647	-1,465,714		14,901,553
2022	35,702,480	2,413,488	487,339	937,190	11,761,647	-1,719,877		13,879,786
2023	28,561,984	1,930,790	389,871	749,752	11,761,647	-1,974,041		12,858,020
2024	21,421,488	1,448,093	292,403	562,314	11,761,647	-2,228,204		11,836,253
2025	14,280,992	965,395	194,936	374,876	11,761,647	-2,482,367		10,814,486
2026	7,140,496	482,698	97,468	187,438	11,761,647	-2,736,531		9,792,720
2027	0	0	0	0	11,761,647	-2,990,694		8,770,953
Sum of Annual Capital Revenue Requirements								375,604,576

FIXED CHARGE RATE (FCR) - NOMINAL AND REAL LEVELIZED

TPI = $235,232,942

End of Year	Capital Revenue Req'ts Nominal A	Present Worth Factor Nominal B	Product of Columns A and B C	Capital Revenue Req'ts Real D	Present Worth Factor Real E	Product of Columns D and E F
2008	21,779,191	0.9114	19,850,038	19,931,045	0.9388	18,710,565
2009	47,251,308	0.8307	39,251,208	41,982,175	0.8813	36,998,028
2010	36,034,119	0.7571	27,281,779	31,083,348	0.8273	25,715,694
2011	28,895,099	0.6900	19,938,963	24,199,191	0.7767	18,794,385
2012	26,349,785	0.6289	16,572,005	21,424,787	0.7291	15,620,704
2013	21,120,965	0.5732	12,106,855	16,673,085	0.6844	11,411,872
2014	16,653,919	0.5224	8,700,688	12,763,842	0.6425	8,201,233
2015	15,632,153	0.4762	7,443,472	11,631,790	0.6032	7,016,186
2016	14,610,386	0.4340	6,340,712	10,554,854	0.5663	5,976,729
2017	13,588,619	0.3955	5,374,911	9,530,784	0.5316	5,066,369
2018	17,966,853	0.3605	6,477,204	12,234,553	0.4990	6,105,386
2019	16,945,086	0.3286	5,567,740	11,202,698	0.4685	5,248,129
2020	15,923,320	0.2995	4,768,572	10,220,573	0.4398	4,494,836
2021	14,901,553	0.2729	4,067,297	9,286,155	0.4129	3,833,817
2022	13,879,786	0.2488	3,452,842	8,397,499	0.3876	3,254,635
2023	12,858,020	0.2267	2,915,329	7,552,731	0.3638	2,747,977
2024	11,836,253	0.2066	2,445,949	6,750,050	0.3416	2,305,541
2025	10,814,486	0.1883	2,036,848	5,987,719	0.3206	1,919,924
2026	9,792,720	0.1717	1,681,031	5,264,069	0.3010	1,584,533
2027	8,770,953	0.1565	1,372,267	4,577,495	0.2826	1,293,493
	375,604,576		197,645,708	281,248,443		186,300,036

	Nominal $		Real $
1. The present value is at the beginning of 2006 and results from the sum of the products of the annual present value factors times the annual requirements	197,645,708		186,300,036
2. Escalation Rate	3%		3%
3. After Tax Discount Rate = i	9.72%		6.52%
4. Capital recovery factor value = i(1+i)"/(1+i)"-1 where book life = n and discount rate = i	0.115211964		0.090921903
5. The levelized annual charges (end of year) = Present Value (Item 1) * Capital Recovery Factor (Item 4)	22,771,150		16,938,754
6. Booked Cost	235,232,942		235,232,942
7. The levelized annual fixed charge rate (levelized annual charges divided by the booked cost)	**0.0968**		**0.0720**

LEVELIZED COST OF ELECTRICITY CALCULATION - UTILITY GENERATOR

COE = ((TPI * FCR) + AO&M + LO&R) / AEP
In other words…
The Cost of Electricity =

The Sum of the Levelized Plant Investment + Annual O&M Cost + Levelized Overhaul and Replacement Cost
Divided by the Annual Electric Energy Consumption

NOMINAL RATES

	Value	Units	From
TPI	$235,232,942	$	From TPI
FCR	9.68%	%	From FCR
AO&M	$10,914,000	$	From AO&M
LO&R = O&R/Life	$1,176,700	$	From LO&R
AEP =	300,000	MWeh/yr	From Assumptions
COE - TPI X FCR	7.59	cents/kWh	
COE - AO&M	3.64	cents/kWh	
COE - LO&R	0.39	cents/kWh	
COE	$0.1162	$/kWh	Calculated
COE	**11.62**	cents/kWh	Calculated

REAL RATES

	Value	Units	From
TPI	$235,232,942	$	From TPI
FCR	7.20%	%	From FCR
AO&M	$10,914,000	$	From AO&M
LO&R = O&R/Life	$1,176,700	$	From LO&R
AEP =	300,000	MWeh/yr	From Assumptions
COE - TPI X FCR	5.65	cents/kWh	
COE - AO&M	3.64	cents/kWh	
COE - LO&R	0.39	cents/kWh	
COE	$0.0968	$/kWh	Calculated
COE	**9.68**	cents/kWh	Calculated

Appendix C Commercial Plant Cost Economics Worksheet – NUG

INSTRUCTIONS

Fill in first four worksheets (or use default values) - the last two worksheets are automatically calculated. Refer to E2I EPRI Economic Methodology Report 004 Rev 2

Indicates Input Cell (either input or use default values)

Indicates a Calculated Cell (do not input any values)

Sheet 1. Total Plant Cost/Total Plant Investment (TPC/TPI) - 2004$

1 Enter Component Unit Cost and No. of Units per System
2 Worksheet sums component costs to get TPC
3 Worksheet adds the value of the construction loan payments to get TPI

Sheet 2. AO&M (Annual Operation and Maintenance Cost) - 2004$

1 Enter Labor Hrs and Cost by O&M Type)
2 Enter Parts and Supplies Cost by O&M Type)
3 Worksheet Calculates Total Annual O&M Cost

Sheet 3. O&R (Overhaul and Replacement Cost) - 2004$

1 Enter Year of Cost and O&R Cost per Item
2 Worksheet calculates inflation to the year of the cost of the O&R

Sheet 4. Assumptions (Project, Financial and Others)

1 Enter project, financial and other assumptions or leave default values

Sheet 5. Income Statement - Assuming no capacity factor income - Current $

1 2008 Energy payments(2002-2008) = AEP X 2002 wholesale price X 92% (to adjust price from 2002 to 2008 (an 8% decline) X Inflation from 2002 to 2008
2009-2011 Energy payments = 2008 Energy Payment X Inflation
2012-2027 Energy payments = 2011 Energy Price X 0.3% Price escalation X Inflation
2 Calculates State Investment and Producient tax credit
3 Calculates Federal Investment and Production Tax Credit
4 Scheduled O&M from TPC worksheet with inflation
5 Scheduled O&R from TPC worksheet with inflation
8 Earnings before EBITDA = total revenues less total operating costs
9 Tax Depreciation = Assumed MACRS rate X TPI
10 Interest paid = Annual interest given assumed debt interest rate and life of loan
11 Taxable earnings = Tax Depreciation + Interest Paid
12 State Tax = Taxable Earnings x state tax rate
13 Federal Tax = (Taxable earnings - State Tax) X Federal tax rate
14 Total Tax Obligation = Total State + Federal Tax

Sheet 6. Cash Flow Statement - Current $

1 EBITDA
2 Taxes Paid
3 Cash Flow From Operations = EBITDA - Taxes Paid
4 Debt Service = Principal + Interest paid on the debt loan
5 Net Cash Flow after Tax
Year of Start of Ops minus 1 = Equity amount
Year of Start of Ops = Cash flow from ops - debt service
Year of Start of Ops Plus 1 to N = Cash flow from ops - debt service
6 Cum Net Cash Flow After Taxes = previous year net cash flow + current year net cash flow
7 Cum IRR on net cash Flow After Taxes = discount rate that sets the present worth of the net cash flows over the book life equal to the equity investment at the commercial operations

TOTAL PLANT COST (TPC) - 2004$

TPC Component	Unit	Unit Cost	Total Cost (2004$)	Notes and Assumptions
Procurement				
Onshore Trans & Grid I/C	1	$2,500,000	$2,500,000	
Subsea Cables	1	$1,850,000	$1,850,000	
Mooring	180	$117,247	$21,104,460	
Power Conversion Modules (set of 3)	180	$623,960	$112,312,800	
Concrete Structure Sections	180	$244,800	$44,064,000	
Facilities	1	$12,000,000	$12,000,000	
Installation	1	$11,301,000	$11,301,000	
Construction Management	1	$9,691,000	$9,691,000	
TOTAL			$214,823,260	

TOTAL PLANT INVESTMENT (TPI) - 2004 $

End of Year	Total Cash Expended TPC ($2004)	Before Tax Construction Loan Cost at Debt Financing Rate	2004 Value of Construction Loan Payments	TOTAL PLANT INVESTMENT (TPC + Loan Value) ($2004)
2006	$107,411,630	$8,592,930	$7,762,358	$115,173,988
2007	$107,411,630	$17,185,861	$14,024,134	$121,435,764
Total	$214,823,260	$25,778,791	$21,786,492	$236,609,752

ANNUAL OPERATING AND MAINTENANCE COST (AO&M) - 2004$

Costs	Yrly Cost	Amount
LABOR	$2,322,425	$2,322,425
PARTS AND SUPPLIES	$4,295,752	$4,295,752
INSURANCE	$4,295,752	$4,295,752
Total		$10,913,929

OVERHAUL AND REPLACEMENT COST (LOAR) -

O&R Costs	Year of Cost	Cost in 2004$	Cost Inflated to 2018$
10 Year Retrofit			
Operation	10	$9,758,321	$14,760,336
Parts	10	$13,776,280	$20,837,860
Total		$23,534,601	$35,598,196

FINANCIAL ASSUMPTIONS

(default assumptions in pink background - without line numbers are calculated values)

1	Rated Plant Capacity ©	90	MW
2	Annual Electric Energy Production (AEP)	300,000	MWeh/yr
	Therefore, Capacity Factor	38.03	%
3	Year Constant Dollars	2004	Year
4	Federal Tax Rate	35	%
5	State	Oregon	
6	State Tax Rate	6.6	%
	Composite Tax Rate (t)	0.3929	%
	t/(1-t)	0.6472	
7	Book Life	20	Years
8	Construction Financing Rate	8	
9	Common Equity Financing Share	30	%
10	Preferred Equity Financing Share	0	%
11	Debt Financing Share	70	%
12	Common Equity Financing Rate	17	%
13	Preferred Equity Financing Rate	0	%
14	Debt Financing Rate	8	%
	Current $ Discount Rate Before-Tax	10.7	%
	Current $ Discount Rate After-Tax	8.50	%
15	Inflation rate	3	%
16	Federal Investment Tax Credit	10	% 1st year only
17	Federal Production Tax Credit	0.018	$/kWh for 1st 10 yrs
18	State Investment Tax Credit	25	% of TPI up to $2.5M
		$2,500,000	Credit - 1st year only
19	Renewable Energy Certificate	0.000	$/kWh
20	Industrial electricity price - 2002$	0.047	$/kWh
21	Decline in wholesale elec. price from 2002 to 2008	8	%
23	MACRS Year 1	0.2000	
24	MACRS Year 2	0.3200	
25	MACRS Year 3	0.1920	
26	MACRS Year 4	0.1152	
27	MACRS Year 5	0.1152	
28	MACRS Year 6	0.0576	

INCOME STATEMENT ($) **CURRENT DOLLARS**

Description/Year	2008	2009	2010	2011	2012	2013	2014	2015
REVENUES								
Energy Payments	15,489,246	15,953,924	16,432,541	16,925,518	17,485,583	18,064,181	18,661,925	19,279,448
Renewable Energy Certificates	0	0	0	0	0	0	0	0
Federal ITC and PTC	29,060,975	5,400,000	5,400,000	5,400,000	5,400,000	5,400,000	5,400,000	5,400,000
TOTAL REVENUES	44,550,222	21,353,924	21,832,541	22,325,518	22,885,583	23,464,181	24,061,925	24,679,448
AVG $/KWH	0.149	0.071	0.073	0.074	0.076	0.078	0.080	0.082
OPERATING COSTS								
Scheduled and Unscheduled O&M	12,283,803	12,652,317	13,031,887	13,422,843	13,825,529	14,240,295	14,667,503	15,107,528
Scheduled O&R	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0
TOTAL	12,283,803	12,652,317	13,031,887	13,422,843	13,825,529	14,240,295	14,667,503	15,107,528
EBITDA	32,266,418	8,701,607	8,800,655	8,902,674	9,060,054	9,223,887	9,394,421	9,571,919
Tax Depreciation	47,321,950	75,715,121	45,429,072	27,257,443	27,257,443	13,628,722	0	0
Interest PaId	13,250,146	12,960,601	12,647,893	12,310,167	11,945,424	11,551,501	11,126,065	10,666,593
TAXABLE EARNINGS	-28,305,678	-79,974,115	-49,276,310	-30,664,936	-30,142,813	-15,956,337	-1,731,643	-1,094,674
State Tax	-4,368,175	-5,278,292	-3,252,236	-2,023,886	-1,989,426	-1,053,118	-114,288	-72,248
Federal Tax	-8,378,126	-26,143,538	-16,108,426	-10,024,368	-9,853,686	-5,216,126	-566,074	-357,849
TOTAL TAX OBLIGATIONS	-12,746,301	-31,421,830	-19,360,662	-12,048,254	-11,843,111	-6,269,245	-680,363	-430,097

Description/Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES												
Energy Payments	19,917,405	20,576,472	21,257,347	21,960,753	22,687,434	23,438,161	24,213,730	25,014,962	25,842,708	26,697,843	26,697,843	27,581,274
Renewable Energy Certificates	0	0	0	0	0	0	0	0	0	0	0	0
Federal ITC and PTC	5,400,000	5,400,000										
TOTAL REVENUES	25,317,405	25,976,472	21,257,347	21,960,753	22,687,434	23,438,161	24,213,730	25,014,962	25,842,708	26,697,843	26,697,843	27,581,274
AVG $/KWH	0.084	0.087	0.071	0.073	0.076	0.078	0.081	0.083	0.086	0.089	0.089	0.092
OPERATING COSTS												
Scheduled and Unscheduled O&M	15,560,754	16,027,577	16,508,404	17,003,656	17,513,766	18,039,179	18,580,354	19,137,765	19,711,898	20,303,255	20,912,353	21,539,723
Scheduled O&R	0	0	53,844,090	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	15,560,754	16,027,577	70,352,494	17,003,656	17,513,766	18,039,179	18,580,354	19,137,765	19,711,898	20,303,255	20,912,353	21,539,723
EBITDA	9,756,651	9,948,895	-49,095,147	4,957,096	5,173,668	5,398,982	5,633,376	5,877,197	6,130,810	6,394,588	5,785,490	6,041,551
Tax Depreciation	0	0	0	0	0	0	0	0	0	0	0	0
Interest PaId	10,170,364	9,634,437	9,055,635	8,430,529	7,755,415	7,026,291	6,238,838	5,388,388	4,469,903	3,477,938	2,406,617	1,249,589
TAXABLE EARNINGS	-413,714	314,458	-58,150,782	-3,473,433	-2,581,747	-1,627,309	-605,462	488,809	1,660,907	2,916,649	3,378,873	4,791,962
State Tax	-27,305	20,754	-3,837,952	-229,247	-170,395	-107,402	-39,961	32,261	109,620	192,499	223,006	316,269
Federal Tax	-135,243	102,796	-19,009,491	-1,135,465	-843,973	-531,967	-197,926	159,792	542,950	953,453	1,104,554	1,566,492
TOTAL TAX OBLIGATIONS	-162,548	123,551	-22,847,442	-1,364,712	-1,014,368	-639,370	-237,886	192,053	652,570	1,145,952	1,327,559	1,882,762

CASH FLOW STATEMENT

Description/Year	2006	2007	2008	2009	2010	2011
EBITDA			32,266,418	8,701,607	8,800,655	8,902,674
Taxes Paid			-12,746,301	-31,421,830	-19,360,662	-12,048,254
CASH FLOW FROM OPS			45,012,719	40,123,436	28,161,317	20,950,928
Debt Service			-16,869,458	-16,869,458	-16,869,458	-16,869,458
NET CASH FLOW AFTER TAX		-70,982,926	28,143,261	23,253,978	11,291,859	4,081,470
CUM NET CASH FLOW		-70,982,926	-42,839,664	-19,585,686	-8,293,827	-4,212,357
IRR ON NET CASH FLOW AFTER TAX						

Description/Year	2012	2013	2014	2015	2016	2017	2018	2019
EBITDA	9,060,054	9,223,887	9,394,421	9,571,919	9,756,651	9,948,895	-49,095,147	4,957,096
Taxes Paid	-11,843,111	-6,269,245	-680,363	-430,097	-162,548	123,551	-22,847,442	-1,364,712
CASH FLOW FROM OPS	20,903,166	15,493,131	10,074,784	10,002,017	9,919,199	9,825,344	-26,247,705	6,321,808
Debt Service	-16,869,458	-16,869,458	-16,869,458	-16,869,458	-16,869,458	-16,869,458	-16,869,458	-16,869,458
NET CASH FLOW AFTER TAX	4,033,708	-1,376,327	-6,794,674	-6,867,441	-6,950,259	-7,044,114	-43,117,163	-10,547,650
CUM NET CASH FLOW	-178,650	-1,554,977	-8,349,651	-15,217,092	-22,167,351	-29,211,465	-72,328,628	-82,876,278

Description/Year	2020	2021	2022	2023	2024	2025	2026	2027
EBITDA	5,173,668	5,398,982	5,633,376	5,877,197	6,130,810	6,394,588	5,785,490	6,041,551
Taxes Paid	-1,014,368	-639,370	-237,886	192,053	652,570	1,145,952	1,327,559	1,882,762
CASH FLOW FROM OPS	6,188,036	6,038,352	5,871,262	5,685,144	5,478,239	5,248,636	4,457,931	4,158,789
Debt Service	-16,869,458	-16,869,458	-16,869,458	-16,869,458	-16,869,458	-16,869,458	-16,869,458	-16,869,458
NET CASH FLOW AFTER TAX	-10,681,422	-10,831,106	-10,998,196	-11,184,314	-11,391,219	-11,620,822	-12,411,527	-12,710,669
CUM NET CASH FLOW	-93,557,700	-104,388,806	-115,387,002	-126,571,316	-137,962,535	-149,583,357	-161,994,884	-174,705,553
IRR ON NET CASH FLOW AFTER TAX								#DIV/0!