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

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1 Introduction and Summary

This document describes the results of a 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 Hawaii. For purposes of this point design study, the Hawaii stakeholders selected the Ocean Power Delivery (OPD) Pelamis wave energy conversion (WEC) device, Honolulu for assembly of the device, grid connection at the Waimanalo Beach substation and a deployment site of Makapuu Point approximately 2.5km north of Makai Pier at a water depth of 50 meters on Oahu's southeast (windward) shore. 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).

There is a current offshore wave energy project in Hawaii. An Ocean Power Technologies, Inc. (OPT) 20 kW PowerBuoy™ unit was installed in the summer of 2004 near Kaneohe Bay in the State of Hawaii. This deployment is part of the first phase of the OPT's contract from the US Navy, for potential installation of a 1 Megawatt wave power station off Marine Corps Base Hawaii at Kaneohe Bay on the island of Oahu. Construction of the PowerBuoy system was performed primarily by Hawaiian fabricators. The deployment was supported entirely by local diver and workboat subcontractors. This included tow-out of the PowerBuoy to the deployment site, and the connection of the system to the anchor located on the sea bottom. According to Don Rochon[1] of the Naval Facilities Engineering Command, "OPT and the Navy have a shared commitment to this program for the operation of OPT's wave power systems in Hawaii." The PowerBuoy is located approximately one km off the coast, in 30 meters of water, and is initially rated for production of 50 kilowatts of electrical power. The buoy is less than 5 meters in diameter and 15 meters long.

In this study, a pilot scale wave power plant at Makapuu Point, Oahu, Hawaii, using a single Pelamis Wave Energy Conversion device rated at 750 kW was evaluated. The yearly electrical energy produced and delivered to the grid is estimated to be 1,003 MWh at the selected deployment site and would cost $4.5 million to build ($4.1 million after 10% Federal Investment 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 Detailed Design, Permitting and Construction Financing, Yearly O&M nor Test and Evaluation

A commercial scale wave power plant at Makapuu Point was also evaluated to establish a base case from cost comparisons to other renewable energy systems. The yearly electrical energy produced and delivered to bus bar is estimated to be 1,663 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

[1] OPT News Release, June 2004

devices are required. This is the equivalent output of a commercial 90MW wind farm operating at a capacity factor of 38%. The elements of cost and economics (with cost in 2004$) are:

- Utility Generator Total Plant Investment = $270 million (includes $28 million transmission upgrade to be paid back to project with interest)
- Annual O&M Cost = $12 million; 10-year Refit Cost = $26 million
- Levelized Cost of Electricity (COE)[2] = 10.4 (Real) - 12.4 (Nominal) cents/kWh with Federal Production Credit (PTC)
- Internal Rate of Return (IRR) = 9.6% (based on avoided cost electricity sales price) with Federal PTC

Makapuu Point, Oahu, Hawaii has the potential of being a very good area for locating an offshore wave power plant. While manufacturing facilities are limited, there is excellent R&D infrastructure in place, which can be leveraged for a demonstration system on the Makai pier on the southeast (windward) shore of Oahu. The Hawaii commercial scale power plant design, performance and cost 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 and IRR.

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. There is 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 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?

[2] For the first 90 MW plant assuming a regulated utility generator owner, 20 year plant life, 10 years of Federal Production Tax Credit at 1.8 cents/kWh and other assumptions documented in Reference 3

- 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)?

- 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)?

- 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 recommendations to the Hawaii Electricity Stakeholders:

1. Monitor the OPT demonstration project in Hawaii and the OPD Pelamis demonstration project in Scotland and update the performance, reliability and cost projections as appropriate based on these tests.

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

   In order to accelerate the growth and development of an ocean energy industry in the United States and to address and answer the many techno-economic challenges, a technology roadmap is need which can most effectively be accomplished through leadership at the national level. The development of ocean energy technology and the deployment of this clean renewable energy technology would be greatly accelerated if the Federal Government were supporting the development. Appropriate roles for the Federal Government in ocean energy development could include some, or all, of the following:

   - Providing leadership for the development of an ocean energy RD&D program to fill known R&D gaps identified in this report, and to accelerate technology development and prototype system deployment
   - Operating a national offshore wave test center to test the performance and reliability of prototype ocean energy systems under real conditions
   - Development of design and testing standards for ocean energy devices
   - Joining the International Energy Agency Ocean Energy Systems Implementing Agreement to collaborate RD&D activities, and appropriate ocean energy policies with other governments and organizations
   - Leading activities to streamline the process for licensing, leasing, and permitting renewable energy facilities in U.S. waters
   - Studying provision of production tax credits, renewable energy credits, and other incentives to spur private investment in ocean energy technologies and projects, and implementing appropriate incentives to accelerate ocean energy deployment
   - Ensuring that the public receives a fair return from the use of ocean resources
   - Ensuring that development rights are allocated through a transparent process that takes into account state, local, and public concerns.

3. Encourage R&D at universities such as University of Hawaii

4. Seek funding for a pilot feasibility demonstration plant at Makapuu Point, Hawaii.

   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.

2 Site Selection

Based on information provided by EPRI, the Hawaii state stakeholders selected Makapuu Point on the island of Oahu as an area for locating an offshore wave power plant. Fabrication and assembly would be performed in Honolulu harbor, and the grid interconnection would be at the Waimanalo beach substation.

The Makai research pier is located on the southeast (windward) shore, which is used for R&D purposes. The research pier can be used as an easement to land the power to shore, eliminating many issues associated to crossing the shoreline. The cable could be laid right up to the pier and then laid over the pier to the 12.5kV voltage line, which runs along the coast within a distance of a couple of hundred yards of the research pier. It might even be possible to interconnect on the pier itself for the purpose of a single unit demonstration. Either way, the available capacity allows for a gradual build out, using existing grid infrastructure. The following illustration shows the Hawaiian island and the Humpback Whale National Marine Sanctuary. The deployment site is located on the southeast (windward) shore of Oahu, at Makapuu point.

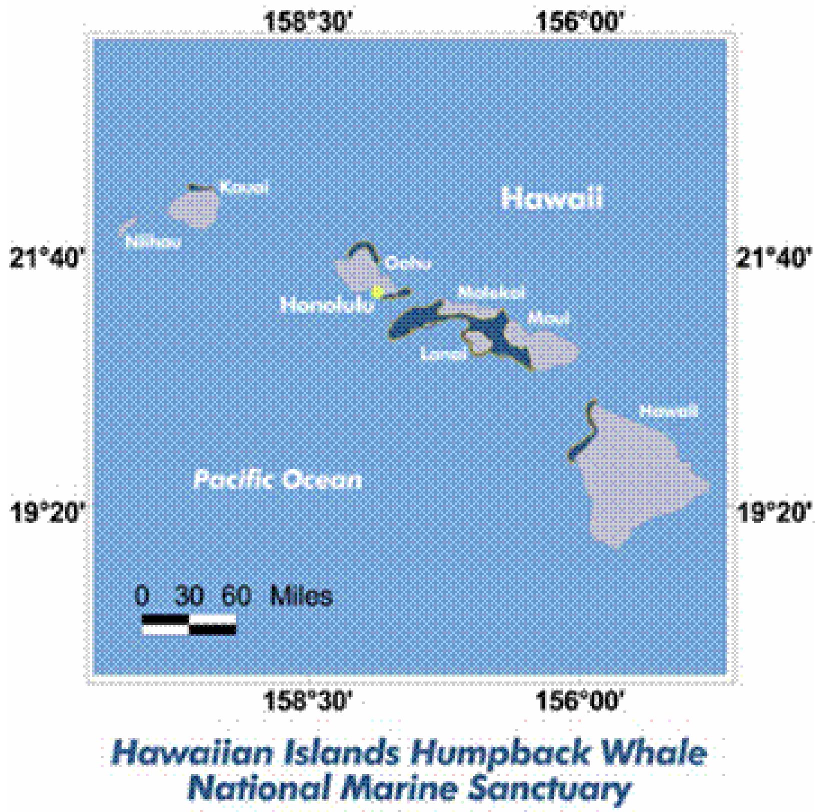


Figure 1: The Hawaiian Islands Marine Sanctuaries (marine sanctuary shown in dark blue)

The Figure 2 local site map shows the deployment site (#3) in close proximity to Monana island, the Makai research pier (#2) used to land the power cable to shore and the substation at Waimanalo beach (#1). The Makapuu Point measurement buoy (4) is located just a little bit further to the east. For the demonstration plant, it is possible to interconnect in close proximity to the research pier to a 12kV distribution line, which runs along the southeast (windward) shore and interconnects at Waimanalo beach substation.

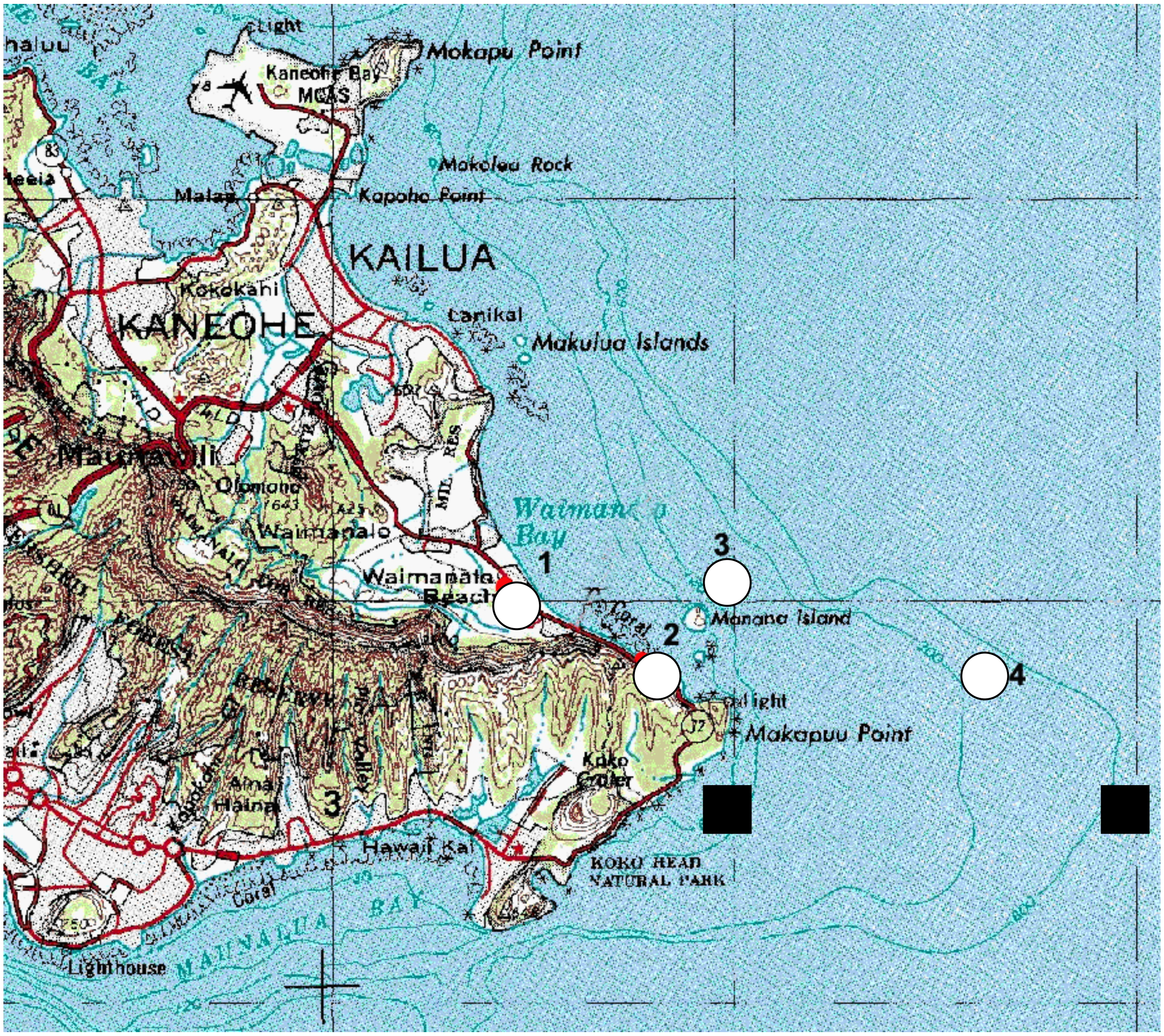


Figure 2: Local Site Map

Aerial views of the deployment site and the Makai Research Pier are shown in Figures 3 and 4, respectively. The local bathymetry map is shown in Figure 5 with ocean depth in fathoms (1 fathom = 6 feet). The deployment site is at a depth of 50 meters.

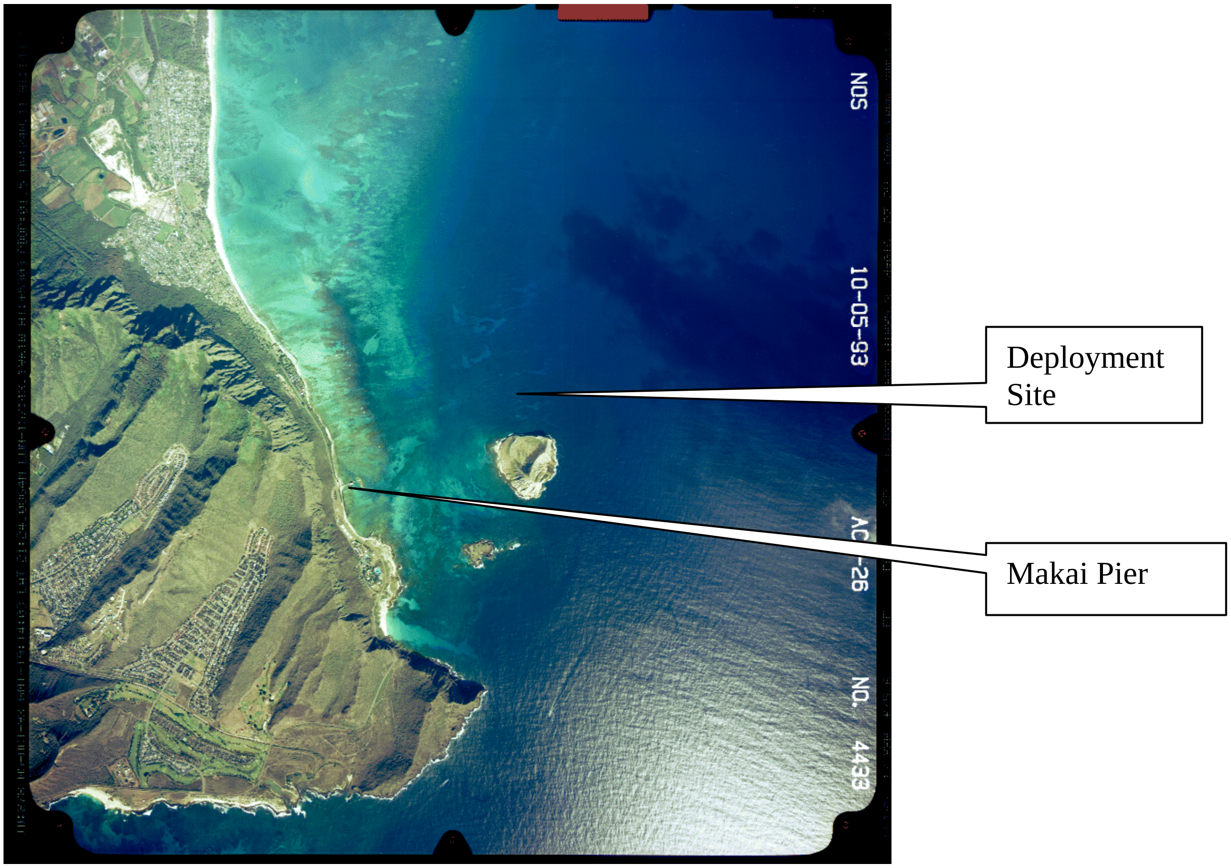


Figure 3: Aerial picture of the deployment site

Figure 4: Makai Research Pier used to land power cable

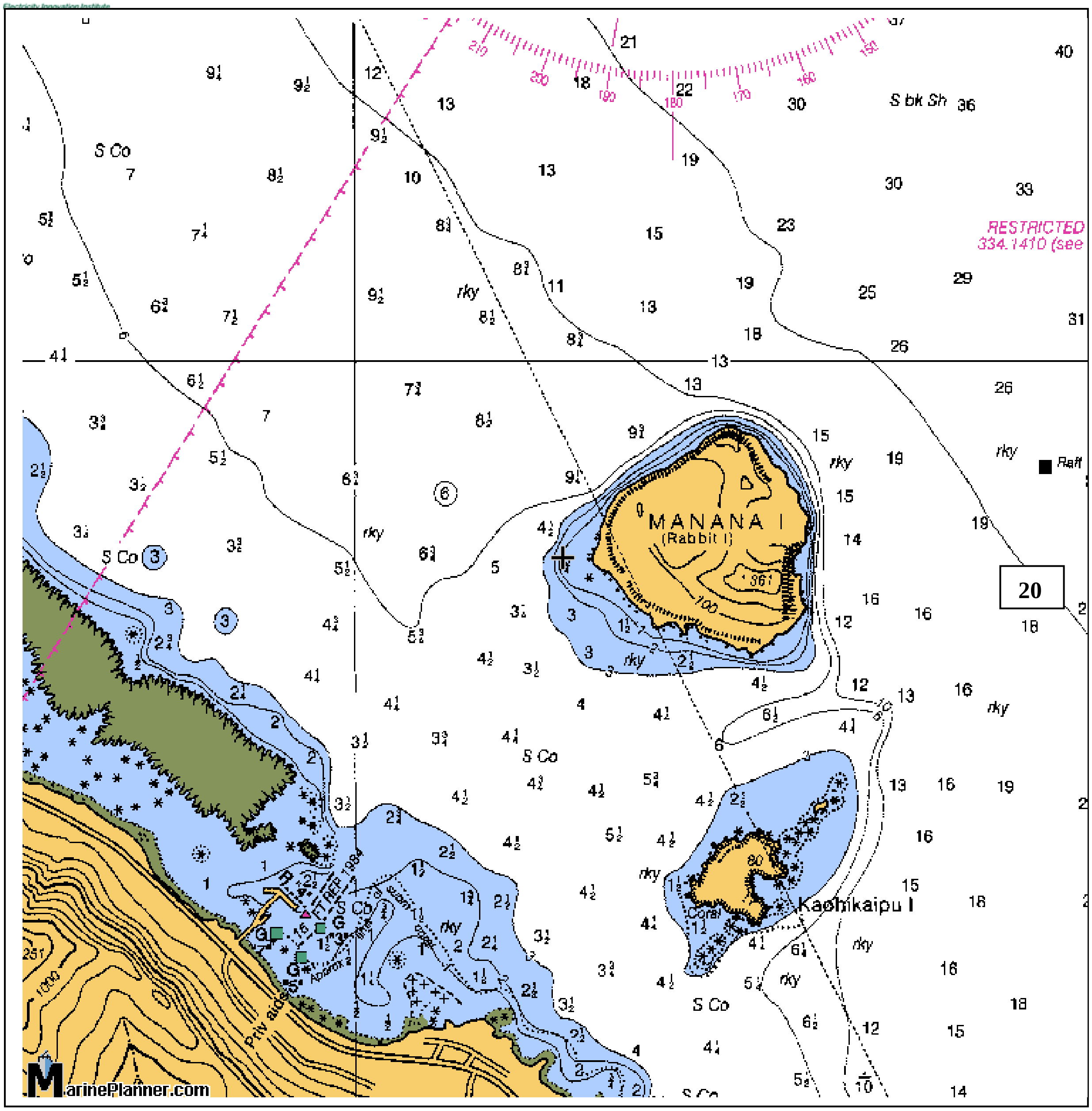


Figure 5: Local Bathimetry map showing the water depth in fathoms (1 fathom = 6 feet)

Based on discussions with a local ocean engineering firm[3], the ocean floor is mostly limestone. There are also no indications that sand channels exist which could be used to burry a power cable. The current Pelamis mooring design will need to be adapted in order to accommodate the hard ocean floor. 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.

The deployment site close to Makapuu Point has the following relevant site parameters which are used in later sections for site design and costing purposes.

Water Depth at Deployment Site	50m
Distance from pier to 12kV line	500m
Sub-sea Cable Length	2km
Total Cable Length Required	2.5km
Overland Transmission Substation-Cable landing Site	5km
Ocean Floor Sediments	Bedrock / Limestone
Transit Distance to Honolulu for O&M[4]	40 km

[3] Personal communication, Robert Rocheleau, SeaEngineering

[4] The 40 km transit distance is from the deployment site north of Manana Island to inside Sand Island in Honolulu harbor

3. Wave Energy Resource Data

In order to characterize the wave resource at the proposed site, the Makapuu Point CDIP 034 wave measurement buoy was chosen to obtain wave data from. Below are some key results of the reference measurement station and characterization of the wave climate. The measurement buoy is in close proximity to the proposed deployment site. As a result, the measurements are very representative of the wave climate that the wave power units will experience. Figure 6 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 034
Station Name:	Makapuu Point
Water depth:	100m
Coordinates:	21° 24.9’ N 157° 40.7’ W
Data availability:	21 years (1981 – 1996 and 2000 - 2004)
Maximum Significant Wave Height (Hs):	6.3m
Maximum Singinficant Wave Period (Tp):	25.6 s
Estimated Single Wave Extreme Event:	13m
Average Annual Power Flux	15.2 kW/m

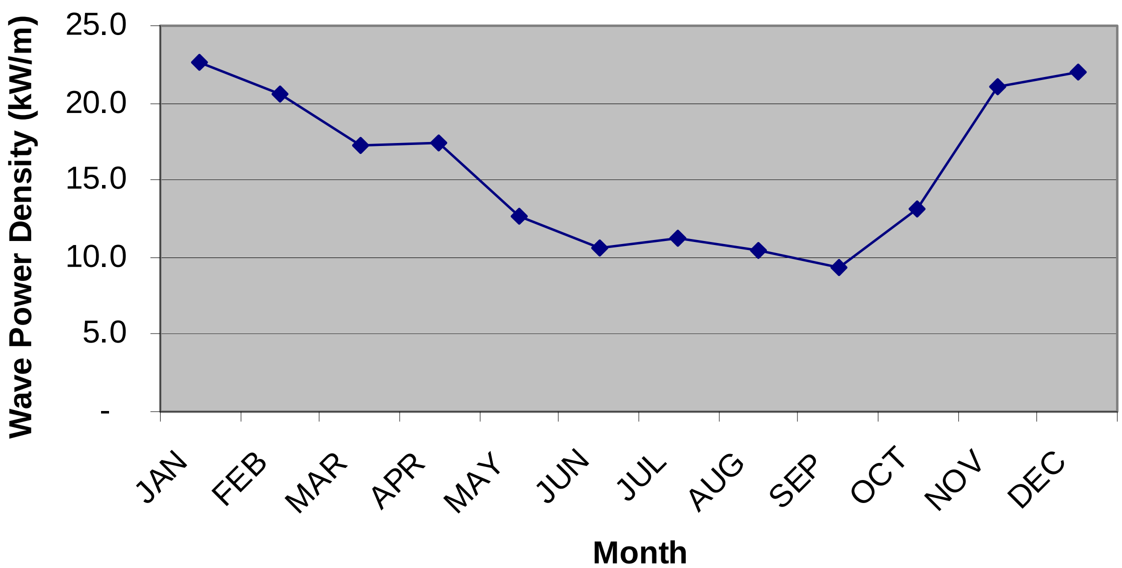


Figure 6: Monthly Average Wave Power Flux (kW/m)

4. The Technologies

The WEC device chosen for the Hawaii 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 7 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 8.

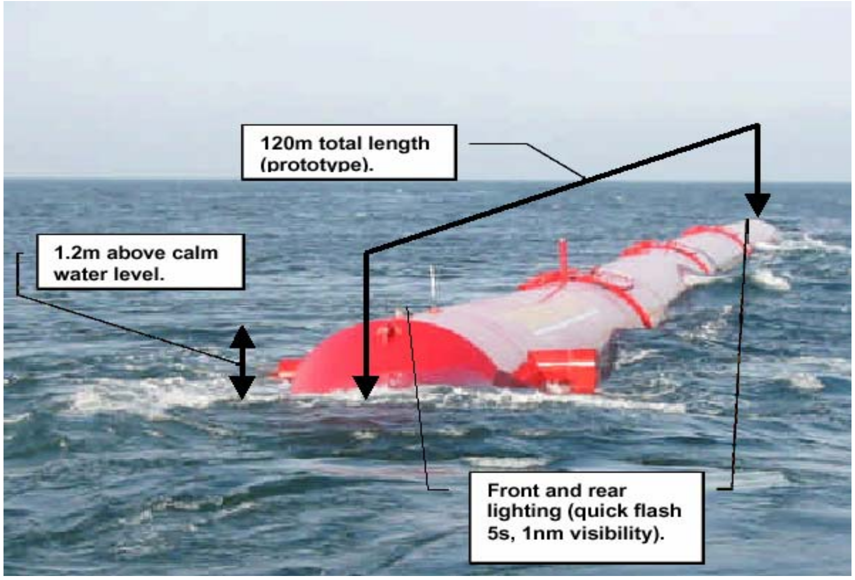


Figure 7: Pelamis pre-production prototype undergoing sea-trials

Figure 8: 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.

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

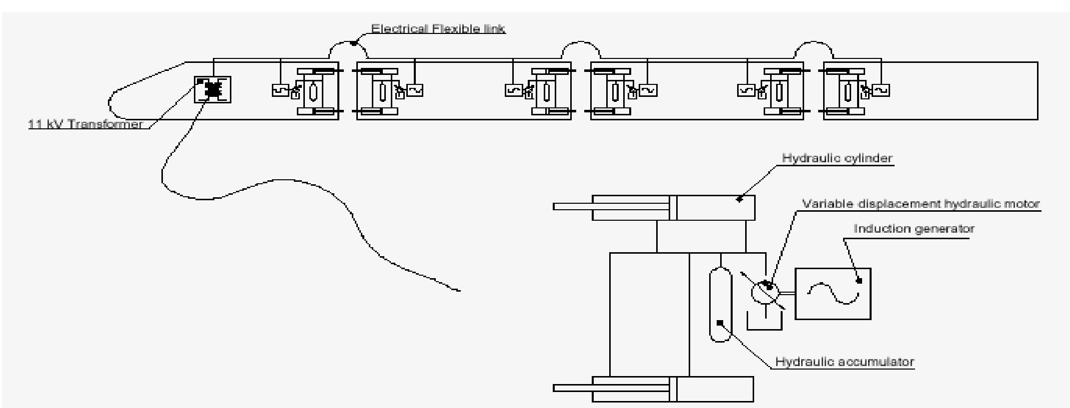


Figure 9: Pelamis Power Conversion Train

The Power Conversion Module (PCM)

As illustrated in Figure 9, a total of 3 power conversion modules (PCM's) connect the 4 individual steel tubes forming a Pelamis device. Each PCM 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.

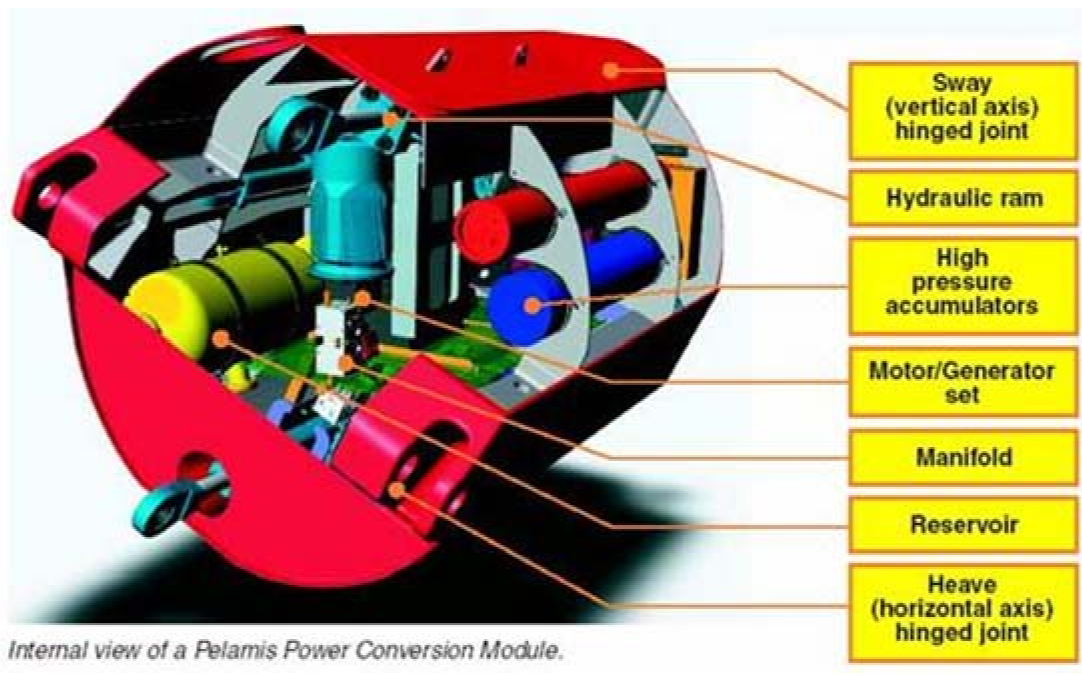


Figure 10: Internal View of the Pelamis PCM

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 11: 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 12. This is an existing design for a sandy bottom. A mooring design for a rocky bottom does not currently exist. As discussed in the cost estimate sections, we increased the cost estimate of the existing sandy bottom design to account for a more difficult mooring in a Hawaii environment.

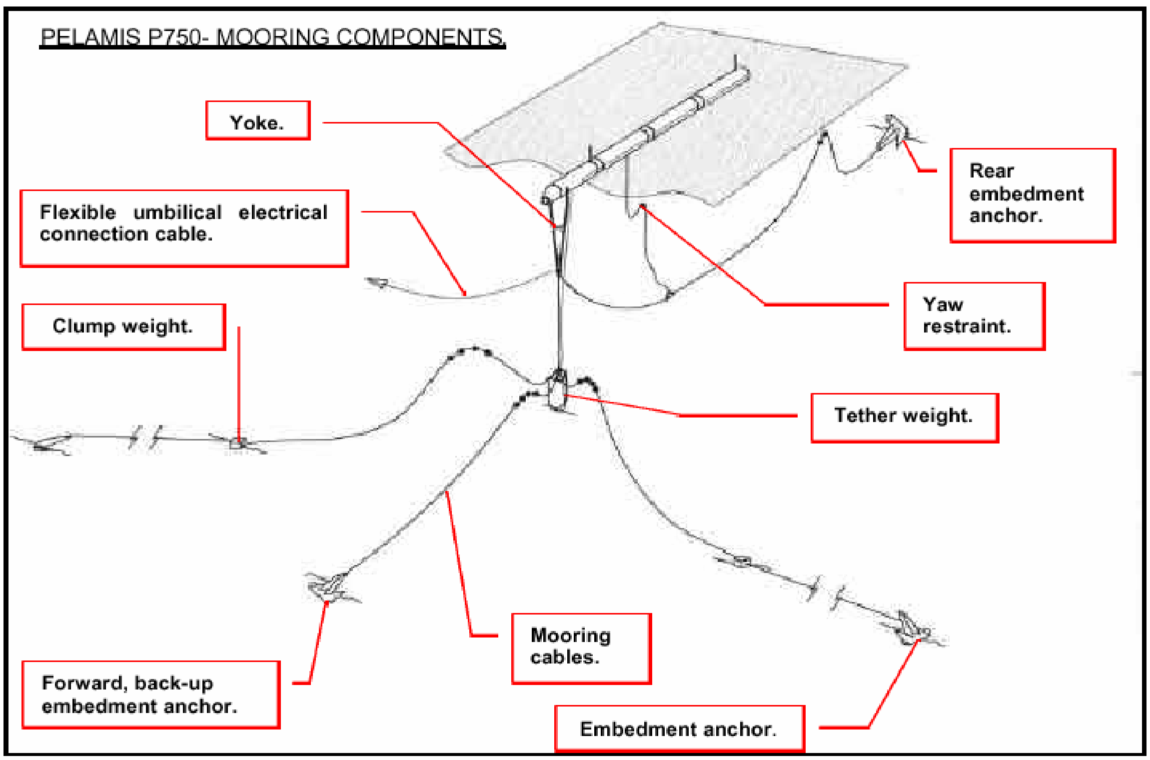


Figure 12: Mooring Arrangement of Pelamis

As shown in Figure 12, the Pelamis mooring system is a catenary type mooring using a combination of steel wire, chain, dead weights and embedment anchors. The following four pictures of Figure 13 show some of the individual mooring elements to provide the reader with an understanding of the size of these individual components.

Embedment anchor.

Clump weight.

Mooring cable.

Figure 13: Mooring Illustrations

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 case primary communication fails.

Subsea Cabling

Umbilical cables to connect offshore wave farms to shore are 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. Traditionally, sub-sea cables have been oil-insulated, however, recent offshore wind projects in Europe show that environmental risks prohibit the use of such cables in the coastal environment. XLPE insulations have proven to be an excellent alternative, having no such potential hazards associated with its operation. Figure 14 shows the cross-section of armored XLPE insulated submersible cables.

Figure 14: 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 wherever possible to drive down costs and avoid permitting issues. 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 plant, the 3 PCMs are procured from Ocean Power Delivery (OPD) and are shipped from the UK to Honolulu. The structural steel sections are built locally in an appropriate shipyard. Manufacturing facilities capable of constructing the larger steel sections do exist near Honolulu. Alternatively, the steel sections could be manufactured on the US mainland and shipped to Oahu. Figure 15 shows the Pelamis prototype under construction in Scotland. The picture on the left shows a hydraulic ram being mounted in one of the PCMs. The picture on the right shows the large tubular steel sections of the Pelamis being completed.


Figure 15: 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 PCM's. This will allow for a large amount of US content in the devices and bring benefits to the local economy. Honolulu has adequate infrastructure in place to carry out annual overhauls and 10-year refits, which will be required to replace major subsystems.

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 OPD who deployed a prototype device this year, local Sea Engineering who managed the installation of OPT Power Buoy in Hawaii. The major installation activities for both demonstration plant and commercial wave farm are:

1. Install cable landing 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 16 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 a AHATS class vessel in the project cost and hire dedicated staff to carry out operational activities. Figure 17 shows the prototype Pelamis being towed to its first deployment site off the coast of Scotland.

Figure 16: 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.

Figure 17: 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 18) 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 laid on the ocean floor, protected by steel pipes and secured by rock-bolts to the sea-bed. The cable landing site for the demonstration site is at the Makai Research Pier. This research pier is located roughly 500m from a 12kV distribution line, which can be used to feed power into the grid.

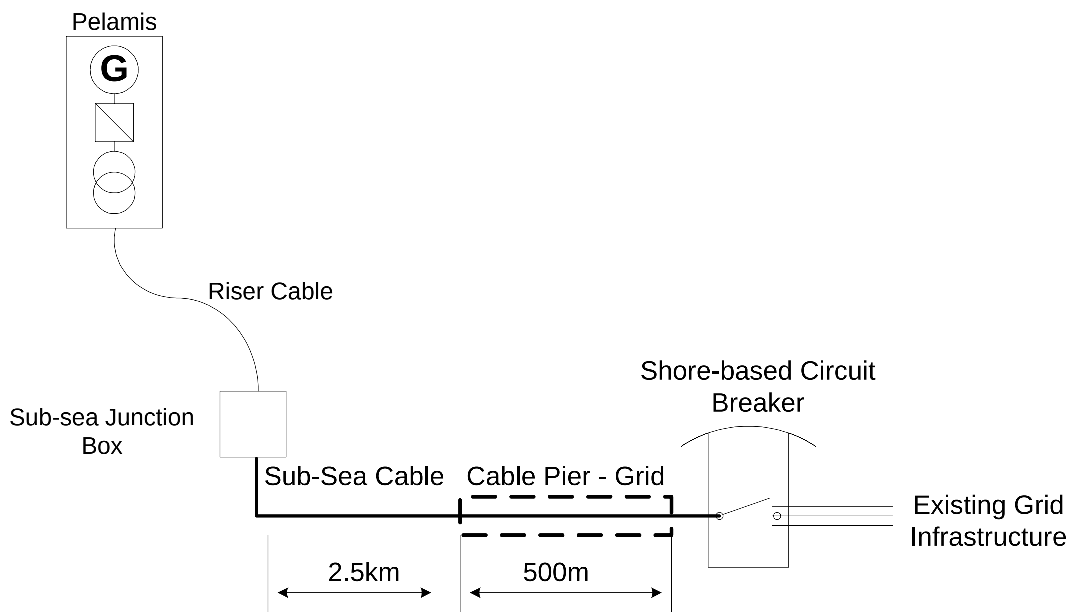


Figure 18: Electrical Interconnection of a 1 Pelamis Pilot Plant

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 in this particular location.

The existing pier infrastructure will allow a low cost introduction and gradual build-out of capacity. It is expected that at a certain point, additional cables will need to be landed to shore in order to accommodate additional load of a larger commercial wave farm. This approach will allow 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. Being an island, Hawaii offers unique opportunities such as the fact that the cost of electricity is higher then on the mainland. However, it also does present unique challenges such as being far away from manufacturing facilities and having higher cost of doing business.

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 19, the commercial system uses a total of 4 clusters, each one containing 45 Pelamis units (180 Pelamis WEC devices), connected to sub-sea cables. The sizing was based on the number of Pelamis devices needed to provide an annual electrical output, at the busbar, of 300,000 MWh/yr (the equivalent of a 100 MW wind power farm with a capacity factor of 40%). The sizing result was that 180 Pelamis devices, each device rated at 500 kW (see Section 9, Table 7, Note 4 for an explanation of derating the commercial plant Pelamis units from the 750- kW demonstration unit), was needed, thus having a total plant rating of 90 MW and a capacity factor of 38%. 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 19. 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
System Voltage	26kV
Sub-sea cable specs	26kV / 40MVA / 3-phase with fiber optic core

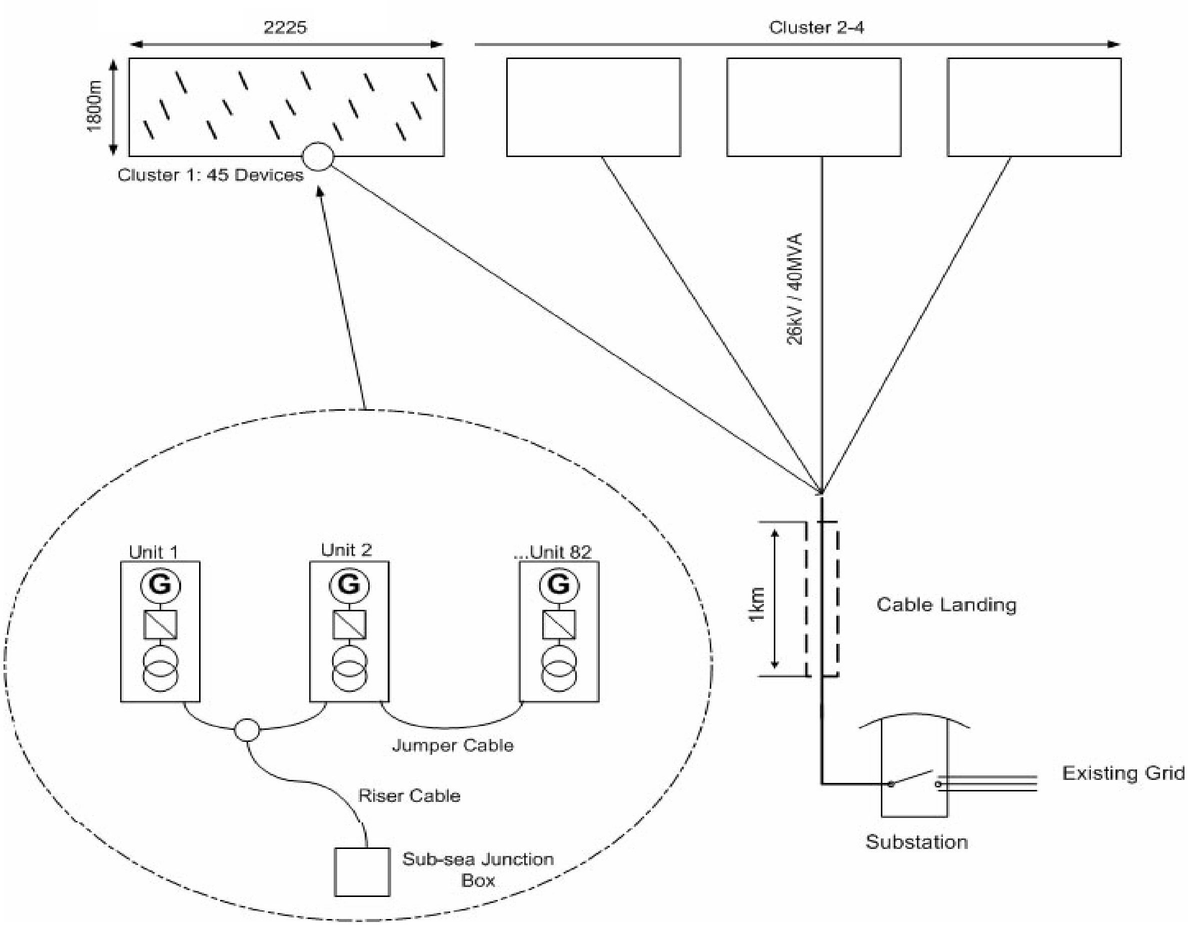


Figure 19: Overall System Layout and Electrical Connections

Wave farm voltage should be kept below 35kV as higher voltage levels will increase cabling and interconnection costs. The 90MW commercial scale plant design uses four 26kV/40MVA cables connecting the 4 clusters back to shore. The voltage level can be adjusted by changing the windings of the step-up generator (located in the Pelamis nose) to yield the proper levels. Stepping up voltage levels further is only required if the wave farm is going very far offshore

(100 km plus). Because deep water (60 meters or so) sites in Hawaii are within 5miles of the coast, there is no need for stepping up the voltage.

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 its 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 Honolulu, 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 Honolulu, budget allowance was given to accommodate improvement to streamline such operational tasks.

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 southeast (windward) shore of Oahu.

Transmission line losses for the sub-sea cable from the offshore farm to the grid interconnection point at Waimanalo beach 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 20 shows the average power (kW) delivered to the grid by a single Demonstration Pilot Plant Pelamis 750kW WEC Device sited as described in Section 2.

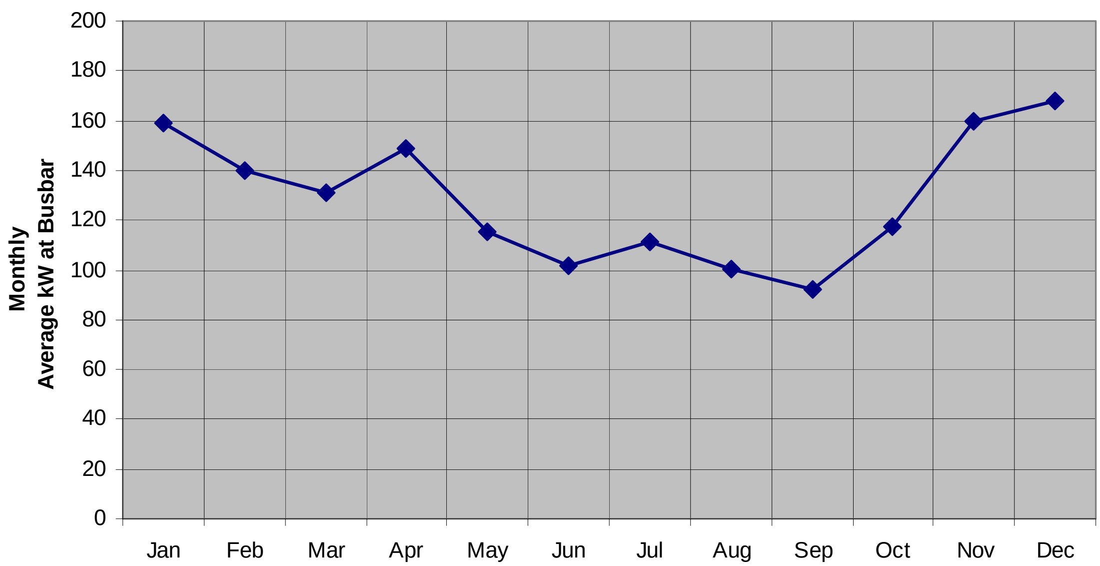


Figure 20: Monthly average power delivered to bus bar – Pilot Plant

A scatter diagram of the annual and monthly wave energy available at the Oahu North Shore site was developed using long-term statistics from the Makapuu Point CDIP 034 wave measurement buoy. The scatter diagram for the annual energy is shown in Table 2.

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

CDIP 0034 Makapuu Point																				
		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	Total hours
		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	
Hs and Tp bin boundaries			Tp (sec)																	
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	
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	1	2	0	1	1	1	1	0	0	0	0	8
4.25	4.75	4.5	0	0	0	0	0	0	4	3	1	1	3	1	1	1	0	0	0	15
3.75	4.25	4	0	0	0	0	0	2	10	6	4	4	7	4	0	1	0	0	0	38
3.25	3.75	3.5	0	0	0	0	2	9	32	21	15	17	15	8	0	4	0	0	0	121
2.75	3.25	3	0	0	0	0	17	48	93	45	36	37	45	22	1	3	0	0	0	349
2.25	2.75	2.5	0	0	0	38	115	220	267	85	84	103	102	48	4	8	2	0	0	1,077
1.75	2.25	2	0	0	15	292	353	589	558	164	210	282	245	106	11	27	3	2	0	2,857
1.25	1.75	1.5	0	1	151	412	376	641	520	217	270	325	306	154	12	42	1	2	1	3,432
0.75	1.25	1	0	2	29	51	68	168	169	73	82	91	78	38	3	9	2	1	0	864
0.25	0.75	0.5	0	0	0	0	1	1	2	0	1	0	0	0	0	0	0	0	0	5
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		8,766	0	3	195	793	932	1,678	1,655	616	703	862	802	382	34	96	9	6	1	8,766

Table 3: Pelamis Wave Energy Conversion Absorption Performance (kW) in each sea-state (Excluding Power Take Off losses) – Pilot Plant

	Tp (s)																
Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20
10	750	750	750	750	750	750	750	750	750	750	750	750	711	750	750	738	734
9.5	750	750	750	750	750	750	750	750	750	750	750	750	691	750	710	694	662
9	750	750	750	750	750	750	750	750	750	750	750	750	670	746	668	650	592
8.5	750	750	750	750	750	750	750	750	750	750	750	750	650	699	626	606	551
8	750	750	750	750	750	750	750	750	750	750	750	750	630	653	584	562	509
7.5	750	750	750	750	750	750	750	750	750	750	750	748	610	607	542	518	467
7	750	750	750	750	750	750	750	750	750	750	750	692	566	560	500	474	425
6.5	750	750	750	750	750	750	750	750	750	750	723	592	617	513	458	430	384
6	597	630	663	684	750	750	750	750	750	750	616	633	525	476	396	386	329
5.5	428	497	566	612	750	750	750	750	750	635	642	532	482	400	399	341	322
5	259	364	469	539	750	750	750	750	644	641	531	482	399	394	330	308	274
4.5	94	233	371	467	735	744	738	634	626	520	473	390	382	319	299	250	208
4	105	216	326	394	632	616	583	585	494	454	374	361	339	283	236	197	153
3.5	0	86	211	326	484	577	568	502	421	394	330	312	260	216	196	164	140
3	0	91	180	246	402	424	417	369	343	331	275	229	208	173	144	120	93
2.5	0	7	93	171	279	342	351	320	274	230	210	174	145	120	100	84	65
2	0	0	66	109	199	219	225	205	195	162	135	112	93	77	64	54	41
1.5	0	0	26	62	112	141	143	129	110	91	76	63	52	43	36	30	23
1	0	0	11	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 in the hours of reoccurrence scatter diagram (Table 2) by each corresponding cell in the single Demonstration Pilot Plant Pelamis 750kW WEC Device performance scatter diagram (Table 3), the total energy in each sea state was calculated. By summing up the cells in the conjoined table, the annual output (MWh/year) per Pelamis WEC device was derived. Pilot plant performance numbers are summarized below.

Table 4: Pilot Plant Pelamis Performance

Device Rated Capacity	750kW
Annual Energy Absorbed	1,452 MWh/year
Device Availability	85%
Power Conversion Efficiency	80%
Annual Generation at bus bar	1,003 MWh/year
Average Power Output at bus bar	113 kW
Capacity Factor	15%

The commercial plant performance was assessed using the demonstration plant 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 fraction of its theoretical limit. An increase in performance by a factor of 2-3 is possible without significant changes to the device geometry[5]. For purposes of this study, only performance improvements were considered which could be achieved in the near future, without any additional research. The only changes incorporated in the commercial Pelamis performance numbers are:

- Changing the mooring configuration will yield a performance improvement of 37%.[6]
- The current PCMs use standard off the shelf components. Customization would increase the power conversion efficiency by more then 10%. The technology exist and is therefore included in the performance for the commercial plant.
- The rated capacity was changed to 500kW, because the 750kW design is overrated for the Hawaii 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.

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

Table 5: Commercial Plant Pelamis Performance

Device Rated Capacity	500kW
Annual Energy Absorbed	1,989 MWh/year
Device Availability	95%
Power Conversion Efficiency	88%
Annual Generation at bus bar	1,663 MWh/year
Average Electrical Power at bus bar	191 kW
# Pelamis required to meet target 300,000 MWh/yr	180
Capacity Factor	38%

[5] Personal communication with OPD staff and agreed to by the E2I EPRI Global Project Team

[6] The configuration has been evaluated in wave tank tests and theoretical studies by OPD and is well quantified.

8. Cost Assessment – Demonstration 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 Ocean Power Delivery, 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 – Single 750 kW Pelamis

Cost Element	Pilot Plant	Basis
Onshore Transmission & Grid Interconnection	$194,000	(1)
Subsea Cables	$546,000	(2)
Pelamis Power Conversion Modules	$1,622,000	(3)
Pelamis Manufactured Steel Sections	$850,5000	(4)
Pelamis Mooring	$275,500	(5)
Installation	$633,000	(6)
Construction Mgmt and Commissioning (10% of cost)	$409,000	(7)
Total	**$4,530,000**	
Federal Tax Incentive (10%)	**$453,000**	
Total	**$4,077,000**	

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 Honolulu Hawaii 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 and increased by 20% to account for the more difficult rocky bottom of Hawaii as compared top the sandy bottom design and installation experience of OPD. 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. Where required, some adjustments have been made to adjust for local cost. However, generation costs proved to be insensitive to local cost drivers such as labor and land lease cost. If 100% was locally manufactured, this would change, as manufacturing in Hawaii will be more costly. Traditionally, Hawaii is not a manufacturing location and large items will likely be shipped in from the mainland and assembled locally.

   - Local vessel day rates for offshore operation of a tug plus barge have been used for demonstration unit deployment

   - Steel manufacturing costs have been kept the same as on the U.S. mainland and it is unclear if it will be economically competitive to manufacture such a structure locally as Hawaii is clearly not a low cost manufacturing location. Alternative options would include shipping large steel sections from the U.S. mainland or Korea/China. Shipping from the mainland would likely increase costs slightly (by 10% - 20%), while shipping from Korea/China would likely decrease costs because of the lower construction costs, not considering import taxation on manufactured products. In either case, this is by far the largest item and is covered within our range of cost uncertainty.

   - For the commercial plant layout, the O&M cost was estimated using a bottoms-up model. Looking at the sensitivity, labor cost might increase slightly as compared to the mainland and was not accounted for. Labor cost accounts for about 12% of O&M costs. So once again, adjusting to local cost would yield insignificant changes and is covered by the estimated uncertainty cost band.

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

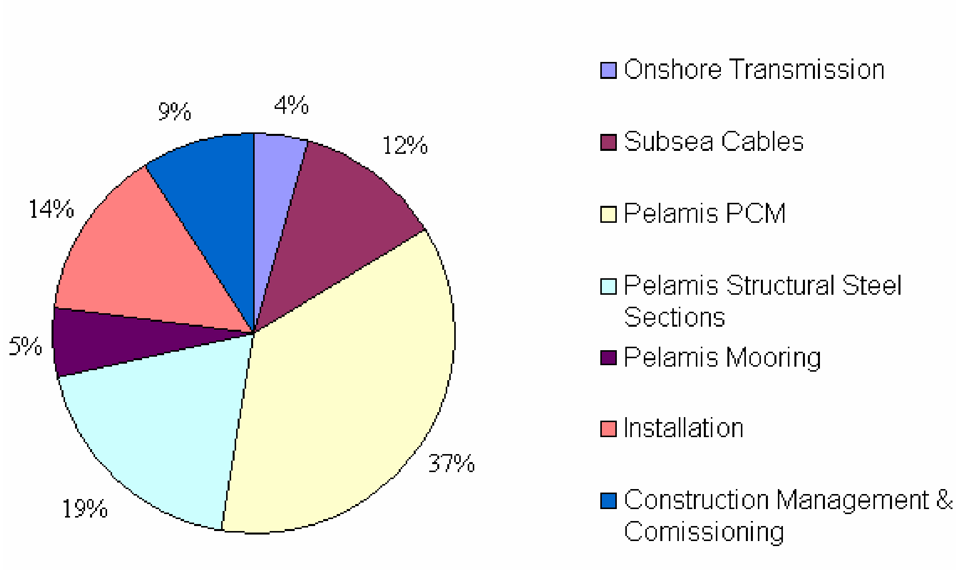


Figure 21: Pie Chart of cost centers for single unit installation

Cost uncertainties were estimated for each cost component and a Monte Carlo simulation was used to determine the likely capital uncertainty of the project. The uncertainty band for the mooring design wads increased from 30% for the OPD sandy bottom design to +50% and -30 % for both the demonstration and commercial plant designs. Figure 22 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 +22%. This bottom-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).

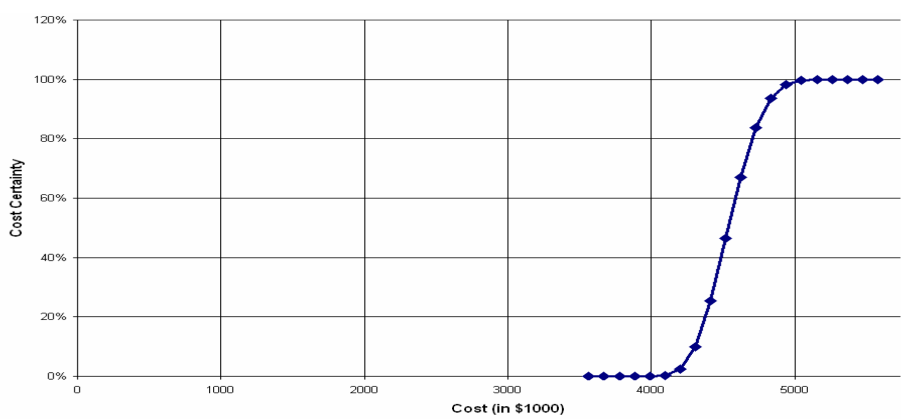


Figure 22: Cost Uncertainty based on Monte Carlo Simulation

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 90 MW 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 - Commercial Scale Plant – 180 Pelamis Units – 90MW

Cost Element	**180-Pelamis Device System**		**Basis**
Constant Dollar Year	2004	in %	
Installed Cost			
Onshore Transmission & Grid Interconnection	$27,084,000	11.%	(1)
Subsea Cables	$3,950,000	2 %	(2)
180 x Mooring Spread	$24,700,000	10 %	(3)
180 x Power Conversion Modules	$112,313,000	45 %	(4)
180 x Concrete Structural Sections	$44,064,000	18 %	(5)
Facilities	$12,000,000	5 %	(6)
Installation	$11,729,000	5 %	(7)
Construction Mgmt and Commissioning (5% of cost)	$11,206,000	4 %	(9)
Total Plant Cost	**$247,046,000**	**100%**	
Construction Financing Cost	$23,471,000		
Total Plant Investment	**$270,517,000**		
Yearly O&M			
Labor	$2,322,000	20 %	(10)
Parts (2%)	$4,941,000	40 %	(10)
Insurance (2%)	$4,941,000	40 %	(11)
Total	**$12,204,000**	**100%**	
10-year Refit			
Operation	$9,758,000	37 %	(10)
Parts	$16,804,000	63 %	(10)
Total	**$26,562,000**	**100%**	

(1) The onshore grid transmission and grid interconnection cost center includes a HECO cost estimate of $24 million in this cost element and $4 million in the installation cost element - see appendix E) for upgrading the overhead Waimanalo Beach to Koolau 138 kV line (8.4 miles long). As this cost will be paid back to the project with interest over the first 5 years after operation, this cost was kept in the capital cost estimates but not included in the economics analysis in Sections 10 and 12. Other costs are for cable landing directional drilling, popwer cable and substation circuit breakers

(2) Includes 14 km of subsea cable and steel protective pipe and a subsea termination box

(3) The mooring spread is an assembly of standard elements and equipment. A moderate cost reduction of 30% was assumed (as compared to the prototype – see section 7). This cost reduction can easily be achieved by purchasing in larger quantities.

(4) 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 500kW per device results in a relatively small decrease in annual output[7]. This is mainly attributed to the fact that the Hawaii site has a lower energy level 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 $289,000 for the power conversion train alone and another $234,000 for the manufactured steel enclosure, hinges and assembly for a total Pelamis unit cost (3 PCMs) of $523,000.

(5) 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.

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

(7) 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] Personal communication with OPD staff and agreed to by the E2I EPRI Global Project Team

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

(9) 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. 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 is required. 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. It will also need to be inspected at that point by ABS or a related agency.

(10) The failure rate of components and sub-systems are unknown at this time. The O&M cost element includes the cost of moving the WEC device to and from the dock for maintenance. 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.

(11) 2% is a typical insurance rate for offshore projects using mature technology.

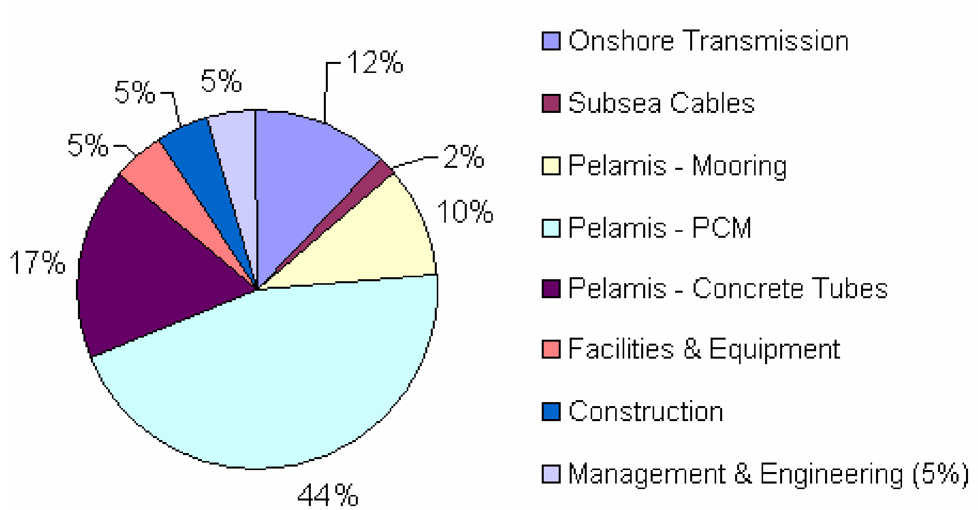


Figure 23: Installed Cost Breakdown for commercial scale plant

Cost uncertainties were estimated for each cost component and a Monte Carlo simulation was run to determine the likely capital uncertainty of the project. The uncertainty band for the mooring design wads increased from ± 30% for the OPD sandy bottom design to plus 50% and minus 30% for both the demonstration and commercial plant designs. Figure 24 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. These cost uncertainties were estimated for each cost center analyzed.

It shows that the cost accuracy is -23% 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.

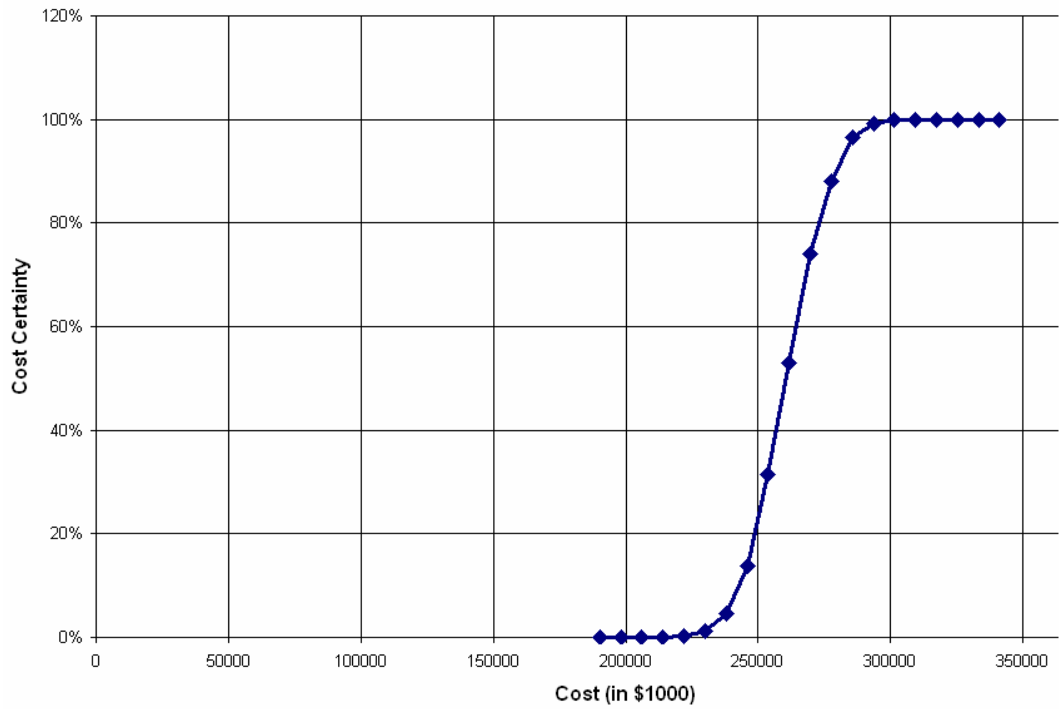


Figure 24: Installed Cost uncertainty S-curve

10. COE/IRR Assessment – Com'l Plant (90 MW – 38% Capacity Factor)

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. Spreadsheet solutions were created for both Utility and Non-Utility Generators and results are outlined in this section.

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 8: COE Assumptions for the State of Hawaii

	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 (Hawaii)	6.02%	6.02%
Composite Tax Rate	38.9%	38.9%
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%
Constant $ Discount Rate before Tax	9.25%	10.83%
Constant $ Discount Rate after Tax	5.77%	8.47%
Property Tax Rate	0	0
Insurance Rate (% of capital cost)	2	2
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	0	0
State Production Tax Credit	0	0
Depreciation	MACR Accelerated	MACR Accelerated
Avoided Cost (2002$)	N/A	8.41 cents/kWh[8]
Industrial Electricity Price Forecast (2002$) – The closest we could get to the electricity price as sold by a merchant plant to the grid operator	N/A	8% decline from 2002 to 2008, stable through 2011 and then a constant escalation rate of 0.3%

Utility Generator (UG)

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) using the methodology described in Reference 3. The details of this economic analysis are contained in Appendix B.

Table 9 Cost elements and their Impacts on COE for UGs (2008 initial operation – 20 year life - 2004 constant year $) – With and Without Federal PTC

Cost Element	Low	Best	High
Total Plant Investment	$182,319,000	$242,990,000	$333,649,000
Annual O&M Cost	$9,763,000	$12,204,000	$18,306,000
10-year Refit Cost (1 time cost)	$17,778,000	$26,562,000	$35,778,000
With Federal PTC			
Fixed Charge rate (Nominal)	9.0	9.7	9.9
Cost of Electricity (c/kWh) (Nominal)	**9.0**	**12.4**	**17.7**
Fixed Charge rate (Real)	6.7	7.2	7.3
Cost of Electricity (c/kWh) (Real)	**7.6**	**10.4**	**14.9**
Without Federal PTC			
Fixed Charge rate (Nominal)	11.1	11.2	12.31
Cost of Electricity (c/kWh) (Nominal)	**10.3**	**13.7**	**19.0**
Fixed Charge rate (Real)	8.2	8.4	8.2
Cost of Electricity (c/kWh) (Real)	**8.6**	**11.3**	**15.9**

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 because there is little experience with operating such wave farms which could be used to validate any of the numbers. 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

[8] The 4th quarter 2004 avoided energy cost (for over 100kW) on Oahu Hawaii was provided by HECO as 9.64 cents per kWh for on peak (7 am to 9 pm) and 7.37 cents per kWh for off-peak (9 pm to 7 am). The weighted daily average is therefore 8.69 cents per kWh (2004$). Adjusting for the EIA price model decline of 8% between 2002 and 2008 and for the 3% inflation gives a 2002$ value of 8.41 cents/kWh avoided cost

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.

Non Utility generator (NUG)

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.

Table 10: Cost elements and their impacts on IRR for NUGs (2008 initial operation – 20 year life – current year $ - Avoided Cost Electricity Selling Price)

Cost Element	Lowest Estimate	Best Estimate	High Estimate
Total Plant Investment (2004)	$183,386,000	$244,412,000	$335,601,000
Annual O&M Cost (2004$)	$9,763,000	$12,204,000	$18,306,000
10-year Refit Cost (2004$)	$17,778,000	$26,562,000	$35,778,000
Internal Rate of Return with PTC	35.3%	9.6%	No IRR
Internal Rate of Return without PTC	15.4%	No IRR	No IRR

Table 10 shows that the first commercial plant owned by a NUG provides a positive rate of return of 15.4 to 35.3 % for the lowest cost estimate case where the electricity sell price is the avoided cost of electricity in Hawaii and with and without Federal PTC. The best cost estimate provides a 9.6 IRR the case where there is a Federal PTC and no IRR with no Federal PTC. Figure 25 and 26 shows the cumulative cash flow and yearly net cash flow, respectively, in current year dollars for the 20 year life of the best estimate with PTC (9.6% IRR) Figure 27 and 28 shows the cumulative cash flow and yearly net cash flow, respectively, in current year dollars for the 20 year life of the best case estimate case without PTC.

Figure 25: Cum Cash Flow – Best Cost Estimate – With PTC

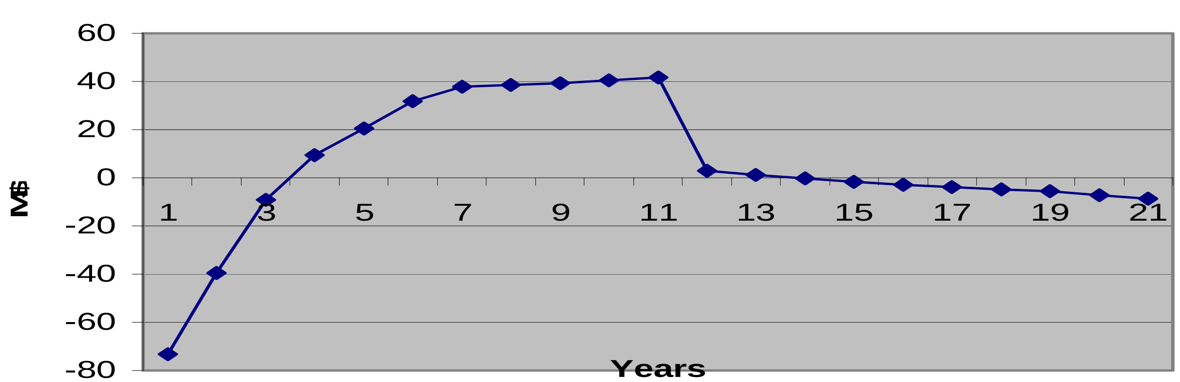


Figure 26: Net Cash Flow – Best Cost Estimate – With PTC

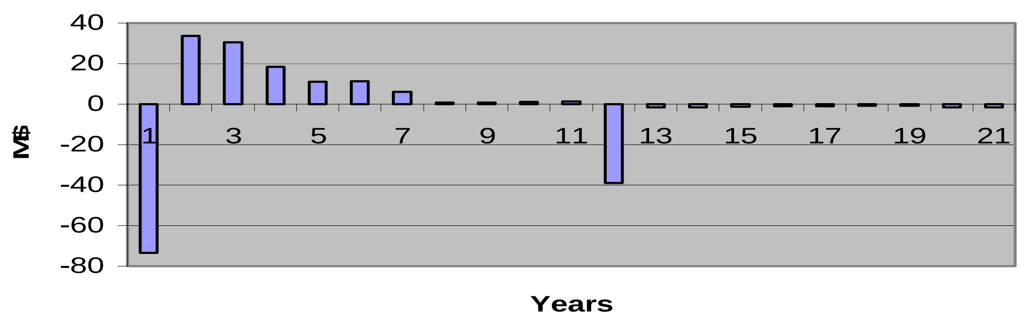


Figure 27: Cum Cash Flow – Best Cost Estimate – W/O PTC

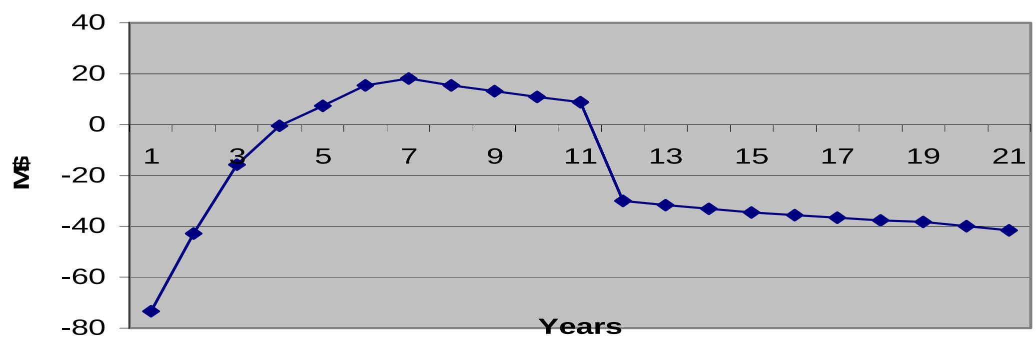
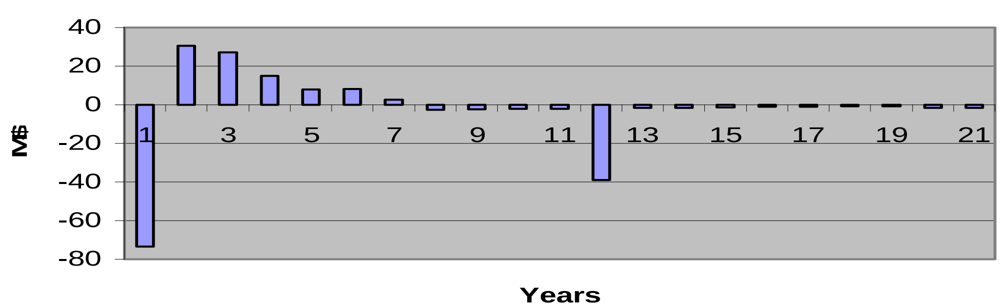


Figure 28: Net Cash Flow – Best Cost Estimate – W/O PTC



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 competition among technologies. 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 (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. Learning curves make it possible to answer such questions because they provide a simple, quantitative relationship between price and the cumulative production 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 29. 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.

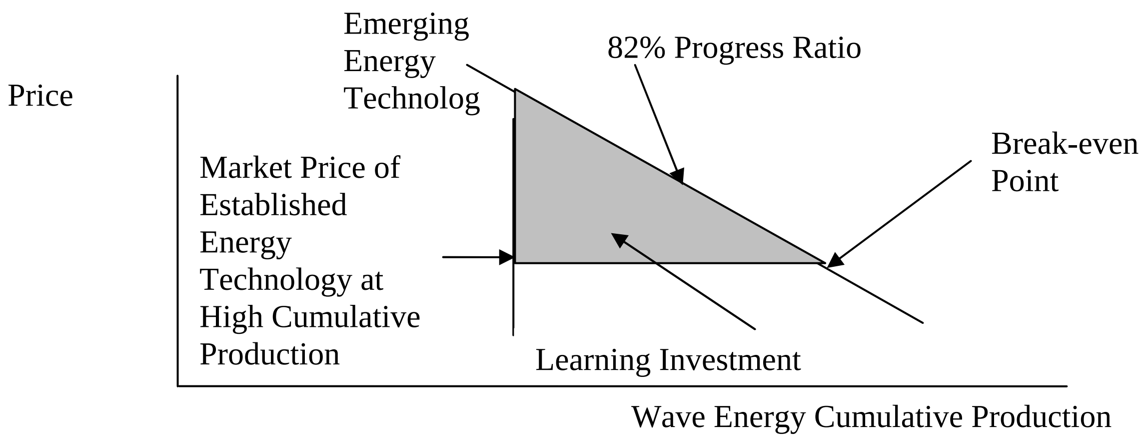


Figure 29: Learning Investment Required

12. Comparison with Commercial Scale Wind Power Plant

The costs (in 2004$) of a pilot offshore WEC device are described in Section 7 using the production experience gained by OPD from the build of the first prototype machine. The costs (in 2004$) 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 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 $1,200/kW in 1997$[9]. 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"[10]. 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 Hawaii 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. This is illustrated in Figure 30 which shows the learning curves for a 500kW and 750kW Pelamis device in comparison to wind.

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

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

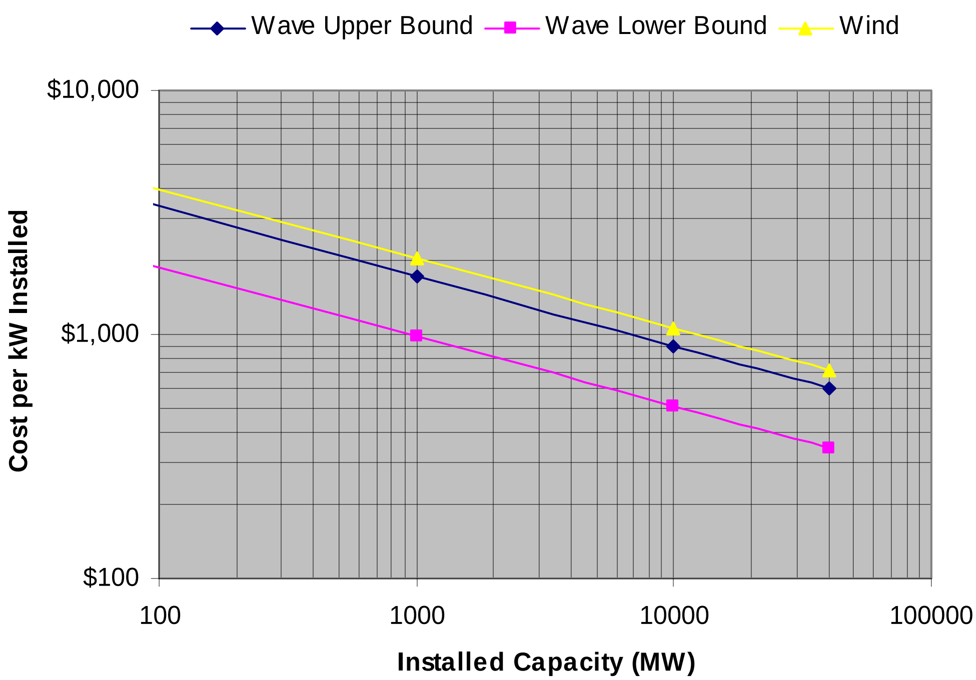

Figure 30: Installed Cost per kW installed as a Function of Installed Capacity

In order to make a meaningful comparison between wind and wave, a levelized comparison using COE numbers is required. In order to predict the cost of electricity for wave, a forecast of O&M cost is required. The following facts were considered in coming up with a conclusion:

- 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 (assuming the same cumulative production volume)
- 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, it was found a reasonable assumption for O&M cost for mature wave power technology to be 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 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 (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**

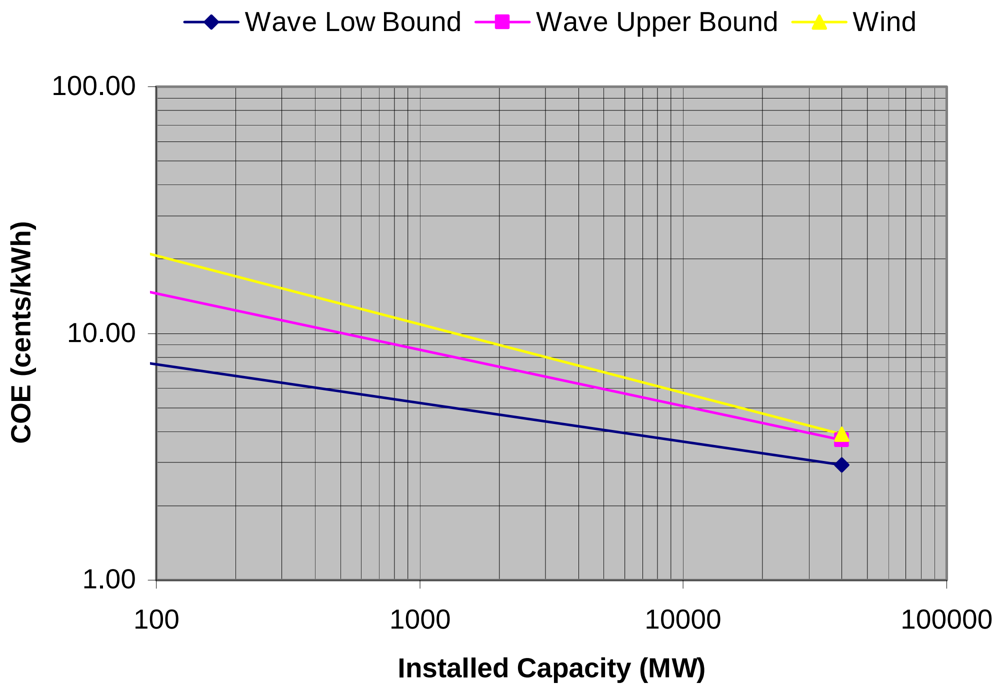

Figure 31: Levelized COE comparison to wind

As shown in Figure 31, wave energy at essentially no learning is not economically competitive with wind energy at 40,000 MW of cumulative production volume. The learning curve of Figure 31 shows that at worst, the economics of wave energy is about equal to wind energy at any cumulative production volume less than 40,000 MW, and at best, is significantly better that wind energy. 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.

The techno-economic assessment forecast made by the Project Team is that wave energy will become commercially competitive with the current 40,000 MW installed land-based wind technology at a cumulative production volume of 10,000 MW or less. The size of a wave machine will be an order of magnitude smaller that an equivalent rated power wind machine and therefore is forecast to be less costly. The operations and maintenance (O&M) cost for a remotely located offshore wave machine in a somewhat hostile environment will, however, be higher than for a land based wind machine. The results of this study show that the lower cost machine outweighs the additional O&M cost on a cost of electricity basis. The challenge to the wave energy industry is to reduce the O&M cost of offshore wave energy to order to compete with onshore wind energy at large cumulative production volumes (> 40,000 MW).

In addition to the economics, there are other compelling arguments for investing in offshore wave energy. The first is that, with proper siting, converting ocean wave energy to electricity is believed to be one of the most environmentally benign ways of electricity generation. Second, offshore wave energy offers a way to avoid the 'Not In My Backyard' (NIMBY) issues that plague many energy infrastructure projects, from nuclear, coal and wind generation to transmission and distribution facilities. Because these devices have a very low profile and are located at a distance from the shore, they are generally not visible. Third, because wave energy is less intermittent that other renewable technologies such as solar and wind, it offers the possibility of being dispatchable and earning a capacity payment (this needs to be explored – see recommendations in Section 13)

The key characteristic of wave energy that promises to enable it to be one of the lowest cost renewable technologies is its high power density. Solar and wind power systems use a very diffuse solar and wind energy source. Processes in the ocean tend to concentrate the solar and wind energy into ocean waves making it easier and cheaper to harvest.

Lastly, since a diversity of energy sources is the bedrock of a robust electricity system, to overlook wave energy is inconsistent with our national needs and goals. Wave energy is an energy source that is too important to overlook.

13. Conclusions

Pilot Offshore Wave Power Plant

Makapuu Point, Oahu, Hawaii has the potential to be a very good area for locating an offshore wave power plant. While manufacturing facilities are limited, there is excellent R&D infrastructure in place, which can be leveraged for a demonstration system on the Makai pier on the southeast (windward) shore of Oahu.

Commercial Scale Offshore Wave Power Plants

The Hawaii commercial scale power plant design, performance and cost 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, may 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 cost, uncertainties and risk are too high at this point in time.

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 would not be the first electricity generation technology to reach the commercial market place without Federal Government subsidy.

Techno-Economic Challenges

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. There is 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 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)?

- 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)?

- Will the performance, reliability and cost projections be realized in practice once wave energy devices are deployed and tested?

14. Recommendations

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

E2I EPRI Global makes the following recommendations to the Hawaii Electricity Stakeholders:

1. Monitor the OPT demonstration project in Hawaii and the OPD Pelamis demonstration project in Scotland and update the performance, reliability and cost projections as appropriate based on these tests.

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

   In order to accelerate the growth and development of an ocean energy industry in the United States and to address and answer the many techno-economic challenges, a technology roadmap is need which can most effectively be accomplished through leadership at the national level.

   The development of ocean energy technology and the deployment of this clean renewable energy technology would be greatly accelerated if the Federal Government were supporting the development. Appropriate roles for the Federal Government in ocean energy development could include some, or all, of the following:

   - Providing leadership for the development of an ocean energy RD&D program to fill known R&D gaps identified in this report, and to accelerate technology development and prototype system deployment
   - Operating a national offshore wave test center to test the performance and reliability of prototype ocean energy systems under real conditions
   - Development of design and testing standards for ocean energy devices
   - Joining the International Energy Agency Ocean Energy Systems Implementing Agreement to collaborate RD&D activities, and appropriate ocean energy policies with other governments and organizations
   - Leading activities to streamline the process for licensing, leasing, and permitting renewable energy facilities in U.S. waters
   - Studying provision of production tax credits, renewable energy credits, and other incentives to spur private investment in ocean energy technologies and projects, and implementing appropriate incentives to accelerate ocean energy deployment
   - Ensuring that the public receives a fair return from the use of ocean energy resources
   - Ensuring that development rights are allocated through a transparent process that takes into account state, local, and public concerns.

3. Encourage R&D at universities such as University of Hawaii

4. Seek funding for a pilot feasibility demonstration plant at Makapuu Point, Hawaii.

   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:

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

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 Hawaii January

		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	
		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)																	
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	1	0	0	0	0	0	0	0	0	0	0	1
3.75	4.25	**4**	0	0	0	0	0	1	2	2	1	0	0	0	0	1	0	0	0	6
3.25	3.75	**3.5**	0	0	0	0	1	2	7	6	4	4	3	1	0	3	0	0	0	31
2.75	3.25	**3**	0	0	0	1	5	7	15	14	7	14	12	7	0	3	0	0	0	85
2.25	2.75	**2.5**	0	0	0	4	7	16	38	15	15	22	24	14	0	2	0	0	0	157
1.75	2.25	**2**	0	0	0	14	7	14	42	35	35	50	50	17	0	1	0	1	0	265
1.25	1.75	**1.5**	0	0	3	5	3	12	32	24	23	32	25	12	0	3	0	0	0	175
0.75	1.25	**1**	0	0	1	2	1	3	6	2	3	3	3	0	0	1	0	0	0	24
0.25	0.75	**0.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	4	25	23	56	144	97	87	126	117	51	0	13	0	1	0	744

Table A-2: Scatter Diagram Hawaii February

		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	
		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	
Hs and Tp bin boundaries			Tp (sec)																	
Lower Hs	Upper Hs	Hs (m)	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	20	
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	1	0	0	0	0	0	*1*
4.25	4.75	**4.5**	0	0	0	0	0	0	0	0	1	0	1	1	0	1	0	0	0	*3*
3.75	4.25	**4**	0	0	0	0	0	0	2	1	3	1	1	1	0	1	0	0	0	*8*
3.25	3.75	**3.5**	0	0	0	0	0	1	10	2	1	2	1	1	0	1	0	0	0	*17*
2.75	3.25	**3**	0	0	0	0	3	8	13	4	11	6	7	3	2	0	0	0	0	*56*
2.25	2.75	**2.5**	0	0	0	1	6	8	11	12	25	29	17	11	1	1	0	0	0	*122*
1.75	2.25	**2**	0	0	0	6	12	5	17	16	38	51	37	10	1	1	0	0	0	*194*
1.25	1.75	**1.5**	0	0	3	5	0	6	33	30	53	48	26	14	2	5	0	0	0	*225*
0.75	1.25	**1**	0	0	1	1	0	4	18	9	10	6	4	0	0	0	0	0	0	*52*
0.25	0.75	**0.5**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
0	0.25	**0.125**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
			0	*0*	*3*	*12*	*21*	*32*	*104*	*74*	*140*	*143*	*94*	*41*	*5*	*9*	*0*	*0*	*0*	***678***

Table A-3: Scatter Diagram Hawaii March

		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	
		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)																	
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	1	0	0	0	0	0	0	0	0	0	0	1
4.75	5.25	**5**	0	0	0	0	0	0	1	2	0	0	1	1	0	0	0	0	0	4
4.25	4.75	**4.5**	0	0	0	0	0	0	3	3	0	0	0	1	0	0	0	0	0	6
3.75	4.25	**4**	0	0	0	0	0	1	4	1	0	0	1	1	0	1	0	0	0	7
3.25	3.75	**3.5**	0	0	0	0	1	2	5	1	0	3	3	2	0	0	0	0	0	16
2.75	3.25	**3**	0	0	0	0	2	4	13	2	3	3	6	2	0	0	0	0	0	35
2.25	2.75	**2.5**	0	0	0	10	18	14	19	7	8	11	13	4	0	0	0	0	0	104
1.75	2.25	**2**	0	0	1	20	21	23	24	18	24	40	26	12	1	5	0	0	0	215
1.25	1.75	**1.5**	0	0	8	22	9	21	49	27	37	43	33	11	1	3	0	0	0	264
0.75	1.25	**1**	0	0	1	2	3	16	17	10	12	16	13	1	0	1	0	0	0	90
0.25	0.75	**0.5**	0	0	0	0	0	1	2	0	1	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	9	53	53	81	137	71	84	117	96	33	2	9	0	0	0	744

Table A-4: Scatter Diagram Hawaii April

		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	
		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)									
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	1
3.75	4.25	4	0	0	0	0	0	0	2	2	0	0	0	0	0	0	0	0	0	5
3.25	3.75	3.5	0	0	0	0	0	1	7	5	3	0	1	1	0	0	0	0	0	17
2.75	3.25	3	0	0	0	0	3	10	12	3	4	2	7	3	0	0	0	0	0	45
2.25	2.75	2.5	0	0	0	4	18	42	30	7	9	11	12	5	0	0	0	0	0	138
1.75	2.25	2	0	0	1	24	28	45	42	13	16	31	20	8	2	5	0	0	0	235
1.25	1.75	1.5	0	0	3	16	14	45	53	14	33	35	21	6	1	2	0	0	0	245
0.75	1.25	1	0	0	0	0	3	7	8	1	3	6	5	2	0	0	0	0	0	35
0.25	0.75	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		720	0	0	4	45	66	148	154	47	68	85	66	25	3	7	0	1	0	720

Table A-5: Scatter Diagram Hawaii May

		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	
		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)									
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	1
3.25	3.75	3.5	0	0	0	0	0	0	1	2	2	0	0	0	0	0	0	0	0	5
2.75	3.25	3	0	0	0	0	0	4	4	1	3	1	0	1	0	0	0	0	0	14
2.25	2.75	2.5	0	0	0	3	10	20	31	4	4	7	4	3	0	1	0	0	0	87
1.75	2.25	2	0	0	2	29	31	49	60	13	13	17	9	9	1	5	0	0	0	236
1.25	1.75	1.5	0	0	10	35	27	55	44	15	18	14	16	11	3	5	0	0	0	254
0.75	1.25	1	0	0	5	6	9	20	33	17	8	12	16	11	2	4	2	1	0	146
0.25	0.75	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	17	73	79	149	172	52	47	51	45	35	5	15	2	1	0	744

Table A-6: Scatter Diagram Hawaii June

		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	
		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)									
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	1	1	0	0	0	0	0	0	0	0	0	0	1
2.25	2.75	2.5	0	0	0	1	8	19	6	0	0	0	0	1	0	2	1	0	0	39
1.75	2.25	2	0	0	2	41	49	70	42	2	2	2	12	7	4	2	1	0	0	236
1.25	1.75	1.5	0	0	28	61	63	100	32	7	7	17	42	23	2	4	0	0	0	386
0.75	1.25	1	0	0	2	3	8	23	7	1	2	2	6	2	0	1	0	0	0	57
0.25	0.75	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		720	0	0	32	106	128	213	88	10	11	21	60	33	6	8	3	0	0	720

Table A-7: Scatter Diagram Hawaii July

		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	
		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)																	
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	1	1	0	0	0	0	0	0	0	0	0	0	3
2.25	2.75	2.5	0	0	0	3	9	19	25	4	1	0	0	0	0	0	0	0	0	61
1.75	2.25	2	0	0	3	33	48	96	43	4	4	6	11	12	0	3	1	1	0	263
1.25	1.75	1.5	0	0	17	59	62	86	40	11	7	17	33	16	2	5	0	1	1	356
0.75	1.25	1	0	2	11	15	7	5	7	2	1	3	2	5	0	0	0	0	0	61
0.25	0.75	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	2	30	110	125	206	116	22	13	27	47	33	2	8	1	2	1	744

Table A-8: Scatter Diagram Hawaii August

		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	
		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)																	
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	1	0	0	0	0	0	0	*1*
3.25	3.75	3.5	0	0	0	0	0	0	0	1	0	2	0	0	0	0	0	0	0	*3*
2.75	3.25	3	0	0	0	0	0	3	5	2	1	2	1	0	0	0	0	0	0	*14*
2.25	2.75	2.5	0	0	0	2	3	19	10	1	2	1	0	2	0	0	0	0	0	*39*
1.75	2.25	2	0	0	3	38	33	68	30	3	0	4	7	5	0	0	0	0	0	*191*
1.25	1.75	1.5	0	0	33	84	58	80	50	13	11	17	22	19	0	5	0	0	0	*392*
0.75	1.25	1	0	0	3	9	12	18	18	8	9	14	4	5	0	0	0	0	0	*102*
0.25	0.75	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*1*
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*	*39*	*134*	*106*	*188*	*113*	*28*	*24*	*39*	*36*	*30*	*1*	*5*	*0*	*0*	*0*	*744*

Table A-9: Scatter Diagram Hawaii September

		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	
		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)																	
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	1
2.75	3.25	3	0	0	0	0	0	0	0	1	0	0	1	0	0	0	0	0	0	3
2.25	2.75	2.5	0	0	0	0	4	6	6	1	2	0	1	0	0	0	0	0	0	21
1.75	2.25	2	0	0	0	20	22	43	23	5	9	16	12	2	0	0	0	0	0	153
1.25	1.75	1.5	0	0	23	66	58	98	67	23	24	17	14	14	1	2	0	0	0	409
0.75	1.25	1	0	0	2	7	9	29	32	13	14	11	11	5	0	1	0	0	0	133
0.25	0.75	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
		720	0	0	26	94	94	176	128	44	50	44	40	21	1	3	0	0	0	720

Table A-10: Scatter Diagram Hawaii October

		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	
		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)									
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	1	2	2	0	1	1	1	1	0	0	0	0	0	8
2.25	2.75	2.5	0	0	0	2	6	11	16	5	8	9	8	2	2	0	0	0	0	68
1.75	2.25	2	0	0	0	19	46	60	66	17	25	25	23	8	3	1	0	0	0	291
1.25	1.75	1.5	0	0	7	15	37	41	46	32	35	41	29	14	0	2	0	0	0	300
0.75	1.25	1	0	0	1	1	8	18	13	7	13	10	5	0	0	0	0	0	0	76
0.25	0.75	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	8	37	98	132	143	61	82	86	66	24	5	3	0	0	0	744

Table A-11: Scatter Diagram Hawaii November

		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	
		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)									
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	1	0	1	1	1	0	0	*3*
4.25	4.75	4.5	0	0	0	0	0	0	0	0	0	0	2	0	1	1	0	0	0	*3*
3.75	4.25	4	0	0	0	0	0	0	0	1	1	0	5	3	0	0	1	0	0	*9*
3.25	3.75	3.5	0	0	0	0	0	1	5	2	5	3	7	3	0	0	0	0	0	*24*
2.75	3.25	3	0	0	0	0	3	4	14	8	5	7	7	2	0	1	0	0	0	*50*
2.25	2.75	2.5	0	0	0	7	16	22	32	11	11	12	17	5	0	1	0	0	0	*133*
1.75	2.25	2	0	0	0	19	17	45	81	30	43	39	22	6	0	2	0	0	0	*303*
1.25	1.75	1.5	0	0	2	7	5	33	41	19	16	27	20	3	0	3	0	0	0	*176*
0.75	1.25	1	0	0	0	0	2	8	4	1	2	3	0	0	0	0	0	0	0	*18*
0.25	0.75	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
0	0.25	0.125	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*0*
		720	*0*	*0*	*2*	*33*	*43*	*112*	*176*	*71*	*82*	*90*	*80*	*21*	*2*	*7*	*1*	*0*	*0*	*720*

Table A-12: Scatter Diagram Hawaii December

		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	
		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)									
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	2	0	0	0	0	0	0	0	2
4.25	4.75	4.5	0	0	0	0	0	0	1	0	1	1	1	1	0	0	0	0	0	4
3.75	4.25	4	0	0	0	0	0	1	1	0	1	4	1	0	0	0	0	0	0	6
3.25	3.75	3.5	0	0	0	0	1	3	3	3	2	5	2	3	0	1	0	0	0	24
2.75	3.25	3	0	0	0	0	3	9	24	17	7	7	10	5	0	1	0	0	0	82
2.25	2.75	2.5	0	0	0	3	11	19	53	29	12	13	20	9	0	2	0	0	0	172
1.75	2.25	2	0	0	2	12	15	34	87	22	20	27	37	15	0	2	0	1	0	271
1.25	1.75	1.5	0	1	2	6	2	17	27	9	20	30	17	7	0	3	0	0	0	142
0.75	1.25	1	0	0	1	0	1	8	5	2	8	5	8	4	0	1	0	0	0	41
0.25	0.75	0.5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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	1	4	22	33	90	199	83	70	95	96	42	0	9	0	1	0	744

Appendix B Com'l Plant Economics Worksheet – Regulated Utility – With PTC

SHEET 1 - 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 including insurance
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 Columnn 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 Columnn 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

SHEET 1 - TOTAL PLANT COST (TPC) - 2004$

TPC Component	Unit	Unit Cost	Total Cost (2004$)	
Procurement				
Onshore Trans & Grid I/C	1	$3,084,000	$3,084,000	
Subsea Cables	1	$3,950,000	$3,950,000	
Mooring	180	$137,222	$24,699,960	
Power Conversion Modules (set of 3)	180	$623,961	$112,312,980	
Concrete Structure Sections	180	$244,800	$44,064,000	
Facilities	1	$12,000,000	$12,000,000	
Installation	1	$11,229,000	$11,229,000	
Construction Management (5%)	1	$10,566,997	$10,566,997	
TOTAL			$221,906,937	

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	$110,953,469	$8,321,510	$7,513,779	$118,467,247
2007	$110,953,469	$8,321,510	$13,568,901	$124,522,369
Total	$221,906,937	$16,643,020	$21,082,680	$242,989,617

SHEET 2 - ANNUAL OPERATING AND MAINTENANCE COST (AO&M) - 2004$

Costs	Yrly Cost	Amount	
LABOR	$2,322,000	$2,322,000	
PARTS AND SUPPLIES (2%)	$4,941,000	$4,941,000	
INSURANCE (2%)	$4,941,000	$4,941,000	
Total		$12,204,000	

SHEET 3 - 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	$16,804,000	
Total		$26,562,000	

SHEET 4 - 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	Hawaii	
6	State Tax Rate	6.02	%
	Composite Tax Rate (t)	0.389	
	t/(1-t)	0.6367	
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	9.73	%
15	Inflation Rate = 3%	3	%
	Real Discount Rate Before-Tax	7.52	%
	Real Discount Rate After-Tax	6.53	%
16	Federal Investment Tax Credit	10	% 1st year only
17	Federal Production Tax Credit	0.018	$/kWh for 1st 10 years
18	State Investment Tax Credit		% of TPI up to $2.5M
19	State Investment Tax Credit Limit		Credit - 1st year only for ≥ $10M plant
20	State Production Tax Credit	0	$/kWh for 1st 10 years

SHEET 5 -NET PRESENT VALUE (NPV) - 2004 $

TPI = $242,989,617

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	**242,989,617**					**242,989,617**
2008	242,989,617	12,149,481	12,149,481	0.2000	14,273,210	216,566,926
2009	242,989,617	12,149,481	24,298,962	0.3200	25,691,778	178,725,667
2010	242,989,617	12,149,481	36,448,443	0.1920	13,511,972	153,064,214
2011	242,989,617	12,149,481	48,597,923	0.1152	6,204,089	134,710,644
2012	242,989,617	12,149,481	60,747,404	0.1152	6,204,089	116,357,075
2013	242,989,617	12,149,481	72,896,885	0.0576	723,176	103,484,418
2014	242,989,617	12,149,481	85,046,366	0.0000	-4,757,737	96,092,674
2015	242,989,617	12,149,481	97,195,847	0.0000	-4,757,737	88,700,930
2016	242,989,617	12,149,481	109,345,328	0.0000	-4,757,737	81,309,186
2017	242,989,617	12,149,481	121,494,808	0.0000	-4,757,737	73,917,441
2018	242,989,617	12,149,481	133,644,289	0.0000	-4,757,737	66,525,697
2019	242,989,617	12,149,481	145,793,770	0.0000	-4,757,737	59,133,953
2020	242,989,617	12,149,481	157,943,251	0.0000	-4,757,737	51,742,209
2021	242,989,617	12,149,481	170,092,732	0.0000	-4,757,737	44,350,465
2022	242,989,617	12,149,481	182,242,213	0.0000	-4,757,737	36,958,721
2023	242,989,617	12,149,481	194,391,693	0.0000	-4,757,737	29,566,977
2024	242,989,617	12,149,481	206,541,174	0.0000	-4,757,737	22,175,232
2025	242,989,617	12,149,481	218,690,655	0.0000	-4,757,737	14,783,488
2026	242,989,617	12,149,481	230,840,136	0.0000	-4,757,737	7,391,744
2027	242,989,617	12,149,481	242,989,617	0.0000	-4,757,737	0

SHEET 6 - CAPITAL REVENUE REQUIREMENTS

TPI = $242,989,617

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	216,566,926	14,639,924	2,956,139	5,684,882	12,149,481	16,853,727	29,698,962	22,585,191
2009	178,725,667	12,081,855	2,439,605	4,691,549	12,149,481	22,863,731	5,400,000	48,826,221
2010	153,064,214	10,347,141	2,089,327	4,017,936	12,149,481	14,115,689	5,400,000	37,319,573
2011	134,710,644	9,106,440	1,838,800	3,536,154	12,149,481	8,762,194	5,400,000	29,993,069
2012	116,357,075	7,865,738	1,588,274	3,054,373	12,149,481	8,112,459	5,400,000	27,370,325
2013	103,484,418	6,995,547	1,412,562	2,716,466	12,149,481	4,128,933	5,400,000	22,002,989
2014	96,092,674	6,495,865	1,311,665	2,522,433	12,149,481	339,438	5,400,000	17,418,882
2015	88,700,930	5,996,183	1,210,768	2,328,399	12,149,481	77,763	5,400,000	16,362,594
2016	81,309,186	5,496,501	1,109,870	2,134,366	12,149,481	-183,913	5,400,000	15,306,306
2017	73,917,441	4,996,819	1,008,973	1,940,333	12,149,481	-445,588	5,400,000	14,250,018
2018	66,525,697	4,497,137	908,076	1,746,300	12,149,481	-707,264		18,593,730
2019	59,133,953	3,997,455	807,178	1,552,266	12,149,481	-968,939		17,537,442
2020	51,742,209	3,497,773	706,281	1,358,233	12,149,481	-1,230,615		16,481,154
2021	44,350,465	2,998,091	605,384	1,164,200	12,149,481	-1,492,290		15,424,866
2022	36,958,721	2,498,410	504,487	970,166	12,149,481	-1,753,966		14,368,578
2023	29,566,977	1,998,728	403,589	776,133	12,149,481	-2,015,641		13,312,290
2024	22,175,232	1,499,046	302,692	582,100	12,149,481	-2,277,317		12,256,002
2025	14,783,488	999,364	201,795	388,067	12,149,481	-2,538,992		11,199,714
2026	7,391,744	499,682	100,897	194,033	12,149,481	-2,800,668		10,143,426
2027	0	0	0	0	12,149,481	-3,062,343		9,087,137
Sum of Annual Capital Revenue Requirements								389,839,502

SHEET 7 - FIXED CHARGE RATE (FCR) - NOMINAL AND REAL LEVELIZED

TPI = $242,989,617

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	22,585,191	0.9114	20,584,004	20,668,649	0.9387	19,402,398
2009	48,826,221	0.8306	40,556,950	43,381,465	0.8812	38,228,815
2010	37,319,573	0.7570	28,252,373	32,192,192	0.8272	26,630,571
2011	29,993,069	0.6900	20,694,039	25,118,723	0.7766	19,506,116
2012	27,370,325	0.6288	17,211,170	22,254,579	0.7290	16,223,178
2013	22,002,989	0.5731	12,610,091	17,369,363	0.6843	11,886,220
2014	17,418,882	0.5223	9,098,355	13,350,122	0.6424	8,576,072
2015	16,362,594	0.4760	7,789,343	12,175,306	0.6030	7,342,203
2016	15,306,306	0.4339	6,640,873	11,057,601	0.5661	6,259,660
2017	14,250,018	0.3954	5,634,771	9,994,676	0.5314	5,311,312
2018	18,593,730	0.3604	6,700,905	12,661,425	0.4989	6,316,246
2019	17,537,442	0.3285	5,760,223	11,594,315	0.4683	5,429,562
2020	16,481,154	0.2993	4,933,632	10,578,625	0.4396	4,650,421
2021	15,424,866	0.2728	4,208,299	9,612,266	0.4127	3,966,726
2022	14,368,578	0.2487	3,572,770	8,693,226	0.3874	3,367,679
2023	13,312,290	0.2266	3,016,825	7,819,567	0.3637	2,843,647
2024	12,256,002	0.2065	2,531,350	6,989,426	0.3414	2,386,041
2025	11,199,714	0.1882	2,108,223	6,201,010	0.3205	1,987,202
2026	10,143,426	0.1716	1,740,205	5,452,591	0.3008	1,640,310
2027	9,087,137	0.1564	1,420,852	4,742,509	0.2824	1,339,289
	389,839,502		205,065,251	291,907,636		193,293,667

	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	205,065,251		193,293,667
2. Escalation Rate	3%		3%
3. After Tax Discount Rate = i	9.72%		6.53%
4. Capital recovery factor value = i(1+i)"/(1+i)"-1 where book life = n and discount rate = i	0.115239127		0.090945809
5. The levelized annual charges (end of year) = Present Value (Item 1) * Capital Recovery Factor (Item 4)	23,631,541		17,579,249
6. Booked Cost	242,989,617		242,989,617
7. The levelized annual fixed charge rate (levelized annual charges divided by the booked cost)	**0.0973**		**0.0723**

SHEET 8 - 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	$242,989,617	$	From TPI
FCR	9.73%	%	From FCR
AO&M	$12,204,000	$	From AO&M
LO&R = O&R/Life	$1,328,100	$	From LO&R
AEP =	300,000	MWeh/yr	From Assumptions
COE - TPI X FCR	7.88	cents/kWh	
COE - AO&M	4.07	cents/kWh	
COE - LO&R	0.44	cents/kWh	
COE	$0.1239	$/kWh	Calculated
COE	**12.39**	cents/kWh	Calculated

REAL RATES

	Value	Units	From
TPI	$242,989,617	$	From TPI
FCR	7.23%	%	From FCR
AO&M	$12,204,000	$	From AO&M
LO&R = O&R/Life	$1,328,100	$	From LO&R
AEP =	300,000	MWeh/yr	From Assumptions
COE - TPI X FCR	5.86	cents/kWh	
COE - AO&M	4.07	cents/kWh	
COE - LO&R	0.44	cents/kWh	
COE	$0.1037	$/kWh	Calculated
COE	**10.37**	cents/kWh	Calculated

Appendix C Com'l Plant Economics Worksheet –Utility —Without PTC

SHEET 1 - 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 including insurance
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 Columnn 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 Columnn 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

SHEET 1 - TOTAL PLANT COST (TPC) - 2004$

TPC Component	Unit	Unit Cost	Total Cost (2004$)	
Procurement				
Onshore Trans & Grid I/C	1	$3,084,000	$3,084,000	
Subsea Cables	1	$3,950,000	$3,950,000	
Mooring	180	$137,222	$24,699,960	
Power Conversion Modules (set of 3)	180	$623,961	$112,312,980	
Concrete Structure Sections	180	$244,800	$44,064,000	
Facilities	1	$12,000,000	$12,000,000	
Installation	1	$11,229,000	$11,229,000	
Construction Management (5%)	1	$10,566,997	$10,566,997	
TOTAL			$221,906,937	

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	$110,953,469	$8,321,510	$7,513,779	$118,467,247
2007	$110,953,469	$8,321,510	$13,568,901	$124,522,369
Total	$221,906,937	$16,643,020	$21,082,680	$242,989,617

SHEET 2 - ANNUAL OPERATING AND MAINTENANCE COST (AO&M) - 2004$

Costs	Yrly Cost	Amount	
LABOR	$2,322,000	$2,322,000	
PARTS AND SUPPLIES (2%)	$4,941,000	$4,941,000	
INSURANCE (2%)	$4,941,000	$4,941,000	
Total		$12,204,000	

SHEET 3 - 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	$16,804,000	
Total		$26,562,000	

SHEET 4 - 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	Hawaii	
6	State Tax Rate	6.2	%
	Composite Tax Rate (t)	0.389	%
	t/(1-t)	0.6367	
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	8.52	%
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	0	% 1st year only % of TPI up to $2.5M
19	State Production Tax Credit	0	
20	Avoided cost electricity price - 2002$	0.0841	$/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	

SHEET 5 -NET PRESENT VALUE (NPV) - 2004 $

TPI = $242,989,617

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	**242,989,617**					**242,989,617**
2008	242,989,617	12,149,481	12,149,481	0.2000	14,273,210	216,566,926
2009	242,989,617	12,149,481	24,298,962	0.3200	25,691,778	178,725,667
2010	242,989,617	12,149,481	36,448,443	0.1920	13,511,972	153,064,214
2011	242,989,617	12,149,481	48,597,923	0.1152	6,204,089	134,710,644
2012	242,989,617	12,149,481	60,747,404	0.1152	6,204,089	116,357,075
2013	242,989,617	12,149,481	72,896,885	0.0576	723,176	103,484,418
2014	242,989,617	12,149,481	85,046,366	0.0000	-4,757,737	96,092,674
2015	242,989,617	12,149,481	97,195,847	0.0000	-4,757,737	88,700,930
2016	242,989,617	12,149,481	109,345,328	0.0000	-4,757,737	81,309,186
2017	242,989,617	12,149,481	121,494,808	0.0000	-4,757,737	73,917,441
2018	242,989,617	12,149,481	133,644,289	0.0000	-4,757,737	66,525,697
2019	242,989,617	12,149,481	145,793,770	0.0000	-4,757,737	59,133,953
2020	242,989,617	12,149,481	157,943,251	0.0000	-4,757,737	51,742,209
2021	242,989,617	12,149,481	170,092,732	0.0000	-4,757,737	44,350,465
2022	242,989,617	12,149,481	182,242,213	0.0000	-4,757,737	36,958,721
2023	242,989,617	12,149,481	194,391,693	0.0000	-4,757,737	29,566,977
2024	242,989,617	12,149,481	206,541,174	0.0000	-4,757,737	22,175,232
2025	242,989,617	12,149,481	218,690,655	0.0000	-4,757,737	14,783,488
2026	242,989,617	12,149,481	230,840,136	0.0000	-4,757,737	7,391,744
2027	242,989,617	12,149,481	242,989,617	0.0000	-4,757,737	0

TPI = $242,989,617

End of Year	Net Book A	Returns to Equity Common B	Returns to Equity Pref C	Interest on Debt D	Book Dep E	Income Tax on Equity Return F	ITC and PTC H	Capital Revenue Req'ts I
2008	216,566,926	14,639,924	2,956,139	5,684,882	12,149,481	16,853,727	24,298,962	27,985,191
2009	178,725,667	12,081,855	2,439,605	4,691,549	12,149,481	22,863,731	0	54,226,221
2010	153,064,214	10,347,141	2,089,327	4,017,936	12,149,481	14,115,689	0	42,719,573
2011	134,710,644	9,106,440	1,838,800	3,536,154	12,149,481	8,762,194	0	35,393,069
2012	116,357,075	7,865,738	1,588,274	3,054,373	12,149,481	8,112,459	0	32,770,325
2013	103,484,418	6,995,547	1,412,562	2,716,466	12,149,481	4,128,933	0	27,402,989
2014	96,092,674	6,495,865	1,311,665	2,522,433	12,149,481	339,438	0	22,818,882
2015	88,700,930	5,996,183	1,210,768	2,328,399	12,149,481	77,763	0	21,762,594
2016	81,309,186	5,496,501	1,109,870	2,134,366	12,149,481	-183,913	0	20,706,306
2017	73,917,441	4,996,819	1,008,973	1,940,333	12,149,481	-445,588	0	19,650,018
2018	66,525,697	4,497,137	908,076	1,746,300	12,149,481	-707,264	0	18,593,730
2019	59,133,953	3,997,455	807,178	1,552,266	12,149,481	-968,939		17,537,442
2020	51,742,209	3,497,773	706,281	1,358,233	12,149,481	-1,230,615		16,481,154
2021	44,350,465	2,998,091	605,384	1,164,200	12,149,481	-1,492,290		15,424,866
2022	36,958,721	2,498,410	504,487	970,166	12,149,481	-1,753,966		14,368,578
2023	29,566,977	1,998,728	403,589	776,133	12,149,481	-2,015,641		13,312,290
2024	22,175,232	1,499,046	302,692	582,100	12,149,481	-2,277,317		12,256,002
2025	14,783,488	999,364	201,795	388,067	12,149,481	-2,538,992		11,199,714
2026	7,391,744	499,682	100,897	194,033	12,149,481	-2,800,668		10,143,426
2027	0	0	0	0	12,149,481	-3,062,343		9,087,137
Sum of Annual Capital Revenue Requirements								443,839,502

SHEET 7 - FIXED CHARGE RATE (FCR) - NOMINAL AND REAL LEVELIZED

TPI = $242,989,617

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	27,985,191	0.9114	25,505,530	25,610,414	0.9387	24,041,409
2009	54,226,221	0.8306	45,042,399	48,179,295	0.8812	42,456,781
2010	42,719,573	0.7570	32,340,383	36,850,279	0.8272	30,483,913
2011	35,393,069	0.6900	24,419,827	29,641,138	0.7766	23,018,029
2012	32,770,325	0.6288	20,606,830	26,645,273	0.7290	19,423,913
2013	27,402,989	0.5731	15,704,874	21,632,173	0.6843	14,803,350
2014	22,818,882	0.5223	11,918,922	17,488,773	0.6424	11,234,727
2015	21,762,594	0.4760	10,359,990	16,193,414	0.6030	9,765,284
2016	20,706,306	0.4339	8,983,745	14,958,676	0.5661	8,468,041
2017	19,650,018	0.3954	7,770,050	13,782,127	0.5314	7,324,017
2018	18,593,730	0.3604	6,700,905	12,661,425	0.4989	6,316,246
2019	17,537,442	0.3285	5,760,223	11,594,315	0.4683	5,429,562
2020	16,481,154	0.2993	4,933,632	10,578,625	0.4396	4,650,421
2021	15,424,866	0.2728	4,208,299	9,612,266	0.4127	3,966,726
2022	14,368,578	0.2487	3,572,770	8,693,226	0.3874	3,367,679
2023	13,312,290	0.2266	3,016,825	7,819,567	0.3637	2,843,647
2024	12,256,002	0.2065	2,531,350	6,989,426	0.3414	2,386,041
2025	11,199,714	0.1882	2,108,223	6,201,010	0.3205	1,987,202
2026	10,143,426	0.1716	1,740,205	5,452,591	0.3008	1,640,310
2027	9,087,137	0.1564	1,420,852	4,742,509	0.2824	1,339,289
	443,839,502		238,645,833	335,326,522		224,946,586

	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	238,645,833		224,946,586
2. Escalation Rate	3%		3%
3. After Tax Discount Rate = i	9.72%		6.53%
4. Capital recovery factor value = i(1+i)"/(1+i)"-1 where book life = n and discount rate = i	0.115239127		0.090945809
5. The levelized annual charges (end of year) = Present Value (Item 1) * Capital Recovery Factor (Item 4)	27,501,338		20,457,949
6. Booked Cost	242,989,617		242,989,617
7. The levelized annual fixed charge rate (levelized annual charges divided by the booked cost)	**0.1132**		**0.0842**

SHEET 8 - 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	$242,989,617	$	From TPI
FCR	11.32%	%	From FCR
AO&M	$12,204,000	$	From AO&M
LO&R = O&R/Life	$1,328,100	$	From LO&R
AEP =	300,000	MWeh/yr	From Assumptions
COE - TPI X FCR	9.17	cents/kWh	
COE - AO&M	4.07	cents/kWh	
COE - LO&R	0.44	cents/kWh	
COE	$0.1368	$/kWh	Calculated
COE	**13.68**	cents/kWh	Calculated

REAL RATES

	Value	Units	From
TPI	$242,989,617	$	From TPI
FCR	8.42%	%	From FCR
AO&M	$12,204,000	$	From AO&M
LO&R = O&R/Life	$1,328,100	$	From LO&R
AEP =	300,000	MWeh/yr	From Assumptions
COE - TPI X FCR	6.82	cents/kWh	
COE - AO&M	4.07	cents/kWh	
COE - LO&R	0.44	cents/kWh	
COE	$0.1133	$/kWh	Calculated
COE	**11.33**	cents/kWh	Calculated

Appendix D Com'l Plant Economics WS – NUG – Avoided Cost– With PTC

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 including insurance
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

SHEET 1 - TOTAL PLANT COST (TPC) - 2004$

TPC Component	Unit	Unit Cost	Total Cost (2004$)	Notes and Assumptions
Procurement				
Onshore Trans & Grid I/C	1	$3,084,000	$3,084,000	
Subsea Cables	1	$3,950,000	$3,950,000	
Mooring	180	$137,222	$24,699,960	
Power Conversion Modules (set of 3)	180	$623,961	$112,312,980	
Concrete Structure Sections	180	$244,800	$44,064,000	
Facilities	1	$12,000,000	$12,000,000	
Installation	1	$11,229,000	$11,229,000	
Construction Management (5%)	1	$10,566,997	$10,566,997	
TOTAL			$221,906,937	

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	$110,953,469	$8,876,277	$8,018,318	$118,971,786
2007	$110,953,469	$17,752,555	$14,486,572	$125,440,040
Total	$221,906,937	$26,628,832	$22,504,889	$244,411,826

SHEET 2 - ANNUAL OPERATING AND MAINTENANCE COST 2004$

Costs	Yrly Cost	Amount
LABOR	$2,322,000	$2,322,000
PARTS AND SUPPLIES	$4,941,000	$4,941,000
INSURANCE	$4,941,000	$4,941,000
Total		$12,204,000

SHEET 3 - OVERHAUL AND REPLACEMENT COST (LOAR)

O&R Costs	Year of Cost	Cost in 2004$	Cost Inflated to 2018$
10 Year Retrofit			
Operation	10	$9,758,000	$14,759,851
Parts	10	$16,804,000	$25,417,558
Total	10	$26,562,000	$40,177,408

SHEET 4 - 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	Hawaii	
6	State Tax Rate	6.4	%
	Composite Tax Rate (t)	0.3916	%
	t/(1-t)	0.6437	
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	8.51	%
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	0	% 1st year only % of TPI up to $2.5M
19	State Production Tax Credit	0	
20	Avoided cost electricity price - 2002$	0.0841	$/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	

SHEET 5 - INCOME STATEMENT ($) **CURRENT DOLLARS**

Description/Year	2008	2009	2010	2011	2012	2013	2014	2015
REVENUES								
Energy Payments	27,715,864	28,547,340	29,403,760	30,285,873	31,288,033	32,323,354	33,392,934	34,497,906
State ITC and PTC	0							
Federal ITC and PTC	29,841,183	5,400,000	5,400,000	5,400,000	5,400,000	5,400,000	5,400,000	5,400,000
TOTAL REVENUES	57,557,047	33,947,340	34,803,760	35,685,873	36,688,033	37,723,354	38,792,934	39,897,906
AVG $/KWH	0.192	0.113	0.116	0.119	0.122	0.126	0.129	0.133
OPERATING COSTS								
Scheduled and Unscheduled O&M	13,735,710	14,147,781	14,572,214	15,009,381	15,459,662	15,923,452	16,401,155	16,893,190
Scheduled O&R	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0
TOTAL	13,735,710	14,147,781	14,572,214	15,009,381	15,459,662	15,923,452	16,401,155	16,893,190
EBITDA	43,821,337	19,799,559	20,231,546	20,676,493	21,228,371	21,799,902	22,391,778	23,004,716
Tax Depreciation	48,882,365	78,211,784	46,927,071	28,156,242	28,156,242	14,078,121	0	0
Interest Pald	13,687,062	13,387,970	13,064,950	12,716,088	12,339,318	11,932,406	11,492,941	11,018,318
TAXABLE EARNINGS	-18,748,090	-71,800,195	-39,760,474	-20,195,838	-19,267,189	-4,210,625	10,898,837	11,986,397
State Tax	-1,199,878	-4,595,212	-2,544,670	-1,292,534	-1,233,100	-269,480	697,526	767,129
Federal Tax	-6,141,874	-23,521,744	-13,025,531	-6,616,157	-6,311,931	-1,379,401	3,570,459	3,926,744
TOTAL TAX OBLIGATIONS	-7,341,752	-28,116,956	-15,570,202	-7,908,690	-7,545,031	-1,648,881	4,267,985	4,693,873

Description/Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Energy Payments	35,639,441	36,818,751	38,037,083	39,295,730	40,596,026	41,939,348	43,327,121	44,760,816	46,241,951	47,772,097	47,772,097	49,352,876
State ITC and PTC												
Federal ITC and PTC	5,400,000	5,400,000										
TOTAL REVENUES	41,039,441	42,218,751	38,037,083	39,295,730	40,596,026	41,939,348	43,327,121	44,760,816	46,241,951	47,772,097	47,772,097	49,352,876
AVG $/KWH	0.137	0.141	0.127	0.131	0.135	0.140	0.144	0.149	0.154	0.159	0.159	0.165
Scheduled and Unscheduled O&M	17,399,986	17,921,985	18,459,645	19,013,434	19,583,837	20,171,353	20,776,493	21,399,788	22,041,782	22,703,035	23,384,126	24,085,650
Scheduled O&R	0	0	60,771,935	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	17,399,986	17,921,985	79,231,580	19,013,434	19,583,837	20,171,353	20,776,493	21,399,788	22,041,782	22,703,035	23,384,126	24,085,650
EBITDA	23,639,456	24,296,765	-41,194,497	20,282,296	21,012,188	21,767,996	22,550,628	23,361,028	24,200,170	25,069,062	24,387,971	25,267,226
Tax Depreciation	0	0	0	0	0	0	0	0	0	0	0	0
Interest Pald	10,505,726	9,952,127	9,354,239	8,708,521	8,011,145	7,257,979	6,444,560	5,566,067	4,617,295	3,592,621	2,485,974	1,290,794
TAXABLE EARNINGS	13,133,729	14,344,638	-50,548,736	11,573,775	13,001,043	14,510,016	16,106,068	17,794,960	19,582,874	21,476,441	21,901,998	23,976,432
State Tax	840,559	918,057	-3,235,119	740,722	832,067	928,641	1,030,788	1,138,877	1,253,304	1,374,492	1,401,728	1,534,492
Federal Tax	4,302,610	4,699,303	-16,559,766	3,791,569	4,259,142	4,753,481	5,276,348	5,829,629	6,415,350	7,035,682	7,175,094	7,854,679
TOTAL TAX OBLIGATIONS	5,143,168	5,617,360	-19,794,885	4,532,290	5,091,208	5,682,122	6,307,136	6,968,507	7,668,654	8,410,174	8,576,822	9,389,171

SHEET 6 - CASH FLOW STATEMENT

Description/Year	2006	2007	2008	2009	2010	2011
EBITDA			43,821,337	19,799,559	20,231,546	20,676,493
Taxes Paid			-7,341,752	-28,116,956	-15,570,202	-7,908,690
CASH FLOW FROM OPS			51,163,090	47,916,516	35,801,748	28,585,183
Debt Service			-17,425,719	-17,425,719	-17,425,719	-17,425,719
NET CASH FLOW AFTER TAX		-73,323,548	33,737,370	30,490,797	18,376,029	11,159,464
CUM NET CASH FLOW		-73,323,548	-39,586,177	-9,095,381	9,280,648	20,440,112
IRR ON NET CASH FLOW AFTER TAX						

2012	2013	2014	2015	2016	2017	2018	2019
21,228,371	21,799,902	22,391,778	23,004,716	23,639,456	24,296,765	-41,194,497	20,282,296
-7,545,031	-1,648,881	4,267,985	4,693,873	5,143,168	5,617,360	-19,794,885	4,532,290
28,773,402	23,448,783	18,123,793	18,310,842	18,496,287	18,679,405	-21,399,612	15,750,006
-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719
11,347,683	6,023,064	698,074	885,123	1,070,568	1,253,686	-38,825,331	-1,675,713
31,787,795	37,810,858	38,508,933	39,394,056	40,464,624	41,718,310	2,892,979	1,217,265

2020	2021	2022	2023	2024	2025	2026	2027
21,012,188	21,767,996	22,550,628	23,361,028	24,200,170	25,069,062	24,387,971	25,267,226
5,091,208	5,682,122	6,307,136	6,968,507	7,668,654	8,410,174	8,576,822	9,389,171
15,920,980	16,085,873	16,243,492	16,392,521	16,531,516	16,658,888	15,811,149	15,878,055
-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719
-1,504,739	-1,339,846	-1,182,227	-1,033,198	-894,203	-766,831	-1,614,570	-1,547,664
-287,474	-1,627,319	-2,809,547	-3,842,744	-4,736,947	-5,503,778	-7,118,348	-8,666,012
							9.6%

Appendix E Com’l Plant Economics WS – NUG – Avoided Cost– Without PTC

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 including insurance
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
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2 Calculates State Investment and Producions 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

SHEET 1 - TOTAL PLANT COST (TPC) - 2004$

TPC Component	Unit	Unit Cost	Total Cost (2004$)	Notes and Assumptions
Procurement				
Onshore Trans & Grid I/C	1	$3,084,000	$3,084,000	
Subsea Cables	1	$3,950,000	$3,950,000	
Mooring	180	$137,222	$24,699,960	
Power Conversion Modules (set of 3)	180	$623,961	$112,312,980	
Concrete Structure Sections	180	$244,800	$44,064,000	
Facilities	1	$12,000,000	$12,000,000	
Installation	1	$11,229,000	$11,229,000	
Construction Management (5%)	1	$10,566,997	$10,566,997	
TOTAL			$221,906,937	

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	$110,953,469	$8,876,277	$8,018,318	$118,971,786
2007	$110,953,469	$17,752,555	$14,486,572	$125,440,040
Total	$221,906,937	$26,628,832	$22,504,889	$244,411,826

SHEET 2 - ANNUAL OPERATING AND MAINTENANCE COST 2004$

Costs	Yrly Cost	Amount
LABOR	$2,322,000	$2,322,000
PARTS AND SUPPLIES	$4,941,000	$4,941,000
INSURANCE	$4,941,000	$4,941,000
Total		$12,204,000

SHEET 3 - OVERHAUL AND REPLACEMENT COST (LOAR)

O&R Costs	Year of Cost	Cost in 2004$	Cost Inflated to 2018$
10 Year Retrofit			
Operation	10	$9,758,000	$14,759,851
Parts	10	$16,804,000	$25,417,558
Total	10	$26,562,000	$40,177,408

SHEET 4 - 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	Hawaii	
6	State Tax Rate	6.2	%
	Composite Tax Rate (t)	0.389	%
	t/(1-t)	0.6367	
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	8.52	%
15	Inflation rate	3	%
16	Federal Investment Tax Credit	10	% 1st year only
17	Federal Production Tax Credit	0	$/kWh for 1st 10 yrs
18	State Investment Tax Credit	0	% 1st year only
			% of TPI up to $2.5M
19	State Production Tax Credit	0	
20	Avoided cost electricity price - 2002$	0.0841	$/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	

SHEET 5 - INCOME STATEMENT ($) **CURRENT DOLLARS**

Description/Year	2008	2009	2010	2011	2012	2013	2014	2015
REVENUES								
Energy Payments	27,715,864	28,547,340	29,403,760	30,285,873	31,288,033	32,323,354	33,392,934	34,497,906
State ITC and PTC	0							
Federal ITC and PTC	24,441,183	0	0	0	0	0	0	0
TOTAL REVENUES	52,157,047	28,547,340	29,403,760	30,285,873	31,288,033	32,323,354	33,392,934	34,497,906
AVG $/KWH	0.174	0.095	0.098	0.101	0.104	0.108	0.111	0.115
OPERATING COSTS								
Scheduled and Unscheduled O&M	13,735,710	14,147,781	14,572,214	15,009,381	15,459,662	15,923,452	16,401,155	16,893,190
Scheduled O&R	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0
TOTAL	13,735,710	14,147,781	14,572,214	15,009,381	15,459,662	15,923,452	16,401,155	16,893,190
EBITDA	38,421,337	14,399,559	14,831,546	15,276,493	15,828,371	16,399,902	16,991,778	17,604,716
Tax Depreciation	48,882,365	78,211,784	46,927,071	28,156,242	28,156,242	14,078,121	0	0
Interest Paid	13,687,062	13,387,970	13,064,950	12,716,088	12,339,318	11,932,406	11,492,941	11,018,318
TAXABLE EARNINGS	-24,148,090	-77,200,195	-45,160,474	-25,595,838	-24,667,189	-9,610,625	5,498,837	6,586,397
State Tax	-1,545,478	-4,940,812	-2,890,270	-1,638,134	-1,578,700	-615,080	351,926	421,529
Federal Tax	-7,910,914	-25,290,784	-14,794,571	-8,385,197	-8,080,971	-3,148,441	1,801,419	2,157,704
TOTAL TAX OBLIGATIONS	-9,456,392	-30,231,596	-17,684,842	-10,023,330	-9,659,671	-3,763,521	2,153,345	2,579,233

Description/Year	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES												
Energy Payments	35,639,441	36,818,751	38,037,083	39,295,730	40,596,026	41,939,348	43,327,121	44,760,816	46,241,951	47,772,097	47,772,097	49,352,876
State ITC and PTC												
Federal ITC and PTC	0	0										
TOTAL REVENUES	35,639,441	36,818,751	38,037,083	39,295,730	40,596,026	41,939,348	43,327,121	44,760,816	46,241,951	47,772,097	47,772,097	49,352,876
AVG $/KWH	0.119	0.123	0.127	0.131	0.135	0.140	0.144	0.149	0.154	0.159	0.159	0.165
OPERATING COSTS												
Scheduled and Unscheduled O&M	17,399,986	17,921,985	18,459,645	19,013,434	19,583,837	20,171,353	20,776,493	21,399,788	22,041,782	22,703,035	23,384,126	24,085,650
Scheduled O&R	0	0	60,771,935	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	17,399,986	17,921,985	79,231,580	19,013,434	19,583,837	20,171,353	20,776,493	21,399,788	22,041,782	22,703,035	23,384,126	24,085,650
EBITDA	18,239,456	18,896,765	-41,194,497	20,282,296	21,012,188	21,767,996	22,550,628	23,361,028	24,200,170	25,069,062	24,387,971	25,267,226
Tax Depreciation	0	0	0	0	0	0	0	0	0	0	0	0
Interest Paid	10,505,726	9,952,127	9,354,239	8,708,521	8,011,145	7,257,979	6,444,560	5,566,067	4,617,295	3,592,621	2,485,974	1,290,794
TAXABLE EARNINGS	7,733,729	8,944,638	-50,548,736	11,573,775	13,001,043	14,510,016	16,106,068	17,794,960	19,582,874	21,476,441	21,901,998	23,976,432
State Tax	494,959	572,457	-3,235,119	740,722	832,067	928,641	1,030,788	1,138,877	1,253,304	1,374,492	1,401,728	1,534,492
Federal Tax	2,533,570	2,930,263	-16,559,766	3,791,569	4,259,142	4,753,481	5,276,348	5,829,629	6,415,350	7,035,682	7,175,094	7,854,679
TOTAL TAX OBLIGATIONS	3,028,528	3,502,720	-19,794,885	4,532,290	5,091,208	5,682,122	6,307,136	6,968,507	7,668,654	8,410,174	8,576,822	9,389,171

SHEET 6 - CASH FLOW STATEMENT

Description/Year	2006	2007	2008	2009	2010	2011
EBITDA			38,421,337	14,399,559	14,831,546	15,276,493
Taxes Paid			-9,456,392	-30,231,596	-17,684,842	-10,023,330
CASH FLOW FROM OPS			47,877,730	44,631,156	32,516,388	25,299,823
Debt Service			-17,425,719	-17,425,719	-17,425,719	-17,425,719
NET CASH FLOW AFTER TAX		-73,323,548	30,452,010	27,205,437	15,090,669	7,874,104
CUM NET CASH FLOW		-73,323,548	-42,871,537	-15,666,101	-575,432	7,298,672
IRR ON NET CASH FLOW AFTER TAX						

Description/Year	2012	2013	2014	2015	2016	2017	2018	2019
EBITDA	15,828,371	16,399,902	16,991,778	17,604,716	18,239,456	18,896,765	-41,194,497	20,282,296
Taxes Paid	-9,659,671	-3,763,521	2,153,345	2,579,233	3,028,528	3,502,720	-19,794,885	4,532,290
CASH FLOW FROM OPS	25,488,042	20,163,423	14,838,433	15,025,482	15,210,927	15,394,045	-21,399,612	15,750,006
Debt Service	-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719
NET CASH FLOW AFTER TAX	8,062,323	2,737,704	-2,587,286	-2,400,237	-2,214,792	-2,031,674	-38,825,331	-1,675,713
CUM NET CASH FLOW	15,360,995	18,098,698	15,511,413	13,111,176	10,896,384	8,864,710	-29,960,621	-31,636,335

Description/Year	2020	2021	2022	2023	2024	2025	2026	2027
EBITDA	21,012,188	21,767,996	22,550,628	23,361,028	24,200,170	25,069,062	24,387,971	25,267,226
Taxes Paid	5,091,208	5,682,122	6,307,136	6,968,507	7,668,654	8,410,174	8,576,822	9,389,171
CASH FLOW FROM OPS	15,920,980	16,085,873	16,243,492	16,392,521	16,531,516	16,658,888	15,811,149	15,878,055
Debt Service	-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719	-17,425,719
NET CASH FLOW AFTER TAX	-1,504,739	-1,339,846	-1,182,227	-1,033,198	-894,203	-766,831	-1,614,570	-1,547,664
CUM NET CASH FLOW	-33,141,074	-34,480,919	-35,663,147	-36,696,344	-37,590,547	-38,357,378	-39,971,948	-41,519,612
IRR ON NET CASH FLOW AFTER TAX								#NUM!

Appendix F Cost Estimate of Transmission Line Upgrade for Commercial Plant

The Waimanalo Beach substation is connected by a 46 kV link to the Koolau substation and the Oahu grid. In order to accommodate the additional 90 MW maximum rating of the commercial offshore power plant, a build out of the stretch of the Waimanalo Beach-Koolau is needed.

Rough cost estimates for one (1) Waimanalo Beach-Koolau 138 kV line(8.4 miles long) were provided by HECO:

- $28 million if overhead
- $146 million if underground (XLPE cables).

The costs are in 2009 base dollars. The estimates include an estimate of the substation costs, but do not include any land costs (which are unknown at this point).

Note

Provision of the above estimates does not mean the above line represents sufficient transmission to interconnect the generating facility. The transmission requirements are unknown at this point as no interconnection analysis was performed. Nor do the above estimates imply that such a line, overhead or underground, can be constructed per the assumptions that went into the rough estimates as no design analysis was performed. Also, there may be other factors that may have significant costs, but will not be accurately quantifiable until such time the project is better defined and/or implemented. Such factors may include extensive community and governmental relations efforts, legal/litigation issues, environmental issues, and regulatory issues. The above estimates are nothing more than just rough estimates of what it might cost to build a Waimanalo Beach-Koolau 138 kV line.