Economics of Ocean Thermal Energy Conversion (OTEC)

by

Luis A. Vega, Ph.D.

Published by the American Society of Civil Engineers (ASCE)

Chapter 7 of
"Ocean Energy Recovery: The State of the Art"
1992

Published in Ocean Energy Recovery, pp 152-181, ASCE (1992)

Table of Contents

Figures

Tables

Published in Ocean Energy Recovery, pp 152-181, ASCE (1992)

7: Economics of Ocean Thermal Energy Conversion (OTEC)

Luis A. Vega, Ph.D.[1, 2]

Abstract

A straightforward analytical model is proposed to compare the cost of electricity produced either with OTEC or with petroleum or coal-fired plants. In the case of OTEC, when appropriate, the cost of electricity is estimated with credit for the desalinated water produced. The production cost of OTEC products are levelized over the life of the plant (nominal value: 30 years). Two generalized markets are considered: industrialized nations and smaller, less-developed island nations with modest needs. The model is used to establish scenarios under which OTEC could be competitive.

The scenarios are defined by two parameters: fuel cost, and the cost of fresh water production. In the absence of natural sources of fresh water, it is postulated that the cost of producing desalinated water from seawater via reverse osmosis (RO) be considered as the conventional technique. This approach yields a direct relationship between desalinated water production and fuel cost; and therefore, a scenario defined with one parameter.

It is determined that OTEC should only be considered as a system to produce electricity and desalinated water, because OTEC–based, mariculture operations and air–conditioning systems can only make use of a small amount of the seawater available; and therefore, could only impact small plants. The use of energy carriers (e.g.: Hydrogen, Ammonia) to transport OTEC energy generated in floating plants, drifting in tropical waters away from land, is determined to be technically feasible but requires increases in the cost of fossil fuels of at least an order of magnitude to be cost effective.

It is postulated that OTEC plants will be limited, by the relatively large diameter required for cold water pipes, to sizes of no more than 100 MWe–net (10 m diameter) in the case of floating plants and somewhat less (the value is a function of bathymetry or pipe length) for land-based plants. Furthermore, in the case of open cycle the plants will be limited by the low pressure turbine to 2.5 MWe-net modules or, for example, 10 MWe-net plants (arbitrarily, setting at four the number of modules per plant). Although the future rests in relatively large closed cycle OTEC floating plants, given the low level funding available for development of alternative energy, the first commercial plants will have to be 1 to 10 MWe land-based plants designed for the less-developed islands and funded by international aid agencies. The analysis shows that these, first generation, plants will have to produce electricity and desalinated water to offset the relatively higher cost of electricity; and, that their commercialization should be preceded by the

---

[1] Pacific International Center for High Technology Research(PICHTR).

[2] The views expressed in this chapter are those of the author and do not necessarily represent those of PICHTR.

installation of a demonstration plant of at least 1 MWe and 1,700 m^3 to 3,500 m^3, of desalinated water, per day production capacity. This demonstration plant would be used to obtain operational information and optimize the design of the first generation of commercial plants.

It is determined that plants of at least 50 MWe capacity would be required for the industrialized nations; and, that if desalinated water is required to reach wider scenarios, it is proposed that a hybrid plant be used, based on the closed cycle for the electricity production and a second-stage, for desalinated water production, consisting of a flash (vacuum) evaporator and surface condenser. Closed cycle plants, without second-stage desalinated water production, are found to be cost effective if housed in floating vessels, moored or dynamically positioned a few kilometers from land, transmitting the electricity to shore via submarine power cables. The moored vessel could also house a hybrid OTEC plant and transport the desalinated water produced via flexible pipes. It is recommended that a floating 5 MWe and 7,500 m^3/day demonstration plant be designed, installed and operated prior to the commercialization of plants of at least 50 MWe capacity.

Background

The search for renewable sources of energy has resulted in the revival of a concept based on the utilization of the differences in temperature, ΔT, between the warm ($T_W \sim$ 22°C to 29°C) tropical surface waters, and the cold ($T_C \sim$ 4°C to 5°C) deep ocean waters available at depths of about 1,000 m, as the source of the thermal energy required to vaporize and condense the working fluid of a turbine-generator system. This concept is referred to as Ocean Thermal Energy Conversion (OTEC).

There are two approaches to the extraction of thermal energy from the oceans, one referred to as "closed cycle" and the other as "open cycle." These approaches are described in Chapters 6 and 7 respectively, and briefly summarized here as an introduction to the analysis that follows. In the closed cycle, seawater is used to vaporize and condense a working fluid, such as ammonia, which drives a turbine-generator in a closed loop, producing electricity. In the open cycle, surface water is flash-evaporated in a vacuum chamber. The resulting low-pressure steam is used to drive a turbine-generator. Cold seawater is used to condense the steam after it has passed through the turbine. The open cycle can, therefore, be configured to produce fresh water as well as electricity.

The closed cycle was first proposed in 1881, by D'Arsonval in France, and was demonstrated in 1979, when a small plant mounted on a barge off Hawaii (Mini-OTEC) produced 50 kW of gross power, for several months, with a net output of 18 kW. This closed cycle plant was sponsored by private industry and the State of Hawaii. Subsequently, a 100 kW gross power, land-based plant was operated in the island nation of Nauru by a consortium of companies sponsored by the Japanese government. These plants were designed with public relations as the main objective and minimal operational data was obtained.

The open cycle concept was first proposed in the 1920's and demonstrated in 1930, off Cuba by its inventor, a Frenchman by the name of Georges Claude. His land–

based demonstration plant was designed to resolve some of the ocean engineering issues common to all OTEC plants and, hopefully, to produce net electricity. This plant made use of a direct contact condenser; therefore, fresh water was not a by-product. The plant failed to achieve net power production because of a poor site selection (e.g., thermal resource) and a mismatch of the power and seawater systems; however, the plant did operate for several weeks.

An OTEC hybrid cycle, wherein electricity is produced in a first-stage (closed cycle) followed by water production in a second-stage, has been proposed as a means to maximize the use of the thermal resource available and produce water and electricity (Nihous, Syed and Vega, 1989). In the second-stage, the temperature difference available in the seawater effluents from an OTEC plant (e.g.: 12°C) is used to produce desalinated water through a system consisting of a flash evaporator and a surface condenser (basically, an open cycle without a turbine-generator). In the case of an open cycle plant, the addition of a second-stage results in doubling water production. Fresh water production with a flash-evaporator and surface condenser system was demonstrated in 1988 in a facility built by the U.S. Department of Energy at the Natural Energy Laboratory of Hawaii (NELH).

Floating vessels, approaching the dimensions of supertankers, housing factories operated with OTEC-generated electricity or transmitting the electricity to shore via submarine power cables have been conceptualized. Large diameter pipes suspended from these plantships extending to depths of 1,000 m are required to transport the deep ocean water to the heat exchangers onboard. The design and operation of these cold water pipes is a major issue that has been resolved (Vega and Nihous, 1988).

The proof-of-concept projects (i.e., Mini-OTEC, Nauru, Claude) demonstrated that both cycles are technically feasible and only limited, by the large diameters required for the cold water pipes, to sizes of no more than about 100 MWe (Vega, Nihous, Lewis, Resnick and Van Ryzin, 1989). In the case of the open cycle, due to the low-pressure steam, the turbine is presently limited to sizes of no more than 2.5 MWe.

Industry has not taken advantage of this information because, at present, the price of oil fuels and coal are such that conventional power plants produce cost-effective electricity. Moreover, the power industry can only invest in power plants whose design is based on similar plants with an operational record. Before OTEC can be commercialized, a prototypical plant must be built and operated to obtain the information required to design commercial systems and to gain the confidence of the financial community and industry. Conventional power plants pollute the environment more than an OTEC plant would and the fuel for OTEC is unlimited and free, as long as the sun heats the oceans; however, it is futile to use these arguments to convince the financial community to invest in an OTEC plant unless it has a proven operational record.

Site Selection Criteria for OTEC Plants [3]

Except for closed basins, such as the Mediterranean and Red Seas, deep seawater flows from the polar regions: polar water, which represents up to 60% of all seawater, originates mainly from the Arctic for the Atlantic and North Pacific Oceans, and from the Antarctic (Weddell Sea) for all other major oceans. Therefore, T_C at a given depth, approximately below 500 m, does not vary much throughout all regions of interest for OTEC. It is also a weak function of depth, with a typical gradient of 1°C per 150 m between 500 m and 1000 m. These considerations may lead to regard T_C as nearly constant, with a value of 4°C at 1000 m.

Two facts require caution, however, during the OTEC site selection process:
1) OTEC is very sensitive to any loss of thermal resource, and 2) the Cold Water Pipe is a costly plant component. Consequently, variations in T_C that appear to be small may have a drastic impact on the performance and/or the capital cost of the OTEC plant. For example, Pacific Ocean deep (1000 m) water at low latitudes is colder by about 1°C than Atlantic Ocean deep water; in the case of the East Coast of Africa, various phenomena including mixing with Red Sea outflow elevate the Indian Ocean water temperature (at 1000 m depth) to more than 6°C. As for the optimal depth at a given land-based OTEC site, seafloor bathymetry and topography play an important role and some degree of thermo-economic optimization is required; this point is discussed in more details in Nihous, Syed and Vega (1989), and Nihous, Udui and Vega (1989).

The other component of ΔT is T_W, the surface seawater temperature. In view of the above discussion regarding T_C, a desirable OTEC thermal resource of at least 20°C requires typical values of T_W of the order of 25°C. Globally speaking, regions between latitudes 20°N and 20°S are adequate. Some definite exceptions exist due to strong cold currents: along the West Coast of South America, tropical coastal water temperatures remain below 20°C, and are often of the order of 15°C; a similar situation prevails to a lesser extent for the West Coast of Southern Africa. Moreover, T_W varies throughout the year, and sometimes exhibits a significant seasonal drop due to the upwelling of deeper water induced by the action of the wind: such are the cases of the West Coast of Northern Africa in the Winter, where temperatures T_W as low as 17°C are observed. More localized upwelling may occur, such as near the Horn of Africa in August, and in general, a careful OTEC site selection requires a comprehensive knowledge of local climate features inasmuch as they may affect T_W seasonally.

The following summarizes the availability of the OTEC thermal resource throughout the World:

- Equatorial waters, defined as lying between 10°N and 10°S are adequate except for the West Coast of South America; significant seasonal temperature enhancement (e.g., with solar ponds) would be required on the West Coast of Southern Africa; moreover, deep water temperature is warmer by about 2°C along the East Coast of Africa.

[3] This section was written by Dr. G.C. Nihous.

- Tropical waters, defined as extending from the equatorial region boundary to, respectively, 20°N and 20°S, are adequate, except for the West Coasts of South America and of Southern Africa; moreover, seasonal upwelling phenomena would require significant temperature enhancement for the West Coast of Northern Africa, the Horn of Africa, and off the Arabian Peninsula.

The accessibility of deep cold seawater represents the most important physical criterion for OTEC site selection, once the existence of an adequate thermal resource has been established. Naturally, the distance from shoreline where water depths of the order of 1000 m may be found is far more critical for <u>land-based</u> plants than for floating plants, since it determines the length of the costly cold water pipe; in the case of a floating plant, the issue of cold seawater accessibility is only relevant inasmuch as a power cable, and, maybe, a small fresh water pipe, are needed to "export" the OTEC products to shore.

A valid way to assess cold seawater accessibility is to use a simple rule of thumb derived from the bathymetry of some of the potential OTEC sites in the World, namely that the 1000 m contour depth lie within 3000 m from shoreline. It should be emphasized that a study by Nihous, Udui and Vega (1989) demonstrated that the sensitivity of the OTEC production cost of electricity to detailed seafloor bathymetry is mostly pronounced for smaller plant sizes (1 to 10 MWe net power); for larger plants, a considerable economy of scale for OTEC seawater systems greatly reduces the importance of average seafloor slope.

The West Coast of Northern Africa or the East Coast of Africa, fall into the category of sites where warm water enhancement would be highly desirable because of a relatively adverse seafloor bathymetry (aside from the occurrence of a seasonal upwelling in the former case). The case of Australia is even worse: this country consists of a tectonic plate that extends far offshore, e.g., to the Great Barrier Reef, on its Northern tropical side. The Arabian Peninsula is also bordered by waters too shallow for OTEC to be practical.

Thus, physical factors affecting OTEC site selection, i.e., thermal resource and seafloor bathymetry, greatly restrict the number of desirable sites along the shoreline of major continents, unless some warm seawater temperature enhancement is possible. Most of the best, land-based, OTEC sites consist of island locations.

Finally, shoreline and hinterland topography, or extended shallow coral reefs require special attention. In the latter case, strong environmental concerns may not allow the building of any structure on the reef itself, although it represents a natural barrier against large breaking waves. Moreover, certain apparently favorable OTEC sites may be flanked by precipitous cliffs, or their hinterland may be very limited by rising mountain slopes.

The severe constraint of a favorable bathymetric profile, for the practical implementation of land-based OTEC technologies, would be relaxed to a considerable extent if the notion of floating OTEC plants were revived. In fact, the potential benefits of OTEC could only be recovered on a large scale through the development of an ambitious floating-plant program, following the initial experimental land-based OTEC phase.

Many other points must be considered when evaluating potential OTEC sites, from logistics to socioeconomic and political factors. One argument in favor of OTEC lies in its renewable character: it may be seen as a means to provide remote and isolated communities with some degree of energy independence, and to offer them a potential for safe economic development. Paradoxically, however, such operational advantages are often accompanied by serious logistical problems during the plant construction and installation phases: if an island is under development, it is likely to lack the infrastructure desirable for this type of project, including harbors, airports, good roads and communication systems.

Moreover, the population base should be compatible with the OTEC plant size: adequate manpower must be supplied to operate the plant; and, the electricity and fresh water plant outputs should match local consumption in orders of magnitude. 1 to 10 MWe plants would generally suffice in most small Pacific islands (e.g., see IFREMER, 1985), whereas in the case of a populous and industrialized country like Taiwan, the largest feasible OTEC plants, up to 100 MWe, could be eventually considered (Shyu, 1989).

Since environmental protection has been recognized as a global issue, another important point to consider is the preservation of the environment in the area of the selected site, inasmuch as preservation of the environment anywhere is bound to have positive effects elsewhere. OTEC definitely offers one of the most benign power production technology, since the handling of hazardous substances is limited to the working fluid (e.g.: ammonia), and no noxious by-products are generated; OTEC merely requires the pumping and discharge of various seawater masses, which, according to preliminary studies, can be accomplished with virtually no adverse impact. This argument should be very attractive, for pristine island ecosystems, as well as for already polluted and overburdened environments. For example, the amount of CO_2 released from electricity-producing plants (expressed in gr of CO_2 per kWh) ranges from 1,000, for coal fired plants, to 700, for fuel-oil plants, while for closed cycle OTEC plants the value is less than 12 and for open cycle as much as 40 (Green and Guenther, 1989; Vega, 1981).

One major difficulty with OTEC is not of a technological order: OTEC is capital-intensive, and the very first plants, mainly because of their small size, will require a substantial capital investment. Given the prevailing low cost of crude oil and of fossil fuels in general, the development of OTEC technologies is likely to be promoted by government agencies rather than by private industry. The motivation of governments in subsidizing OTEC may vary greatly, from foreign aid to domestic concerns.

For the former case, ideal recipient countries are likely to be independent developing nations. If these countries' economic standing is too low, however, the installation of an OTEC plant rather than direct aid in the form of money and goods may be perceived as inadequate help. In addition, political instability could jeopardize the good will of helping nations to invest.

For the latter case, potential sites belong to, or fall within the jurisdiction of, developed countries. A study performed by Dunbar (1981) identified ninety-eight nations and territories with access to the OTEC thermal resource (20° C temperature difference between surface water and deep ocean water) within their 200 nautical mile exclusive economic zone (EEZ). For the majority of these locations, the OTEC resource is applicable only to floating plants (arbitrarily assuming that the length of the cold water pipe for a land-based plant should not exceed 3,000 meters).

Dunbar's study, performed for the U.S. State Department, postulated a significant market potential for OTEC (i.e., 577,000 MWe of new baseload electric power facilities). Unfortunately, now as then, there is no OTEC plant with an operational record available. This still remains the impediment to OTEC commercialization.

The following list of potential sites is reproduced from Dunbar (1981):

GEOGRAPHICAL AREA	MAINLAND		ISLAND	
AMERICAS	Mexico	Guyana	Cuba	Guadeloupe (FR)
	Brazil	Suriname	Haiti	Martinique (FR)
	Colombia	French Guiana (FR)	Dominican Rep.	Barbados
	Costa Rica	Nicaragua	Jamaica	Dominica
	Guatemala	El Salvador	Virgin Is. (US)	St. Lucia
	Honduras	Belize	Grenada	St. Kitts (UK)
	Panama	United States	St. Vincent	Barbuda (UK)
	Venezuela		Grand Cayman (UK)	Montserrat (UK)
			Antigua (UK)	The Grenadines (UK)
			Puerto Rico (US)	Curacao (NETH)
			Trinidad & Tobago	Aruba (NETH)
			Bahamas	
AFRICA	Nigeria	Gabon	Sao Tome & Principe	
	Ghana	Benin	Ascension (UK)	
	Ivory Coast	Zaire	Comoros	
	Kenya	Angola	Aldabra (UK)	
	Tanzania	Cameroon	Madagascar	
	Congo	Mozambique		
	Guinea	Eq. Guinea		
	Sierra Leone	Togo		
	Liberia	Somalia		
INDIAN/PACIFIC OCEAN	India	Australia	Indonesia	American Samoa (US)
	Burma	Japan	Philippines	Trust Territories (US)
	China	Thailand	Sri Lanka	Northern Marianas
	Vietnam	Hong Kong (UK)	Papua New Guinea	Guam (US)
	Bangladesh	Brunei	Taiwan	Kiribati
	Malaysia		Fiji	French Polynesia (FR)
			Nauru	New Caledonia (FR)
			Seychelles	Diego Garcia
			Maldives	Tuvalu
			New Hebrides (UK/FR)	Wake Is. (US)
			Samoa	Solomon Is.
			Tonga	Mauritius
			Cook Is.	Okinawa (JAPAN)
			Wallis & Futuna Is. (FR)	
			Hawaii	

OTEC Potential Market

There are at least two distinct markets for OTEC: (i) industrialized nations and islands; and, (ii) smaller or less industrialized islands with modest needs for power and fresh water.

The following global indicators are useful in relating the size of the plants considered herein with the needs of a community: (1) domestic water needs in developed nations are met with 100 gallons (˜ 400 liters) per person per day [the United Nations uses a figure of 50 gallons (˜ 200 liters) for countries under development]; in agricultural regions the use is 7 to 10 times larger; (2) the electrical power needs (domestic and industrial) of each 1,000 to 2,000 people are met with 1 MW in industrialized nations, while in less developed countries (LDCs) the needs of 5 to 15 times more people are met with 1 MW.

The small OC-OTEC plants considered in this chapter could be sized to produce from 1 to 10 MW electricity, and at least 450 thousand to 9.2 million gallons of fresh water per day (1,700 to 35,000 m^3/day). That is, the needs of LDCs communities with populations ranging from 4,500 to as much as 100,000 could be met. This range encompasses the majority of less developed island nations throughout the world.

The larger CC-OTEC or hybrid cycle plants can be used in either market for producing electricity and water. For example, a 50 MW hybrid cycle plant producing as much as 16.4 million gallons of water per day (62,000 m^3/day) could be tailored to support a LDC community of approximately 300,000 people or as many as 100,000 people in an industrialized nation. It is interesting to note that the state of Hawaii could be independent, of conventional fuels for the production of electricity, by utilizing the largest floating OTEC plants (50 to 100 MWe-net) for the larger communities in Oahu (˜ 800,000 residents), Kauai, Maui and the Island of Hawaii (˜ 100,000 residents), as well as smaller plants satisfying the needs of Molokai (˜ 8,000 residents). Taiwan (ROC) could use several plants to meet additional requirements projected for the near future. The majority of the nations listed in the previous section could meet all their electricity and water requirements with OTEC.

To assess scenarios under which OTEC might be competitive with conventional technologies, in the production of electricity and water, a straightforward analytical model is developed. First, the capital cost for OTEC plants, expressed in 1990 $/kWe, is established assuming modest engineering development. The relative cost of producing electricity ($/kWh) with OTEC, offset by the desalinated water production, is then equated to the fuel cost of electricity produced with conventional techniques to determine the scenarios (i.e., fuel cost and cost of fresh water production) under which OTEC could be competitive. Inherent to this approach is the assumption that operation and maintenance costs are the same for OTEC and conventional plants of the same power capacity. No attempt is made at speculating about the future cost of fuel. It is simply stated that if a situation is represented by one of our scenarios, OTEC would be competitive.

For each scenario obtained, the cost of desalinated water produced from seawater by reverse osmosis (RO) is also given because this cost must be greater than the water production credit that OTEC requires to be cost effective. Once the cost effective scenarios are established, under this straightforward approach, a more rigorous economic analysis could be performed to model expected inflation and levelized costs (or alternatively, present worth). However, at this stage of development the approach followed here should suffice.

OTEC Capital Cost Estimates and Production Rates

The range of capital costs for single stage OTEC systems is given in Figure 1 for land-based plants rated at nominal values of 1, 10, 50 MWe and 50 and 100 MWe plantships. The economy of scale is obvious. All published estimates for closed or open cycle land–based plants, given in 1990 dollars, fall within the range bounded by the two lines (e.g.: Electric Power Research Institute, 1986; IFREMER, 1985; Nihous et al, 1989; Shyu, 1989; Vega et al, 1989; SERI, Appendix D, 1990). The apparent change in slope at 10 MWe is caused by the use of only three plant sizes and should not be assigned any scale significance; however, it is a convenient way to indicate the upper limit recommended for open cycle plants. At the present level of development, the cost differential between cycles is within the accuracy of the estimates (± 20%). However, while closed cycle should only be limited by the practical size of the cold water pipe (= 10 m) to plants rated at = 100 MWe for floating plants, and somewhat less for land-based plants; open cycle will be limited by the low pressure turbine to 10 MWe plants, consisting of four 2.5 MWe modules. In the case of plantships or floating plants only the costs projected, by the year 2000, for closed cycle plants (Tables 8a and 8b) are shown.

The upper line also represents the present cost estimates with the lower line corresponding to the costs projected by the year 2000 after engineering development and the operation of demonstration plants that are scaled versions of the future commercial plants. These costs, in 1990 dollars are given in Tables 5, 6, 7 and 8a & 8b. The basis for the projected cost reductions are indicated in the tables. For example, work currently underway at ALCAN/MARCONI (e.g.: Johnson, 1989) complemented with the work previously performed by researchers from the Argonne National Laboratory (e.g.: SERI, Appendix D, 1990) indicates that the cost of surface condensers for open cycle, or the second-stage water production unit, and both the evaporator and condenser for the closed cycle should decrease from ˜ $215/m^2 to $100/m^2. All other cost reductions indicated in the tables should result from the operations of the demonstration plants. Future capital costs, corresponding to the lower line in Figure 1, are used throughout the discussion that follows.

Table 1 gives the estimates for 1 MW-net (nominal) open cycle plants with and without second-stage desalinated water production as well as a plant with a system including the use of 90 kg/s of 6°C cold seawater as the chiller fluid for a standard air-conditioning unit supporting a 300 ton load (˜ 300 rooms). For the purpose of this discussion, the 240 kWe of electricity displaced are considered as additional production, resulting in a total production of 10.1 x 10^6 kWh and an adjusted equivalent capital cost of 20,000 $/kW–net. The cost figures are expressed in 1990 dollars. These plants would be designed utilizing the state-of-the-art, bottom-mounted cold water pipe technology (i.e., 1.6 m diameter, high-density, polyethylene pipe). It is assumed that the 1 MW plants could be deployed some time after 1995. Their commercialization must be preceded by the installation of a demonstration plant of 1 MWe and 4,000 m^3, of desalinated water, per day production capacity.

Capital costs and production rates for land-based plants are summarized in Tables 2 and 3 for 10 MW open cycle plants, considered, at present, to be the maximum size for this cycle, and 50 MW closed cycle or, if water production is marketable, hybrid cycle plants. The design of the 10 MW open cycle plant would be scaled from the 1 MW demonstration plant with a new design for bottom-mounted cold water pipes (e.g., see Vega, Nihous, Lewis, Resnick and Van Ryzin, 1989). The commercialization of the 50 MW plants must be preceded by the design and operation of a 5 MWe closed cycle demonstration plant. These land-based plants would require the development of new bottom-mounted cold water pipes.

To consider the 50 MWe OTEC plantship moored or dynamically positioned 10 km offshore, in the discussions that follow, a capital cost of 4,600 \$/kW-net is estimated (Table 8a) for an electrical production of 380 x 10^6 kWh (higher than for the land-based plants because of lower pumping power requirements). This cost is also given in 1990 dollars for a system to be deployed by the Years 2000 to 2005 assuming modest engineering development. These plants would be designed utilizing the methodology already available for cold water pipes suspended from a vessel (Vega and Nihous, 1988). The capital cost for the 100 MWe plant, corresponding to a 10 m diameter cold water pipe, would be 4,200 \$/kW-net with an electrical production of 700 x 10^6 kWh. The capital costs as a function of offshore distance are given in Table 8b.

Conventional Production of Electricity

The thermal efficiency (η) of conventional steam power plants, fired with oil or coal, ranges from 32% to 34% and has been reported to be as high as 36%. The higher value will be assumed in this report. This implies that 36% of the heat added is converted to net work. Net work is defined as the difference between the output from the turbine-generator and the work required to run the plant.

The cycle efficiency for diesel fuel power plants used in Pacific Islands probably ranges from 25% up to 35%. A properly maintained and operated plant can reach efficiencies of up to 36%. This value will be assumed here to determine the work available from the heat added by the diesel fuel. This value is higher than realized in small steam power plants used for generation of electric power only. However, the cost of fuel suitable for the diesel generator is higher than the fuel suitable for the steam plant. Due to fuel availability, most island nations with small electricity requirements (a few MW) utilize diesel generators.

The convention followed in power plant technology to express plant performance is to consider the heat added to produce a unit amount of net work. This parameter is called the heat rate (HR) of the plant and is usually given in Btu/kWh. Therefore, the heat rate is inversely proportional to the thermal efficiency, $\eta = 3413/HR$ (i.e., 1 kWh = 3413 Btu at 60°F), such that a thermal efficiency of 36% corresponds to a HR of 9500 Btu/kWh. [Herein common usage dictates the use of mixed units.]

The heating values of standard coal and fuel oil are 12,000 x (1 ± 0.17) Btu/lbm and 144,000 x (1 ± 0.04) Btu/U.S. gallon, respectively. Therefore, the fuel cost incurred in producing electricity, expressed in \$/kWh, with an oil-fired plant is (within 6%): 1.6 x 10^{-3} times CB, the cost of a barrel (42 U.S. gallons) of fuel [9500 Btu/kWh/ (42 gallons/barrel x 144,000 Btu/gallon) = 0.0016 barrel/ kWh]. Therefore, at \$18 per barrel, the fuel cost is 0.0288 \$/kWh. The same expression will be used for diesel generators.

The 180 MW coal-fired plant under construction in Hawaii (Oahu) can be used to determine the capital cost for conventional steam power plants and the equivalent cost of coal. The plant will use Indonesian coal, with a baseline heat value of 12,500 Btu/lbm, to be delivered to for \$2.25 per million Btu (\$62 per metric ton) such that the fuel cost incurred in producing electricity with a thermal efficiency of 36% would be 0.021 \$/kWh [9500 Btu/kWh x \$2.25 / 10^6 Btu]. This is equivalent to oil fuel cost of \$13/barrel. The electric output will be sold to Hawaiian Electric Company under a 30-year contract. The total capital cost of the project has been estimated to be \$383.5 million; or \$2,100/kW (AES Corporation, 1990).

Conventional Production of Desalinated Water

The cost of producing fresh water from conventional desalination plants (i.e., Reverse Osmosis and Multistage Flash) ranges from about 1.3 to 2 \$/m^3 for a plant capacity of 4,000 m^3/day to approximately 1 \$/m^3 for a 40,000 m^3/day plant.

The energy (cost) used in multistage flash (MSF) distillation is in the form of heat, usually as low pressure steam, and the shaft power to drive pumps and other auxiliaries. Reverse osmosis (RO) plants require energy solely as shaft power from, for example, an electric motor. At present, RO is considered the technique of choice. It can be shown that, fresh water production by RO from seawater costs 0.049.CB, in \$/m^3, where CB is the cost of a barrel (42 gallons) of fuel. This expression is used here to establish the desalinated water cost corresponding to a given fuel cost scenario.

OTEC Production of Electricity

The following formula, proposed by the Electric Power Research Institute, is used to calculate the production cost of electricity p levelized over the assumed life for the OTEC plant (nominal value: 30 years):

$$p\ (\$/\text{kWh}) = (FC \times CC + OM \times G \times CR) / (NP \times CF \times 8760)$$

FC	:	annual fixed charge, taken as 0.10 (e.g.: government loan)
CC	:	plant overall investment capital cost, in \$
OM	:	operation and maintenance yearly \$ expenditures
G	:	present worth factor, in years, estimated value 20
CR	:	capital recovery factor, taken as 0.09
NP	:	net power production, in kW
CF	:	production capacity factor, chosen as 0.80
8760	:	number of hours in one year (CF.8760 =7,008)

The first term simply represents the payment for a fixed interest loan valued at CC, \$, over a prescribed term expressed in hourly payments, where, the loan is for a plant rated at a power of NP, kW. The second term models the levelized cost of operating and maintaining the plant over the term.

For closed cycle plants, p is estimated with no credit taken for the sale of the fresh water by-product. For open or hybrid cycle plants, fresh water credit is obtained by multiplying the unit price by the yearly production and subtracting the result from the numerator of the expression given above. For the sake of completeness, costs estimated in this fashion are given in Tables 9 and 10 for unit prices of water at 0.4 $\$/m^3$ and 0.8 $\$/m^3$ respectively with the O&M expressed as a percentage of capital. It would be appropriate to levelize both the O&M and the unit cost of water (equivalent to multiplying these parameters by 1.8: the product of the capital recovery factor and the present worth factor as given above); however, in the case of prevailing unit price of water (0.4 $\$/m^3$), the unlevelized costs given in Table 9 are within 10% of the levelized costs. In the case of the higher unit price of water (Table 10) levelizing both the O&M and the cost of water produces a dramatic difference. For example, in the case of the 1 MW with second stage, the cost is reduced from 0.25 to 0.19 $/kWh and for the 10MW with second stage results in a reduction from 0.08 $/kWh to less than zero. This is equivalent to a scenario of extremely high production costs for fresh water and to discuss it any further would only be speculative. Therefore, only unlevelized costs are considered in this Chapter.

These estimates illustrate the importance of the water revenue for the small plants (1 to 10 MW), especially with the unit price of water at twice the present prevailing rate (i.e., Table 10). The cost of electricity without water production is 0.3 $/kWh and 0.18 $/kWh for the single stage 1 and 10 MWe land-based plants as compared with 0.28 $/kWh and 0.14 $/kWh for the prevailing water cost (Table 9) and 0.25 $/kWh and 0.11 $/kWh for the higher water cost (Table 10). In the case of the larger plants water would be important only as a product that might be needed at a specific site (or under scenarios wherein the cost of conventional water production increases by factors of three to four times the prevailing value).

The capital cost estimates given above indicate that OTEC is a capital-intensive technology. For example, the capital costs for oil-fired plants and coal-fired plants are less than $2,100/kW, as compared with the $10,700/kW and $6,000/kW given for the 10 MW and 50 MW plants in Tables 2 and 3. The 1 MW plant should be compared with diesel generators whose capital cost is less than 3% the cost of OTEC. However, OTEC incurs no fuel costs while conventional steam plants and diesel generators incur fuel costs. The levelized cost of OTEC electricity can be estimated from the equation given above; however, for the purpose of this report the capital cost of OTEC electricity, adjusted for the capital cost of the conventional technology (taken as $2,000/kW for oil or coal-fired plants and neglected for diesel generators) and the desalinated water by-product, will be compared with the fuel cost for conventional power plants to determine scenarios, given by the costs of electricity and water in a particular location, under which an OTEC plant of a given size could be cost competitive. Implicit in this approach is the assumption that O&M costs are similar for OTEC and conventional plants of the same power rating.

This approach can be formalized as follows for oil-fired plants:

$$(FC \times CC - WC \times PW) / (CF \times 8760 \times NP) < 1.6 \times 10^{-3} \times CB$$

Where, FC, CC, CF and NP are defined above, and

WC : unit price of water, in $\$/m^3$

PW : yearly production of water, in m^3/year

CB : cost of a barrel of fuel (42 gallons), in \$/barrel.

The production capacity factor (CF) is taken as 0.8 (80%) and the fixed charge for the capital (FC) as 0.1 (10%) and all values are expressed in present day costs. The water production of an open cycle plant is related to the amount of warm seawater utilized in the power cycle (i.e., between 0.4% and 0.5% of the warm seawater is flash evaporated in the process). As given in Tables 1, 2 and 3, this can be expressed as, PW = 130 x 10^6 gal/year/MW (or 50 x 10^4 m^3/year / MW-net). The second-stage described above would increase the water production in the case of an open cycle with second-stage by a factor of ˜ 2.2. In the case of the hybrid plant (i.e., flash evaporator/surface condenser downstream of closed cycle plant) the water production is equal to PW. Therefore, to determine the scenarios under which OTEC is competitive with oil-fired plants, the following expressions are used:

$$\frac{CC}{NP}^{*} = 110 \times CB + 5{,}000 \times WC, \qquad \text{for all cycles;}$$

and

$$\frac{CC}{NP}^{*} = 110 \times CB + 11{,}000 \times WC, \qquad \text{for open cycle with second-stage.}$$

* For the 10 MW, 50 MW and 100 MW cases, \$2,000/kW are subtracted from the capital cost of OTEC to account for the capital cost of the conventional steam power plant. For diesel generators their capital cost can be neglected. For the closed cycle, the second term is omitted. The first term on the right hand side is accurate within 6% , and the second within 10%

The scenarios identified following this procedure are summarized in Table 4 for the capital cost and net power given in Tables 1, 2 , 3 and 8 for 1, 10 and 50 MW plants. Diesel fuel is considered at the 1 MW level, while less expensive oil fuel is used for the 10 MW and 50 MW cases.

1 MW Plants

This approach indicates that the 1 MW open cycle with second-stage water production (i.e., Table 1) would be competitive in a scenario given by a location where a high unit price of water, 1.6 \$/m^3 (6 \$/kilogallon), and diesel fuel costs at \$45/barrel. The cost of producing desalinated water via RO would be 2.2 \$/m^3 at this fuel cost. This scenario corresponds to conditions existing in certain less-developed Island nations with small populations. For example, in 1989 the cost of imported diesel fuel paid by the power companies was \$47/barrel in Western Samoa; \$50/barrel in the Kingdom of Tonga; and, \$25/barrel in Molokai.

The analysis indicates that small open cycle OTEC plants (Table 1) without second-stage water production could only be competitive under a scenario of diesel at \$93/barrel and the high unit price for the water, 1.6 \$/m^3. This scenario does not appear likely. A 1 MW closed cycle plant (or open cycle without water production) would require a scenario where the diesel cost is \$165/barrel. The closed cycle plant with second-stage water production (hybrid plant) would require a scenario given by the high water cost, 1.6 $/m^3$, and $135/barrel.

It is interesting to note that the plant including a 300 ton AC system (~ 300-rooms hotel), described by Nihous, Syed and Vega (1989) and summarized in the last column of Table 1, would be competitive under a scenario given by $45/barrel and 1.25 $/m^3$ of water due to the additional revenue (electricity savings)generated by the use of 90 kg/s cold seawater as the chiller fluid for the air conditioning system. This amount of water amounts to only 3% of the water used for the 1 MWe OTEC plant. The 3,000 kg/s of cold seawater required for this size plant could support up to a 17,000 ton AC load. Therefore, the use of electricity savings from AC systems to offset the cost of OTEC electricity can only be consider for the small plants and is insignificant for the large plants discussed below. The use of cold seawater as the chiller fluid for AC systems represents a concept that is technically feasible and cost effective independently of OTEC.

10 MW Plants

For the 10 MW open cycle plant with second-stage water production, with a capital cost estimate of $14,700/kW (i.e., Table 2), a scenario given by $30/barrel of oil fuel and 0.85 $/m^3$ of water is required. For the single stage OC-OTEC, with a capital cost of $10,700/kW a scenario given by $44/barrel of oil fuel and 0.8 $/m^3$ of water is required. For the closed cycle system (or open cycle without water production) the scenario required is given by oil fuel at $ 80/barrel. For the hybrid plant (closed cycle with second stage) $79/barrel of oil fuel and 0.8 $/m^3$ of water or $43/barrel of oil fuel and 1.6 $/m^3$ of water are required.

These scenarios are plausible by the Year 2000 in a few small island nations. As indicated above, the capital cost for OTEC has been adjusted to account for the $2,000/kW capital investment for oil fuel plants. Once more, the additional water production makes the difference for OTEC for these relatively small plants. The cost of producing desalinated water via RO would be higher under all scenarios.

50 MW and 100 MW Plants

The land-based plant without water production summarized in Table 3 can be competitive under a scenario of fuel oil at $37/barrel. This is plausible by the Years 2000 to 2005. If water production is considered with a hybrid cycle plant, a scenario given by oil fuel at $49/barrel and unit price of water at $0.4/m^3$; or another scenario wherein the unit price of water doubles and oil fuel is $31/barrel would be required. These scenarios might occur by the first decade of next century. The cost of RO water production is greater under both scenarios.

The plantship, housing a closed cycle 50 MW plant, could be competitive under a scenario of $23/barrel. For the 100 MW case the required cost is $20/barrel. If hybrid plants are considered, with the desalinated water transported to shore via flexible pipes, the scenarios required would be given by $23/barrel and $0.55/m^3$ for the 50 MW plant and $20/barrel and $0.5/m^3$ (or $24/barrel and $0.4/m^3$) for the 100 MW plantship. The capital cost estimates used here are for plants deployed within 10 km from the shore line.

The capital costs and the scenarios required for plants at offshore distances of 50 km , 100 km and 200 km are given in Table 8b. For example, for the 100 MW plantship positioned 50 km offshore a scenario given by $28/barrel would be required.

These scenarios are plausible in the majority of the sites listed above in the section entitled "Site Selection Criteria for OTEC Plants." The simple analysis presented in this chapter indicates that the future of OTEC rests in closed cycle floating plants that can also be configured to produce desalinated water as required.

Co–Products of OTEC

The seawater needed for OTEC can also be used to support mariculture operations. The cold seawater contains large quantities of the nutrients required to sustain marine life. Organisms already grown in this environment include algae, seaweeds, shell fish and fin fish. Although a number of species have been identified as technically feasible, further work is required to identify cost effective culture methods for the available markets (Fast and Tanoue, 1988). The cold seawater can also be used as the chiller fluid for air-conditioning systems. A system based on this concept is presently utilized at NELH for one of the buildings.

In considering the economics of OTEC, it is appropriate to determine if multiple-product systems (e.g.: electricity, desalinated water, mariculture, AC systems) yield higher value by, for example, decreasing the equivalent cost of electricity. Unfortunately mariculture operations, as in the case of AC systems, can only use a relatively minute amount of the seawater required for OTEC systems. For example, the cold water available from a 1 MW OTEC plant could be used for daily exchanges of twenty-five 100m x 100m x 1m mariculture ponds, requiring at least 25 ha. Moreover, no mariculture operation requiring the use of the high-nutrient-deep-ocean water has been found to be cost effective. It is, therefore, recommended that OTEC be considered for its potential impact in the production of electricity and desalinated water and that mariculture and AC systems, based in the use of deep ocean water, be considered decoupled from OTEC.

A summary of the evaluation of co-products that the author has considered in conjunction with a 1 MW system is presented here for future reference and because the results were not published in the open literature. A mathematical model of the cold seawater utilization for mariculture and cooling applications was developed by Bhargava and Evans (1989). The California red abalone (*Haliotus rufescens*) and giant kelp (*Macrocystis spp.*) were chosen as the two species best suited for utilization of the cold seawater downstream of the OTEC plant. These species were selected for the model because they require seawater at approximately 15° C, abalone is a high value (sale price) product, and kelp is the naturally-grown feed for abalone. Dependence on outside sources for natural or artificial feed was, therefore, eliminated. Several other species considered (e.g., salmon) for OTEC-based, mariculture operations were not economically feasible because of the feed cost (Fast and Tanoue, 1988).

The mariculture operation was modeled based on a commercial farm operating at Keahole Point, Hawaii (i.e., Ocean Farms of Hawaii) buying cold seawater from the Natural Energy Laboratory of Hawaii (NELH). The operational cost in the form of a fee is incurred by the farm owner for the cold seawater resource. Likewise, associated capital costs are borne by the farm owner. Estimates on capital cost, electrical power con-sumption, annual farm production, and net annual revenue were made. Land available for the farm is nominally assumed to be 40,000 m^2 (4 hectares) in view of land availability restrictions in potential island markets.

The value-added benefit for OTEC is the annual fee that is paid by the farm for the cold seawater resource. In the example summarized below, the fee rate is nominally assumed to be that charged by NELH 666 $/ (yr-kg/s) [42 $/ (yr-gpm)]. With a cold seawater demand of 1700 kg/s (26,500 gpm) at 10.5 to 12° C., which is 53% of the amount discharged by the 1 MW OC-OTEC plant, the fee is estimated to be 1,132,200 $/year. The results obtained with this model can be summarized as follows:

Species Selected	Kelp and Abalone
Farm Area	4 Hectares
Cold Seawater Demand (OTEC Effluent)	1,700 kg/s
Electrical Power Demand	212 kW
Kelp Production	1527 ton-wet/yr
Abalone Production	65 ton-wet/yr
Capital Cost of Farm	7.82 $M
Gross Revenue from Abalone Sales @ 40 $/kg-wet	2.62 $M/yr
Cold Seawater Fee Paid to OTEC @ NELH Rate	1.13 $M/yr
Net Profit (Loss) to Farm Owner	(0.41) $M/yr

This analysis indicates that the fees charged by NELH would result in a loss of $410,000/year. A reduction of 50% in the fee charged by NELH for the cold seawater would yield a profit of $170,000/year (a return in capital investment of 2.2%). With the seawater available at no cost, the return in capital investment would be 9%.

Based on this study we concluded that the operation at Keahole Pt. could not be profitable. [Our conclusion was recently corroborated by the news media in Hawaii when it reported (January 1991) that the farm was bankrupt with monthly expenses at $200,000/month and revenues at $40,000/month].

The model for cooling was confined to a cold seawater-based, chiller system that would replace a refrigerant-based, chiller system. Chiller type air-conditioning (AC) systems are commonly used in hotels and large buildings. The chiller water temperature at inlet to the AC system has to be about 7.2° C for maximum human comfort which requires that the cold seawater temperature going to a counterflow, surface type, heat exchanger has to be 6.1° C or lower to meet the minimum pinch temperature requirement of 1.1° C. Therefore, the seawater for chiller application must be tapped upstream of the OTEC plant. Cold seawater is already being used for chiller water cooling by the Natural Energy Laboratory of Hawaii. The cooling capacity of the AC system is about 15 tons and the estimated reduction in electricity consumption is about 6000 kWh per month.

Estimates on capital cost, annual electrical power consumption, and annual costs were made. The electrical power requirement was found to be substantially lower for the cold seawater-based, chiller cooling system. For example, the electrical power saving for a 700-ton AC load (e.g., a 1,000-room hotel) is estimated to be 483 kW (3.38×10^6 kWh).

The value-added benefit for OC-OTEC could be taken to be an annual fee paid by the AC system owner for the cold seawater resource. The cold water required by the nominally-sized chiller system is estimated to be 135 kg/s, which is ˜ 4% of the demand for the 1 MWe-net OC-OTEC plant discussed herein. The example considered can be summarized as follows:

Cooling Application	Chiller Water Cooling
Electrical Power Saving	483 kW
Cold Seawater Demand (OTEC Influent)	135 kg/s
Cooling Load	700 tons
Capital Cost of Cooling System	563.5 $K
Gross Savings for the Cooling System Owner @ Electricity Rate of 0.10$/kWh (Hawaii)	338.0 $K/yr
Cold Seawater Fee Paid to OTEC @ NELH Rate	89.9 $K/yr
Net Savings for Cooling System Owner	135.3 $K/yr

The return in capital investment would be 24%, at an electricity charge of 0.10$/kWh.

In summary, the value-added benefits to OTEC from mariculture and chiller subsystems were assessed in terms of fees for the cold seawater resource. At the rate charged by NELH for the seawater resource, the mariculture operation was not profitable and the chiller system, using ˜ 4% of the cold seawater from a 1 MW plant, provided a 24% return in capital investment. It must, however, be noted that cold seawater fees from mariculture and chiller systems can only be significant for small OTEC systems.

In search of additional uses for OTEC seawater and the value-added benefits that might result, two additional studies were commissioned. Laws (1989) performed field experiments to determine the feasibility of growing *Gracilaria* in the OTEC effluent, for chemicals (e.g., agar) or methane production. The objective was to determine whether the required CO_2 bubbling could be eliminated by water exchange with the OTEC effluent. Unfortunately, Laws found that the availability of the OTEC effluent did not eliminate the need for an external source of CO_2 and that the production of agar or methane from *G. coronopilofia* is not cost effective.

In search for other aquatic plants (excluding seaweeds) of potential economic value that could benefit from the availability of the OTEC effluent, Weaver (1990) performed a study based on archival information and personal interviews to establish the chemical composition of aquatic plants; information on their mass-culture; and, to identify products with established or potential demand by industry (e.g., food, food-additive, chemical or pharmaceutical) including their economic value. Weaver considered: *Porphyridium, Diatoms, Dunaliella, Spirulina, Anabaena Azolla* and found that, although there exists potential for products extracted form these microalgae, there was no specific requirement for the OTEC effluent nor was there an identifiable benefit from it.

Based on these studies it can be stated that OTEC-based mariculture is in its formative years and not ready for commercialization, or transfer to nations under development. With the exception of the relatively small use of the cold seawater as AC chiller fluid, OTEC should be considered for its potential production of electricity and desalinated water.

OTEC Energy Carriers

Several means of energy transport and delivery from OTEC plants deployed throughout the tropical oceans and distances exceeding those listed in Table 8b (> 200 km) have been considered (Konopka, et al, 1976). OTEC energy could be transported via electrical, chemical, thermal and electrochemical carriers. The submarine power cable has been considered above in the discussion of the 50 and 100 MW plantships (Tables 8a and 8b). The technical evaluation of non-electrical carriers leads to the consideration of hydrogen produced using electricity and fresh water generated with OTEC technology. The product would be transported in liquid form to land to be primarily used as a transportation fuel.

A 100 MWe-net plantship can be configured to include the following functions, in addition to supplying the fresh water required for the electrolysis and the crew:

- <u>AC-DC Rectification</u> (97% Efficient)
- <u>Electrolysis</u> (79% Efficient;
Specific power consumption 4.2 kWh/Nm^3 H_2
Distilled water consumption 0.886 liter/Nm^3 H_2
Auxiliaries Power 0.517 MW)
- <u>Liquefaction</u> (97% Efficient, Power Consumption 11.3 kWh/kg–LH_2 ;
92.5% of GH_2 input is liquefied)
- <u>Onboard Storage</u> (98% Efficient)
- <u>Ocean Transport</u> (91% Efficient; 1,600 km)
- <u>Land Storage</u> (98% Efficient)

In this fashion, the 100 MWe of OTEC electricity yield 1298 kg/h of liquid hydrogen with an upper heating value of 39.41 kWh/kg corresponding to a thermal efficiency of 51%. The production cost of liquid hydrogen delivered to the harbor is given by the sum of the OTEC electricity component (0.069 $/kWeh for the 100 MWe plantship) plus the hydrogen production and delivery component. The estimated capital cost for the non-OTEC components is $290,000,000 (Konopka, et al, 1976 and Wurster, et al, 1990). For the economic parameters used in the estimate of the cost of OTEC electricity (e.g.: fixed rates, O&M) the cost, given in 1990 dollars, per million Btu is 40 $/MBtu for the electricity component and 31 $/MBtu for the hydrogen subsytem for a total cost for the product delivered to the harbor of 71 $/MBtu (3413 Btu/kWh). This is equivalent to gasoline (@0.125 MBtu/ US gallon) priced at $9/gallon or crude oil (@ 5.8 MBtu/barrel) priced at $412/barrel. Considering the lowest capital cost and the highest system thermal efficiency projected in the literature the cost for the product delivered to the harbor is reduced to 47 $/MBtu corresponding to gasoline at $6/gallon or crude oil at $273/barrel.

The situation is similar for the others energy carriers considered in the literature. For example, for liquid ammonia the cost of the delivered product (liquid hydrogen) is 88% of the cost given above; for methylcyclohexane the cost is 96%; and, for metal hydrides 108%. For a land-based OTEC system a reduction of 30% in the cost of the end product is achieved (i.e.: 50 $/MBtu instead of 71 $/MBtu for the baseline case) by increasing the production of liquid hydrogen by 12% and reducing the capital cost on the non-OTEC components by 50%. All carriers considered yield costs higher that those estimated for the submarine power cable (Table 8b) Therefore, the only energy carrier that is cost effective for OTEC energy is the submarine power cable.

Externalities in the Production and Consumption of Energy

At present, the external costs of energy production and consumption are not considered in the determination of the charges to the user. Considering all stages of generation, from initial fuel extraction to plant decommissioning, it has been determined that no energy technology is completely environmentally benign. The net social costs of the different methods of energy production is a topic under study. Hubbard (1991) has published the range of all estimates reported in the literature for the costs due to: corrosion, health impacts, crop losses, radioactive waste, military expenditures, employment loss, subsidies (tax credits and research funding for present technologies). The sum of all estimates yields a range of 78 to 259 billion dollars per year. Excluding costs associated with nuclear power, the range is equivalent to adding from $85/barrel to $327/barrel. As minimum, consider that the costs incurred by the military, in the USA, to "safeguard" oil supplies from overseas is at least $15 billion or equivalently $23.5/barrel. Accounting for externalities might eventually help the development and expand the applicability of OTEC, but in the interim the scenarios that have been identified herein should be considered.

It is interesting to note that discussions, in the public sector, regarding taxing the electricity produced by non-renewable resources at a rate of $0.02/kWh is equivalent to adding $13 per barrel (42 gallons) of fuel to the cost of electricity production. This tax would not suffice to make small OTEC plants cost effective in industrialized nations; however, in the case of the larger plants this tax would work in favor of OTEC.

Development Requirements (circa 1990)

The analysis presented herein indicates that there is a market for OTEC plants that produce electricity and water. Industrialized nations and islands, as well as island nations under development, could make use of 50 MW to 100 MW closed cycle or hybrid plants housed in plantships (e.g.: Tables 8a and 8b). A few less developed or smaller islands could use of open cycle plants with second-stage additional water production (e.g., Tables 1 and 2).

However, operational data must be made available, for example, to establish production factors and plant reliability. This data can only be obtained by building and operating demonstration plants scaled from the commercial-size plants listed in Tables 1, 2, 3, and 8. A plan aimed at achieving the development of OTEC under the scenarios discussed in this chapter is summarized in Table 11 (SERI, Appendix D, 1990).

The potential locations considered to develop this plan with the aim of 2100 MWe installed by the Year 2010 were (Note: that 95% of the plants would be based on the closed cycle):

Small Pacific Islands	100 MW	(Open Cycle)
Taiwan............................	400 MW	(Closed or Hybrid Cycle)
Oahu	200 MW	(Closed or Hybrid Cycle)
Hawaii	50 MW	(Closed or Hybrid Cycle)
Molokai	10 MW	(Open Cycle)
Kauai	40 MW	(Closed or Hybrid Cycle)
Philippines......................	400 MW	(Closed or Hybrid Cycle)
Indonesia	200 MW	(Closed or Hybrid Cycle)
India................................	200 MW	(Closed or Hybrid Cycle)
Puerto Rico.....................	200 MW	(Closed or Hybrid Cycle)
Gulf of Mexico	300 MW	(Closed or Hybrid Cycle)

It is interesting to note that the earlier study by Dunbar (1981) considered a potential market of 577,000 MW of new baseload, electric power facilities.

Conclusions

The identification of the scenarios—given by the cost of fuel oil and the production cost of water—under which OTEC systems are cost competitive indicates that closed cycle OTEC plants of at least 50 MWe and as much as 100 MWe capacity must be considered. If desalinated water is required, a hybrid system configured with second stage water production is applicable. The lowest costs correspond to plantships deployed close to the shoreline. An exception is found under scenarios with high costs for the fuel oil and the conventional production of water, where small (1 to 10 MWe) land-based OC-OTEC plants, with second stage for additional water production, are cost effective. These scenarios correspond to small markets found in only a few island nations. These conclusions must be confirmed by designing, constructing and operating demonstration plants scaled from the commercial size plants. A 5 MWe plantship with second stage water production is an appropriate size for the demonstration plant, scaled from the 50 to 100 MWe plants. Likewise a 1 MWe OC-OTEC demonstration plant with second stage additional water production must be considered as a scaled version of the plants for the small island market.

The small OC-OTEC plants considered in this chapter could be sized to produce from 1 to 10 MW electricity, and at least 450 thousand to 9.2 million gallons of fresh water per day (1,700 to 35,000 m^3/day). That is, the needs of LDCs communities with populations ranging from 4,500 to as much as 100,000 could be met. This range encompasses the majority of less developed island nations throughout the world.

The larger CC-OTEC or hybrid cycle plants can be used in either market for producing electricity and water. For example, a 50 MW hybrid cycle plant producing as much as 16.4 million gallons of water per day (62,000 m^3/day) could be tailored to support a LDC community of approximately 300,000 people or as many as 100,000 people in an industrialized nation. It is interesting to note that the state of Hawaii could be independent, of conventional fuels for the production of electricity, by utilizing the largest floating OTEC plants (50 to 100 MWe-net) for the larger communities in Oahu (˜ 800,000 residents), Kauai, Maui, and the Island of Hawaii (˜ 100,000 residents), as well as smaller plants satisfying the needs of Molokai (˜ 8,000 residents). Taiwan (ROC) could use several plants to meet additional requirements projected for the near future. The majority of the nations listed in the previous section could meet all their electricity and water requirements with OTEC.

An assessment of the state of the art and evaluation of potential developments reveals that the only energy carrier that is cost effective for OTEC energy is the submarine power cable and that, with the exception of the relatively small use of the cold seawater as AC chiller fluid, in conjunction with the 1 MWe land-based plants, OTEC should only be considered for its potential production of electricity and desalinated water.

Accounting for externalities in the production and consumption of energy might eventually help the development and expand the applicability of OTEC, but in the interim the scenarios that have been identified herein should be considered. Conventional power plants pollute the environment more than an OTEC plant should and the fuel for OTEC is unlimited and free, as long as the sun heats the oceans; however, it is futile to use these arguments to convince the financial community to invest in OTEC plants without an operational record.

References

AES Corporation, "AES Closes $383.5 Million Project Financing for Construction of Power Plant in Hawaii," Press Release, April 3, 1990. Contact: P. Hanrahan, Arlington, Virginia (703) 358-0506.

Bhargava, A., Evans, D.E., "OC-OTEC Computer Model Incorporating Electricity and Desalinated Water Production, and Cold Seawater Utilization for Mariculture and Cooling Applications," PICHTR Publication, Honolulu, Hawaii, August 1989.

Dunbar, L.E., "Market Potential for OTEC in Developing Nations," Proceedings, 8th Ocean Energy Conference, Washington, D.C., June 1981.

Electric Power Research Institute, "Ocean Energy Technologies: The State of the Art," EPRI AP-4921, November 1986.

Fast, A.W., Tanoue, K.Y., "OTEC Aquaculture in Hawaii," University of Hawaii SEAGRANT College Program, Contribution No. 59 (UNIHI–SEAGRANT–MR–89–01), November 1988 (177 pages).

Green, H.J., Guenther, P.R., "Carbon Dioxide Release from OTEC Cycles," Proceedings, International Conference on Ocean Energy Recovery, Honolulu, Hawaii, November 1989. Published by the American Society of Civil Engineers.

Hubbard, H.M., "The Real Cost of Energy," *Scientific American,* April 1991.

IFREMER, Centre de Brest, Projet E.T.M., "Situation des Etudes d'Avant-Projet de la Centrale E.T.M. de Tahiti au 31.03.85," Report #DIT/SP/ETM 85.312 MG/ES, August 1985.

Konopka, A.J., Talib, A., Yudow, B., Biederman, N., "Optimization Study of OTEC Delivery Systems Based on Chemical–Energy Carriers," Institute of Gas Technology (IGT), December 1976, ERDA Report No. NSF–C1008 (AER–75–00033).

Laws, E.A., "The Feasibility of Growing Gracilaria in OTEC Effluent," University of Hawaii at Manoa, prepared for PICHTR, January 1989.

Nihous, G.C., Syed, M.A., and Vega, L.A., "Conceptual Design of a Small Open–Cycle OTEC Plant for the Production of Electricity and Fresh Water in a Pacific Island," Proceedings, International Conference on Ocean Energy Recovery, Honolulu, Hawaii, November 1989. Published by the American Society of Civil Engineers.

Nihous, G.C., Udui E. and Vega, L.A., "Preliminary Evaluation of Potential OTEC Sites: Bathymetry and Feasibility," prepared by PICHTR for the Commonwealth of the Northern Mariana Islands, Contract #C549994-01 with the U.S. Department of Energy, Territorial Assistance Program, October 1989.

Solar Energy Research Institute (SERI), et al, "The Potential of Renewable Energy: An Interlaboratory White Paper," SERI/TP–260–3674, March 1990. Prepared for the Office of Policy, Planning and Analysis, U.S. Department of Energy in support of the National Energy Strategy. Available from: National Technical Information Service. [Appendix D. *Ocean Energy Technologies*]

Shyu, Chuen-Tien, "Topography of the Eastern Taiwan Coastal Areas," Proceedings of the International Workshop on Artificial Upwelling and Mixing in Coastal Waters, pp. 124–132, Keelung, Taiwan, June 1989.

Vega, L.A., Bailey, S., "Assessment of OTEC-Based Mariculture Operations," Proceedings, 8th Ocean Energy Conference, Washington, D.C., June 1981.

Vega, L.A., Nihous, G.C., "At-Sea Test of the Structural Response of a Large Diameter Pipe Attached to a Surface Vessel," Proceedings, Offshore Technology Conference, No. 5708, pp. 473-480, Houston, Texas, May 1988.

Vega, L.A., Nihous, G.C., Lewis, L. Resnick, A., and Van Ryzin, J., "OTEC Seawater Systems Technology Status," Proceedings, International Conference on Ocean Energy Recovery, Honolulu, Hawaii, November 1989. Published by the American Society of Civil Engineers.

Weaver, E.C., "Use of OTEC Water for Cultivating Aquatic Plants of High Economic Value," prepared for PICHTR, March 1990.

Wurster, R., Malo, A., "The Euro–Quebec Hydro–Hydrogen Pilot Project," Proceedings of the 8th World Hydrogen Energy Conference, Honolulu, Hawaii (held in July 1990), Vol. 1, p. 59.

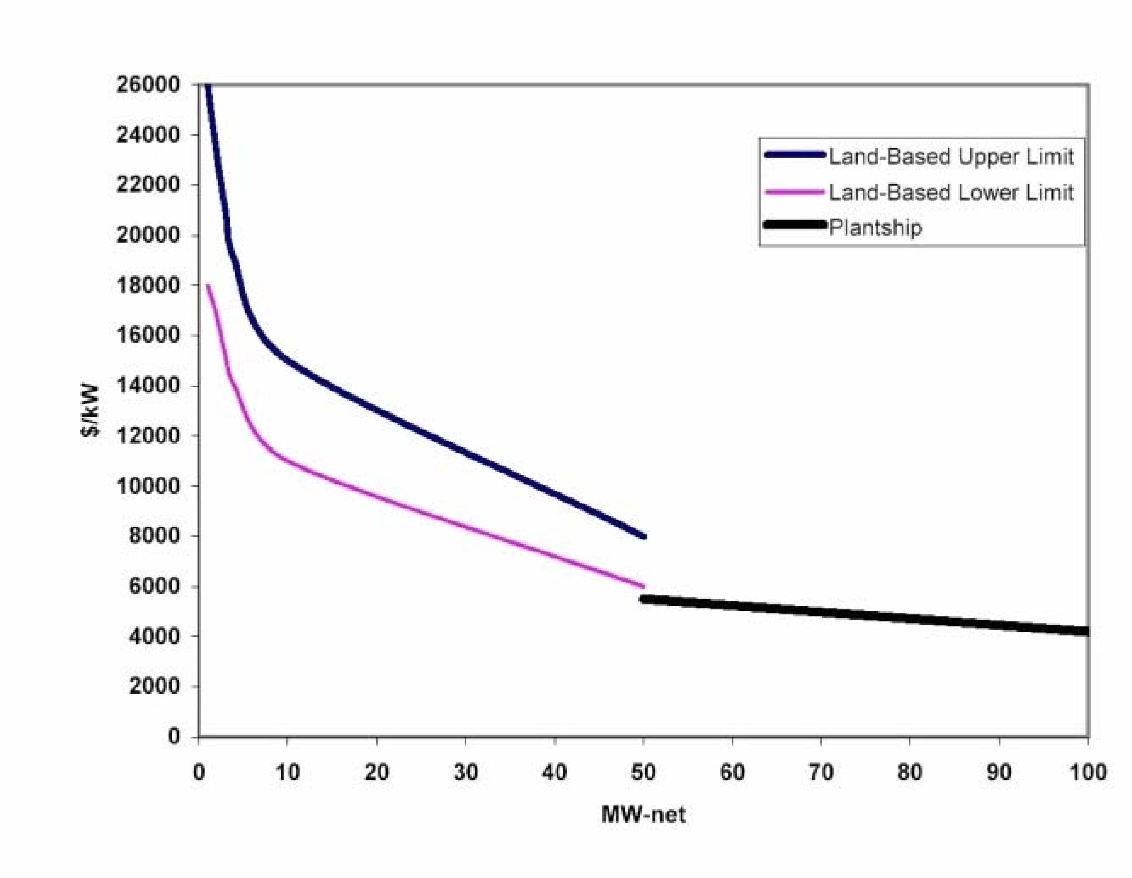

Figure 1. **Capital Cost for Single Stage OTEC Plants (1992)**

PLANT NOMINAL SIZE:	1 MW; OC-OTEC	1 MW; OC-OTEC with 2nd-Stage	1 MW; OC-OTEC with 2nd-Stage and 300 ton A-C
PRODUCTION:			
Electricity	9.5×10^6 kWh	8.8×10^6 kWh	8.4×10^6 kWh plus the A-C equivalent
Water	0.45 MGD (1,700 m^3/day)	1.06 MGD (4,000 m^3/day)	1.06 MGD
A-C Electricity			Equivalent to 1.7×10^6 KWh
CAPITAL COST:	18,200 $/kW-net	23,000 $/kW	20,000 $/kW (adjusted)
YEAR DEPLOYED:	1995	1995	1995

NOTE: Estimates are from Table 5 for the Capital Cost expected after engineering development in compressors and turbine efficiency as well as for cost reductions in surface condensers from \$215/m^2 to \$100/m^2. State-of-the-art seawater piping systems are used. The estimate for the plant with a 300 ton A-C is for electricity production savings due to the use of 90 kg/sec of cold seawater (3% of the total cold water required for power cycle) as a chiller fluid for a standard A-C unit.

Table 1. **Capital Cost Estimates ($/kW-net) for 1 MW Land-Based Plants in 1990 Dollars**

PLANT NOMINAL SIZE:	10 MW; OC-OTEC	10 MW; OC-OTEC with 2nd-Stage
PRODUCTION:		
Electricity	70×10^6 kWh	63×10^6 kWh
Water	4 MGD (15,000 m^3/day)	9.2 MGD (35,000 m^3/day)
CAPITAL COST:	10,700 $/kW-net	14,700 $/kW
YEAR DEPLOYED:	2000	2000

NOTE: Estimates are from Table 6 for the Capital Cost expected after cost reductions in surface condensers from\$215/m^2 to \$100/m^2; engineering development resulting in improved turbines and vacuum compressors and new cold-water-pipe technology.

Table 2. **Capital Cost Estimates ($/kW-net) for 10 MW Land-Based Plants in 1990 Dollars**

PLANT NOMINAL SIZE:	50 MW; CC-OTEC	50 MW; Hybrid Ammonia Power Cycle with 2nd-Stage Water Production
PRODUCTION:		
Electricity	336 x 10^6 kWh	280 x 10^6 kWh
Water	n/a	16.4 MGD (62,000 m^3/day)
CAPITAL COST:	6,000 $/kW	9,4000 $/kW
YEAR DEPLOYED:	2000 to 2005	2000 to 2005

NOTE: Estimates are from Table 7 adjusted as described in Table 2.

Table 3. **Capital Cost Estimates ($/kW-net) for 50 MW Land-Based Plants in 1990 Dollars**

NOMINAL NET POWER (MWe)	**TYPE**	**SCENARIO REQUIREMENTS**	**SCENARIO AVAILABILITY**
1 *(Table 1)*	Land-Based OC-OTEC with 2nd-Stage additional Water Production	• \$45/barrel of diesel • \$1.6/m^3 water	South Pacific Island Nations by Year 1995
10 *(Table 2)*	Land-Based (as above)	• \$30/barrel of fuel oil • \$0.85/m^3 water	American Island Territories and other Pacific Islands by Year 2000
50	Land-Based Hybrid (ammonia power cycle with Flash Evaporator downstream)	• \$49/barrel of fuel oil • \$0.4/m^3 water **– or –** • \$31/barrel • \$0.8/m^3 water	Hawaii, if fuel or water cost doubles by Year 2000
(Table 3)	Closed-Cycle Land-Based	• \$37/barrel	
50 & 100	Closed-Cycle Plantship (50 MW)	• \$23/ barrel	Present
(Table 8)	Closed-Cycle Plantship (100 MW)	• \$20/ barrel	

- OC-OTEC limited by turbine technology to 2.5 MW modules or 10 MW plant (with four modules)
- CC-OTEC or Hybrid (water production downstream of closed-cycle with flash evaporator)

Table 4. **OTEC Market Penetration Scenarios (1992)**

	1 MWe OC-OTEC (1990)	1 MWe OC-OTEC (1995)	COMMENTS
• **STRUCTURE**	4,400	3,700	Structural Improvements after demonstration plant
• **SEAWATER SYSTEM (Pipes and Pumps)**	12,300	7,600	Improvement in SWS technology
• **POWER SYSTEMS**			
- **Heat Exchangers**	3,500	2,000	Surface Condenser reduced from $215/m^2 to $100/m^2
- **Turbine-Generator and Vacuum Compressor**	3,700	3,200	Increases in efficiencies for T-G and Vacuum Compressor systems augment net power from 1156 to 1356 kW
• **OTHER**	2,000	1,700	Engineering Development
TOTAL	**25,900**	**18,200**	

NOTE: Second Stage Water Production Unit doubles desalinated water production, decreases net power by 100 kW and capital costs increase by $4.3 M (e.g., 23,000 $/kW by Year 1995).

Table 5. **Potential Reduction in Capital Cost ($/kW) by Year 1995, Expressed in 1990 Dollars, for a Land-Based 1 MWe OC-OTEC Plant**

	10 MWe OC-OTEC (1990)	10 MWe OC-OTEC (2000)	COMMENTS
• **STRUCTURE**	1,500 *(10%)*	1,500 *(14%)*	---
• **SEAWATER SYSTEM (Pipes and Pumps)**	6,000 *(40%)*	3,700 *(34%)*	New CWP Technology (d > 1.6 m);
• **POWER SYSTEMS**			
- **Heat Exchangers**	3,500 *(23%)*	2,000 *(19%)*	Surface Condenser reduced from $215/m^2 to $100/m^2
- **Turbine-Generator and Auxiliaries**	2,500 *(17%)*	2,000 *(19%)*	Engineering Development results in improved turbine and vacuum compressor
• **OTHER**	1,500 *(10%)*	1,500 *(14%)*	---
TOTAL	**15,000**	**10,700**	

NOTE: Second Stage Water Production Unit doubles desalinated water production, decreases net power by 1,000 kWe and augments capital investment by $25 M (e.g., 14,700 $/kW by Year 2000)

Table 6. **Potential Reduction in Capital Cost ($/kW) by Year 2000, Expressed in 1990 Dollars, for a Land-Based 10 MWe OC-OTEC Plant**

	50 MWe CC-OTEC (1990)		50 MWe CC-OTEC (2000)		COMMENTS
• **STRUCTURE**	1,500	*(18%)*	1,500	*(25%)*	---
• **SEAWATER SYSTEM (Pipes and Pumps)**	2,400	*(29%)*	1,700	*(28%)*	New CWP Technology
• **POWER SYSTEMS**					
- **Heat Exchangers**	2,500	*(30%)*	1,200	*(20%)*	Condenser reduced from $215/m^2 to $100/m^2
- **Turbine-Generator**	1,200	*(15%)*	1,000	*(17%)*	Engineering Development
• **OTHER**	600	*(8%)*	600	*(10%)*	---
TOTAL	**8,200**		**6,000**		

NOTE: For the Hybrid Plant (Second Stage Water Production), net power is decreased by 8,000 kW and capital cost is incremented by $60 M (e.g., 9,400 $/kW by Year 2000)

Table 7. **Potential Reduction in Capital Cost ($/kW) by Year 2000, Expressed in 1990 Dollars, for a Land-Based 50 MWe CC-OTEC Plant**

	MOORED 50 MWe CC-OTEC (1990)	MOORED 50 MWe CC-OTEC (2000)	COMMENTS
• **VESSEL / MOORING AND POWER CABLE**	1,800 *(26%)*	1,200 *(26%)*	Engineering Development
• **SEAWATER SYSTEM (Pipes and Pumps)**	800 *(12%)*	600 *(13%)*	Engineering Development
• **HEAT EXCHANGERS**	2,500 *(36%)*	1,200 *(26%)*	Condenser and Evaporator reduced from \$215/m^2 to \$100/m^2
• **TURBINE-GENERATOR**	1,200 *(17%)*	1,000 *(22%)*	Engineering Development
• **OTHER**	600 *(9%)*	600 *(13%)*	---
TOTAL	**6,900**	**4,600**	

Table 8a. **Potential Reduction in Capital Cost (\$/kW) by Year 2000, Expressed in 1990 Dollars, for Floating 50 MWe CC-OTEC Plants**

OFFSHORE DISTANCE	MOORED 50 MWe CC-OTEC (2000)	MOORED 100 MWe CC-OTEC (2000)	SCENARIO REQUIRED FOR 100 MWe PLANT
10 km	4,600	4,200	$ 20 / barrel
50 km	5,500	5,000	$ 28 / barrel
100 km	6,600	6,000	$ 37 / barrel
200 km	8,900	8,100	$ 55 / barrel

Table 8b. **Capital Cost ($/kW) for Single Stage Floating Plants, as a Function of Offshore Distance Projected by Year 2000 After Engineering Development and the Operation of Demonstration Plant**

NOMINAL PLANT CF= 80%	Production Electricity kWh	Production Water m^3/day	Capital Cost $/kW-net	Fixed Charge	O&M % of Capital	Electricity Cost with Water Production Credit $/kWh
1 MW OC OTEC Land Based	9.50E+06	1,700	18,200	10%	1.7%	0.28
1 MW OC OTEC Land Based 2nd Stage	8.80E+06	4,000	23,000	10%	1.7%	0.32
10 MW OC OTEC Land Based	7.00E+07	15,000	10,700	10%	1.5%	0.14
10 MW OC OTEC Land Based 2nd Stage	6.30E+07	35,000	14,700	10%	1.5%	0.16
50 MW CC OTEC Land Based	3.36E+08	0	6,000	10%	1.5%	0.10
50 MW CC OTEC Land-Hybrid	2.80E+08	62,000	8,700	10%	1.5%	0.11
50 MW CC OTEC Floater	3.80E+08	0	4,600	10%	1.5%	0.08
50 MW CC OTEC Floater-Hybrid	3.20E+08	62,000	6,700	10%	1.5%	0.08

Table 9. **Cost of OTEC Electricity with Desalinated Water Credit at $0.4/m^3 ($1.5/1000 gallons)**

NOMINAL PLANT CF= 80%	Production Electricity kWh	Production Water m^3/day	Capital Cost $/kW-net	Fixed Charge	O&M % of Capital	Electricity Cost with Water Production Credit $/kWh
1 MW OC OTEC Land Based	9.50E+06	1,700	18,200	10%	1.7%	0.25
1 MW OC OTEC Land Based 2nd Stage	8.80E+06	4,000	23,000	10%	1.7%	0.25
10 MW OC OTEC Land Based	7.00E+07	15,000	10,700	10%	1.5%	0.11
10 MW OC OTEC Land Based 2nd Stage	6.30E+07	35,000	14,700	10%	1.5%	0.08
50 MW CC OTEC Land Based	3.36E+08	0	6,000	10%	1.5%	0.10
50 MW CC OTEC Land-Hybrid	2.80E+08	62,000	8,700	10%	1.5%	0.08
50 MW CC OTEC Floater	3.80E+08	0	4,600	10%	1.5%	0.08
50 MW CC OTEC Floater-Hybrid	3.20E+08	62,000	6,700	10%	1.5%	0.05

Table 10. **Cost of OTEC Electricity with Desalinated Water Credit at $0.8/m^3 ($3/1000 gallons)**

YEARS		PROJECT	FUNDS REQUIRED
1990—1995	A)	• Reduce the cost of Surface Condensers; • Develop Low Pressure Steam Turbines rated at about 2.5 MWe; and, • Develop Large Diameter Cold Water pipes for Land–Based Plants (> 1.6 m).	$ 10M
	B)	OC-OTEC / 2nd-stage Demonstration Plant (1 MWe / 3,500 m^3/day) using state-of-the-art	$ 30 M
1995—2000	C)	Deploy Land-Based Plants Optimized from (B) (Total 5 MWe / 17,500 m^3/day)	International Banking / Aid Community
	D)	Hybrid Land-Based Demonstration Plant (optional) (5 MWe / 7,500 m^3/day) using newly developed CWP	$ 75 M
	E)	CC-OTEC Plantship Demonstration Plant (5 MWe) using existing technology	$ 60 M
2000—2005	F)	Deploy several Land-Based Plants in Pacific and Asia. Optimized from (D)	Private
	G)	Deploy several 50 to 100 MWe Plantship in Tropical Waters Optimized from (E)	Private
2005—2010	H)	Provide Projected Power and Water Increase in small Pacific Islands, and part thereof in Oahu, Taiwan, Philippines, etc., and Plantships (e.g.: Cumulative Deployed Power : 2100 MWe)	Cumulative Capital Investment $13 Billion (for 2100 MWe)

Table 11. **OTEC Development Program Required (circa 1990)**