The Hydrogen Economy of 2050: OTEC Driven?

Joe Van Ryzin, Ph.D., P.E.
Makai Ocean Engineering, Inc.

Patrick Grandelli, P.E.
Makai Ocean Engineering, Inc.

David Lipp
Makai Ocean Engineering, Inc.

Richard Argall
Makai Ocean Engineering, Inc.

Abstract **– A technical and economic model of numerous future Ocean Thermal Energy Conversion plants serviced by shuttle tankers was compared with other future energy sources described by U.S. Dept. of Energy's Hydrogen Economy documents. OTEC is more expensive than coal or nuclear power sources, but is comparable to land-based renewable energy sources. The system's high capacity factor, land-use avoidance and reasonable technical risk mean that OTEC could be an attractive future energy source if a hydrogen economy develops. An intermediate step using OTEC hydrogen to replace imported ammonia is also considered and may be cost-competitive soon.**

INTRODUCTION

This paper describes results from a software model that simulates the technical and economic aspects of operating numerous Ocean Thermal Energy Conversion (OTEC) plants to supply a hydrogen economy. The first section introduces the envisioned energy sources for the hydrogen economy. Next, the various modules of the OTEC model software are presented and some of the optimization steps are described. Section three presents model results based upon scenarios considering type of product produced, logistics, and financial interest rate. The fourth section compares these results with the other envisioned energy sources. The fifth section briefly describes a modeled OTEC plantship that produces ammonia instead of hydrogen fuel using present costs and technology. Finally, a conclusion is presented that for a massive scale, OTEC is the most feasible renewable technology because it does not use land.

HYDROGEN ENERGY SUPPLIES IN 2050

A. OTEC Study for the Office of Naval Research

This paper describes the results of an Office of Naval Research (ONR) study to broadly assess the economic and technical feasibility of numerous OTEC plants that supply hydrogen to a future hydrogen fueled economy. The study followed from an ONR Request for Proposals for firms to develop an OTEC plant conceptual design to furnish hydrogen to U.S. Navy users. Makai Ocean Engineering, Inc. suggested that an existing deep ocean water parameterized design tool could be adapted to evaluate OTEC hydrogen supplied to a widespread hydrogen economy, such as described by the U.S. Department of Energy's (DOE) hydrogen vison plans [1-4].

B. DOE's Vision of a Hydrogen Economy

By 2050 it is supposed that petroleum will be rare and expensive, and that hydrogen will be used to power fuel cell vehicles. Hydrogen fuel is attractive due to high efficiency and lack of pollution. However, hydrogen must be synthesized from other energy sources.

The vast majority of today's 42 million tons per year of hydrogen is created by reforming of natural gas. Sixty percent is used for ammonia production, 23% for oil refining, and the remainder is used for chemical, metallurgical, and space purposes [5]. Other hydrogen production techniques include coal gasification, conversion of biomass or electrolysis. Table 1 lists seven future scenarios wherein each production method yields enough fuel to drive 150 million light duty vehicles (about 75% of present vehicles). It is clear that both natural gas reforming and coal gasification are unsustainable over the long-term. Unfortunately, this table omitted ocean technologies. This document unfortunately omitted ocean technologies. This current ONR work has focused on viewing OTEC hydrogen in the same context.

TABLE 1: HYDROGEN PRODUCTION FROM DOMESTIC RESOURCES TO PRODUCE 40 MILLION SHORT TONS OF HYDROGEN FUEL FOR 150 MILLION VEHICLES

Resource	Needed for Hydrogen Annually	Resource	Footprint Required
Reforming and / or Partial Oxidation			
Natural Gas	95 million tons	49 years	400 plants
Coal	310 million tons	89 years	280 plants
Biomass	400-800 million tons	n/a	400 - 600 plants
Water Electrolysis or Thermo-Chemical			
Wind	555 GW_e	n/a	North Dakota Class 3 Wind
Solar	740 GW_e	n/a	3750 sq. miles
Nuclear (electrolysis)	216 GW_e	n/a	200 plants
Nuclear (thermo-chemical)	300 GW_{th}	n/a	125 plants
Above information is condensed from [3].			
OTEC	216 GW_e	n/a	500 - 1000 plants

C. Challenges of Hydrogen Energy Storage &Transport

Someday, another type of fuel will supplant the current petroleum-based fuel infrastructure. As Makai investigated the hydrogen economy, it became clear that significant breathroughs must occur for hydrogen to become this new fuel. The National Academy of Engineering (NAE) calls these hydrogen economy breakthoughs the "Four pivotal questions" [5]:

1. When will vehicular fuel cells improve enough to gain a meaningful market share of the automotive market?

2. Can carbon be sequestered with environmental safety at a competitive cost?

3. Can vehicular hydrogen storage systems provide equivalent cost and safety as today's vehicles?

4. Can the not-yet-built hydrogen infrastructure sucessfully compete against the benefits of the existing energy infrastructure?

A technical breakthrough for question 3, which addresses hydrogen's storage and shipping difficulties, is especially critical since OTEC plantships will create hydrogen distant from users. As an example of this importance, consider the pricing difference between natural gas and gasoline shown in Fig 1. Gasoline is 60% more expensive than natural gas on a per-energy basis, yet vastly more vehicles use gasoline instead of natural gas. The primary reason gasoline is preferred is the cost and complexity of pressurized tanks or cryogenic liquids.

Molecular hydrogen is more difficult to handle than natural gas due to hydrogen's low density, high energy and small molecule size. For this reason, the NAE has recommended ceasing research on high pressure hydrogen tanks and cryogenic storage tanks so that the funds saved can be channeled towards dramatic breakthroughs such as "…some sort of reversible solid system…" [5]. For this analysis of OTEC in the future, we, like the DOE, have assumed that these breakthroughs will occur.

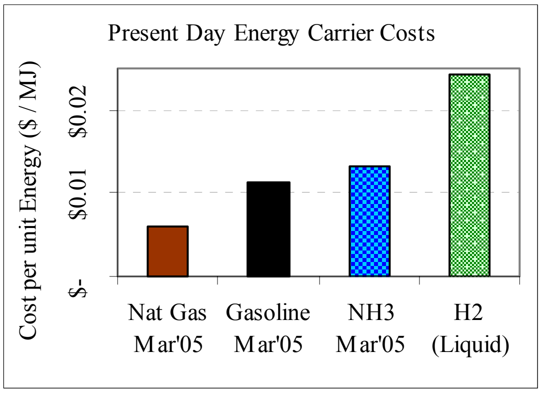

Fig. 1. Spot price of natural gas, gasoline and ammonia compared on an energy basis with liquid hydrogen [5,7,8]

AN OTEC ECONOMIC & TECHNICAL MODEL

A. Adaptation from previous work

Makai has done several OTEC projects during the past 25 years, including the Mini-OTEC pipe-mooring, hydrodynamic testing of large cold-water pipes, design and construction management of four deep pipelines used for OTEC tests, aluminum heat exchanger testing and OTEC plant conceptual designs. We have commercialized this research work by designing deep cold water intake pipelines and by developing a parameterized technical and economic software to quantify the value of deep cold water using life cycle financial analysis. This software tool facilitates matching the system's technical characteristics and finance parameters to maximize profitability.

B. Description of model

For ONR's OTEC project, Makai used our concepts and existing kernel of software to develop an integrated life cycle cost analysis of the technical and financial aspects of an OTEC plant. The analysis for this one plant is expanded to simulate numerous identical plants operating in the same oceanic temperature region models relevant logistics and finance relationships. The product of the plant(s) could be selected to be compressed or liquid hydrogen, or anhydrous ammmonia (NH_3). The first two products would be directly consumed by a hydrogen economy, while ammonia is less costly to store and transport and could replace imported ammonia produced from foreign natural gas.

Fig. 2 shows an outline of the various modules that make up the model, and the overall logic of the software. A brief description of each module follows.

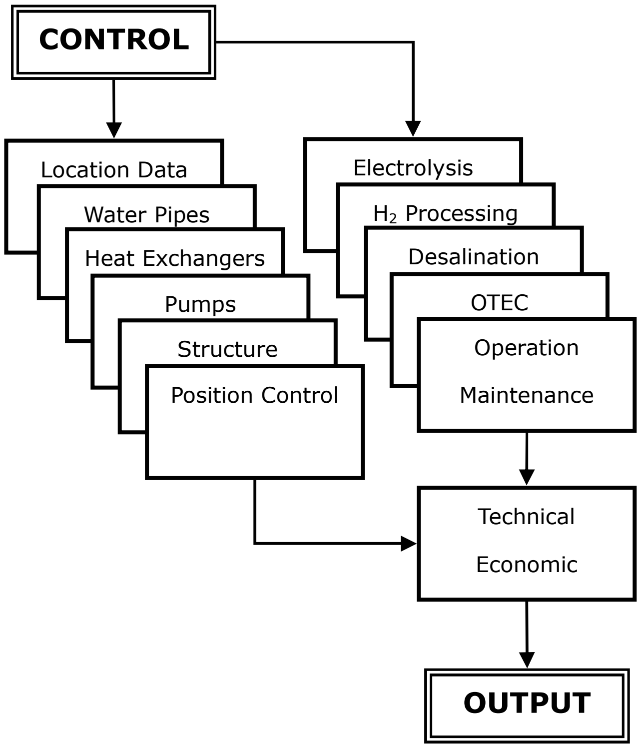

Fig. 2. Outline of OTEC-H_2 software modules

Control Module – This is the primary user interface. The user can control variables such as product type, production rate, storage time, intake depth, pipe material and water velocities.

Location Data – This module is responsible for supplying the model with location-specific ocean depth-temperature profiles. The user can define a geographic location for the OTEC plant, and the module will reference stored temperature-depth profile data accordingly. Reference data has been accumulated from [8] and other temperature studies.

Water Pipes - Enormous water pipes and a substantial pumping effort are required for an OTEC plant to utilize the temperature difference between cold, deep ocean water and warm surface water. The huge volume of cold water demanded by the OTEC system requires a very large diameter pipe extending from a surface or near-surface platform to a considerable depth (~500 to 1500m). The water pipe module performs computations (based on user selections and stored reference data) pertaining to flow rates, pipe sizing and costing. This module performs cost estimation based on material costs, fabrication costs and overall sizing of the pipe. The parametrics are derived from basic structural and hydraulic analysis combined with material properties, material costs and cost data from previous Cold Water Pipe and OTEC projects [9-13].

Heat Exchangers – The hydrogen production demand, unit efficiency, capital cost, weights, volumes and areas are used to compute the cost, size and weight of this subsystem. Corrosion and bio-fouling considerations are influential to the selection process. Studies indicate there are several possible heat exchanger materials and configurations suitable for seawater applications [14-16]. Makai has worked many years with major heat exchanger manufacturers to quantify component costs and understand the implications of using heat exchangers in seawater applications.

Pumps –The general configuration of a high-efficiency pump is a function of operating point flow and head. The tremendously large water flow rate and low head OTEC seawater pump operating characteristics lead directly to the choice of an axial flow propeller type unit or a mixed flow type unit. Several pump manufacturers were contacted who furnished technical information and budgetary quotes to quantify pump costs.

Structure – This module is concerned with modeling the seagoing structure(s) designed to accommodate the OTEC operation. Data was collected relative to the cost and configuration of present large bulk carriers, tankers and mobile offshore bases). A framework for structure cost is developed as a function of useful weights and volumes. The various sub-systems of the OTEC plant are then fitted within this framework to derive a cost. The latest generation of Spar-type off-shore platforms (such as from Kerr-McGee) bear a remarkable resemblance to OTEC plants.

Position Control – By the nature of OTEC, the plant must be located in the deep ocean and may be subjected to undesirable wind and wave loadings. The model permits selection of the OTEC plant operating as a moored platform or as a dynamically positioned grazing plant. Either selection uses appropriate cost parametric data derived from previous OTEC system economic studies and recent OTEC projects. Grazing is considered to be more flexible, and gives the plant freedom to navigate to temperature-optimal ocean locations. From an economic perspective, use of a grazing plantship reduces the initial capital expenditure for mooring equipment but produces slightly less net power. This analysis used grazing as the position control technique.

Electrolysis – The electrolysis module simulates the processes and costs associated with hydrogen-producing electrolysis. The largest and most cost-affective electrolyzers currently in use today are of the alkaline bipolar type. Other potential types would be the uni-polar type or Solid Polymer Electrolyte (SPE) electrolyzers. The module is constructed with sufficient flexibility to allow consideration of various scenarios such as future low capital cost SPE electrolyzers vs. current-day alkaline bipolar type. For modeling purposes, the capital cost of current day electrolyzers was assumed to be $1000/kW compared with a future capital cost of $125/kW [17-18].

H2 processing – Low pressure hydrogen gas must be either compressed or liquefied to create a fuel with an adequate energy density. Both processes require energy and equipment which are modeled by this module. It is estimated that compression of hydrogen has an associated energy penalty of 4-8% and liquefaction has a 40% energy penalty [18]. Ammonia is produced by reacting the hydrogen with nitrogen obtained from an air separation unit.

Desalination - Fresh water is needed for the electrolyzer. This module analyzes the required flows and determines the volume and weights required.

OTEC – This module calculates the electrical power generation by means of a low temperature Rankine cycle. The OTEC equipment consists of the turbines, refrigerant working fluid, pumps, pipes, valves, tanks, generators, instrumentation and controls. Aspects of the Rankine and more complicated Kalina and Uehara cycles are considered [13]. The governing variables for maximum power output are: warm and cold water temperatures, warm and cold water heat capacity rates (mass flow times heat capacity of the water), and the evaporator and condenser sizes.

Operation and Maintenance – This module accounts for the cost and logistics of running the OTEC plantship. A uniform labor rate of $1200 per person per day is used.

Technical and Economic - The economic module uses analytical procedure developed by the Electric Power Research Institute in their Technical Assessment Guide (TAG) [19]. The TAG model is an economic analysis method of comparing a postulated alternate energy system against other conventional energy systems with different, but proven, capital and operating costs. The levelized (lifetime) cost of fuel production is computed by the TAG model. This model can be used to determine the same levelized price for competing technologies – and a fair cost comparison can then be made.

Transport and Logistics - Costs are based upon world shipping rates using research performed by Makai. Liquid Natural Gas (LNG) tanker rates are used for liquid hydrogen, new Compressed Natural Gas tanker rates are used for compressed hydrogen, and Liquid Petroleum Gas (LPG) tanker rates are used for ammonia, which is the current practice. These costs are not based upon Jones Act shipping rates so they are probably not conservative. Assuming the same hydrogen shipping breakthroughs discussed earlier, shipping costs constitute a small part of the total system cost in the model.

C. *Optimizing the modeled OTEC plant*

Numerous OTEC parameters are readily controllable by the user. The parameters evaluated are summarized in Table 2. We varied several key parameters to establish an optimized baseline design, as discussed in this section. The key parameters first evaluated were cold water vs. warm water flow ratio, Cold Water Pipe (CWP) intake depth and seawater velocity inside the CWP. These parameters are listed in Table 2. Once these key parameters were roughly optimized to serve as a baseline OTEC system, simulations representing various logical scenarios were run, as presented later.

Fig.3. shows that the cost of electricity from a 100 metric tons-per-day (tpd) OTEC plant varies as the ratio of warm water to cold seawater changes. On a purely thermodynamic basis, nearly equal seawater flows should be optimal. But the high cost of the cold water pipe favors using 1.6 times more warm seawater (via short and inexpensive piping) to provide the same temperature differences. The minimum selected price represents the optimum configuration.

The velocity inside the cold water pipe is a variable that can be optimized. Higher velocities in the CWP mean that the CWP can be made smaller which minimizes capital cost. We anticipated that this capital savings would be penalized by a larger need for pumping energy. Instead, our model shows there is a relatively weak function between seawater velocity and friction losses because the pipes are large compared to typical civil works. The model suggested that the optimum CWP velocity is faster than 6 m/s. We concluded that other factors such as piping manifold layout would be important and used a maximum CWP speed of 4 m/s.

TABLE 2: KEY PARAMETERS OF OTEC PLANTS

Parameter	*Range*	*Description*
CW:WW flow ratio	1.2 - 2.8	Ratio of warm water & cold water affects plant efficiency & capital cost.
CWP intake depth	500-1500m	Deeper water is colder so process is more efficient – but greater CWP cost.
CWP velocity	2-6m/s	Faster speed in the cold water intake pipe uses smaller pipe but more power.
Product	H_2(l), H_2(g), NH_3(l)	3 products analyzed: Compressed or liquid hydrogen, & liquid ammonia.
Plant Size	25-200 tpd	Plant size in terms of metric tons of hydrogen produced per day.
Location	W. Pacific E. Pacific W. Atlantic	Plant location governs ocean temperature profile & shipping cost.
Financing	4 - 18%	OTEC is very capital-intensive, system economics are sensitive to finance rate.

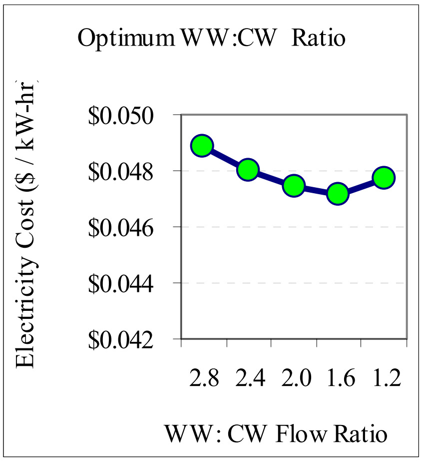

Fig. 3. Optimum ratio of warm seawater vs. cold seawater is 1.6.

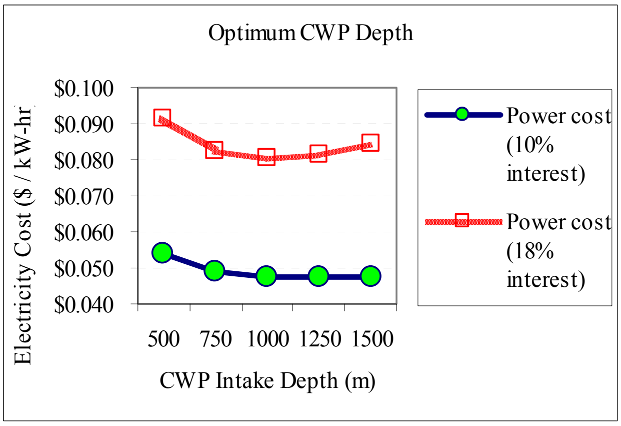

Fig. 4. Optimum cold water pipe depth. For 10% interest rate, the optimum CWP depth is 1250m. At 18% interest, the higher finance charge favors the less expensive 1000m CWP.

OTEC MODEL RESULTS

A. Baseline Future OTEC Economics

As a baseline, a 100 tpd liquid hydrogen OTEC plant was selected. Major components, costs and parameters are summarized in Table 3. The material and energy balance data were taken directly from the model. A design life of 20 years was used to permit comparison with alternative hydrogen producing technologies [20, 21] that also use 20 years. For an OTEC plant, this is probably a conservatively short life. A production level of 92% capacity is assumed to allow for maintenance, repairs and extreme weather. One example of such a system (possibly comprised of two major components so that product type can be changed) is shown in Fig. 5. It should be noted that the OTEC cost model is actually based upon the more extensive literature available for large ship-like vesssels.

B. Scenarios Considered

We organized the simulations into a family of scenarios because of the many technical and financing variables involved with modeling the system, logistics and financing for an OTEC fleet. For this paper we explored five scenarios relating to plant production rate, location, type of product and financing rate.

TABLE 3: NOTIONAL 100 TONNES H_2 PER DAY OTEC PLANT

Parameter	*Baseline*		*Subsystem*	*Cost ($ Million)*
CW:WW ratio	1.6		Electrolysis	$24M
CWP depth	1250m		Liquefaction	$113M
CWP diameter	10.5 m		Water Pipes	$90M
Product	Liquid H_2		Water Pumps	$57M
Plant Size	100 tpd		OTEC Process	$247M
Location	E.Pacific		Structure	$174M
Financing	10%		Total	$708M
WW Temp	28.4°C		WW Flow	553 m^3 / sec
CW Temp	3.6°C		CW Flow	346 m^3 / sec
Net Power	235 MWe		Displacement	471,000 mT
Electric Cost	4.6¢/kWhr		Rankine Eff.	80%
H_2 Volume	1413 m^3/d		Electrolysis	46.4 kWhr/kg H_2

Plant Production Rate – Plant sizes capable of producing 25, 50, 100, 150 and 200 tpd of hydrogen were modeled. As expected, OTEC displays a significant economy of scale as shown by Figs. 6 & 7.

Product Produced – For the same production rates, we considered plants that would create compressed hydrogen, liquid hydrogen, and ammonia. In general, the costs of liquid and compressed hydrogen are similar, with the benefit of the more-easily-shipped liquid hydrogen balanced by the cost and volume of the liquefaction equipment. Sending hydrogen to shore as ammonia provides the lowest cost, but ammonia is presently not a product envisioned for the hydrogen economy.

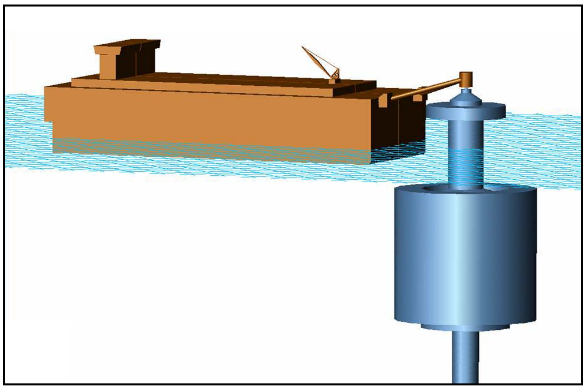

Fig. 5. Image of a spar-like OTEC electrical facility supplying an FPSO that produces and stores ammonia or other marketable energy product.

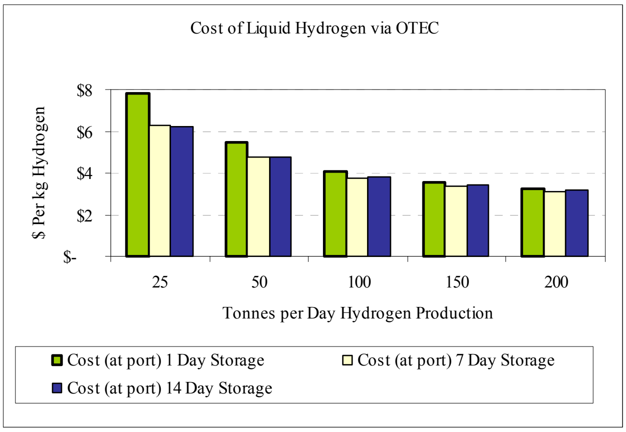

Fig. 6. Cost of liquid hydrogen in the future shows economy of scale for large OTEC plants.

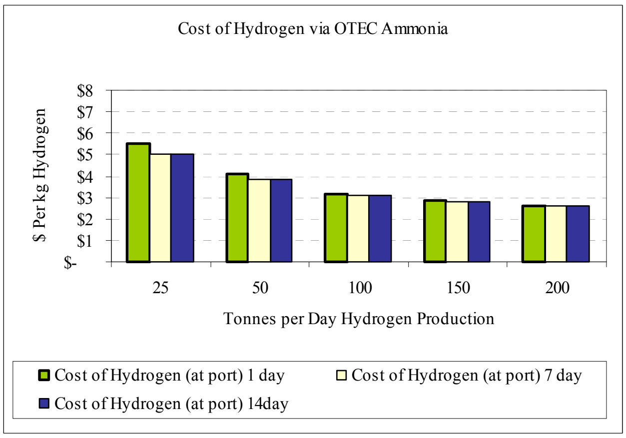

Fig. 7. The general price trend for future ammonia OTEC plants is similar to liquid hydrogen plants, but the overall delivered cost is less.

Storage - We investigated the benefit of storing 1, 7 or 14 days of product on the plantship prior to offloading to the product tanker. The potential benefit of additional storage is fewer transfer operations, while the drawback is that the plantship must be larger. Our modeling suggests the cost differences between 7 or 14 days of storage are rather slight.

Location – For a 100 tpd hydrogen plant, we evaluated the delivered cost of ammonia for three different grazing locations of the OTEC plantship fleet. These locations are shown in Fig. 8 and are termed west Pacific Ocean (assumed to be centered at latitude 139.5°East, longitude 9.5°North), east Pacific Ocean (100.5°W, 12.5°N), and west Atlantic Ocean (47.5°W, 4.5°N). The warm and nearby east Pacific grazing area provides the lowest-cost hydrogen (carried by ammonia) at a cost of $3.07 per kg H_2. The warmer but more distant west Pacific grazing area cost is nearly the same, $3.08 per kg, and the west Atlantic site costs 8% more.

Financing Rate – Using the model, we varied the OTEC plant's book life and interest rate. Fig. 9 shows the price of OTEC liquid hydrogen at an interest rate of 4%, 10% or 16%, assuming a 20-year book life. For simplicity, rates for bonds and equity are considered to be the same. An interest rate of 4% would represent significant government support, 10% was used for our baseline analysis, and 16% would constitute an excellent return on investment. Lengthening the book life decreases the cost of hydrogen but is less significant that altering the interest rate.

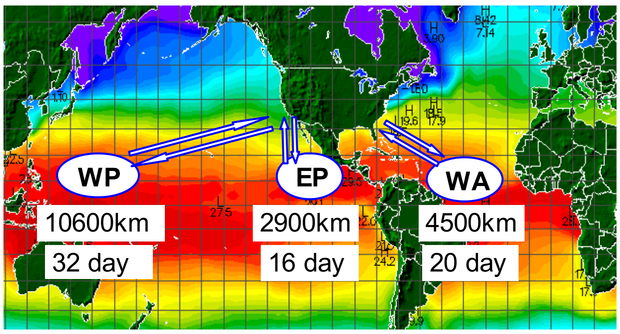

Fig. 8. One-way distance & round-trip cycle time for vessels servicing numerous OTEC plants (each with 14-day storage) in the Western Pacific (WP), Eastern Pacific (EP) or Western Atlantic (WA) Ocean. Warm sea surface temperature is shown as red on this image [22].

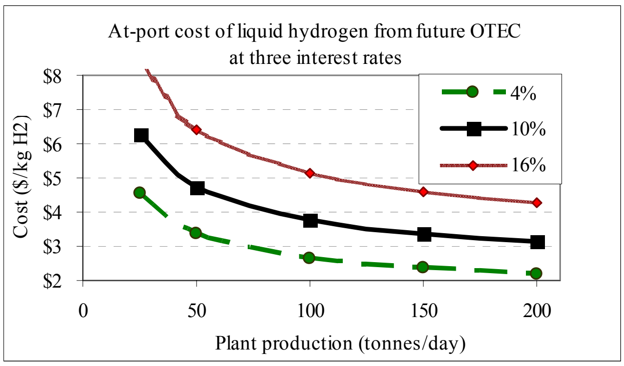

Fig. 9. Cost of hydrogen synthesized at future eastern Pacific plantships financed at three different interest rates.

OTEC & OTHER FUTURE HYDROGEN SOURCES

A. Hydrogen source cost comparison

Fig. 10 shows estimated production and delivery costs to a nominal hydrogen filling station using hydrogen from six possible future sources. Costs other than OTEC are based upon Figure 5.3 and Appendix E from [5] and have been adjusted to include $1/kg hydrogen delivery or 3¢/kWhr electricity distribution cost to permit direct comparison.

The cost of hydrogen from "Coal" is based upon coal gasification with CO_2 sequestration at a large 1,200 tonnes/day H_2 plant. The cost of hydrogen from nuclear fission ("Nuc") is based upon a not-yet demonstrated nuclear thermal water-splitting technique to efficiently produce hydrogen gas. The cost of bio-mass hydrogen ("Bio") is based upon a 24 tonne H_2/ day gasification plant. The cost for electrolyzed hydrogen from distributed wind turbines ("Dist Wind") assumes 4¢/kW-hr electricity from wind turbines plus 3¢/kW-hr distribution costs powering low-cost ($125/kW) future electrolyzers that furnish 1.2 tonne per day compressed hydrogen to a filling station. The cost for distributed solar photo voltaic electrolyzed hydrogen, ("Dist Solar"), assumes 9.8¢/kW-hr electricity from wind turbines plus 3¢/kW-hr distribution costs powering low-cost ($125/kW) future electrolyzers that furnish 432 kilograms per day to a filling station.

The cost for Hydrogen from OTEC is based upon Makai's OTEC economic model for 200 tonnes /day plants using $125/kW future electrolyzers and 14-day onboard storage delivering liquid hydrogen to port for $3.74/kg, plus $1/kg for delivery cost. A 14% interest rate and undefined (infinite) book life is used to match the calculations in [5] for distributed wind and solar. The model predicts this large plant will displace 744,000 tons with a capital cost of $1.2 billion.

B. Other hydrogen source considerations

Fig. 10 suggests that the hydrogen economy will probably be supplied by coal gasification or nuclear power because they are the lowest cost. Unfortunately, there are no easy answers. Massive coal gasification assumes the risk that its accompanying carbon dioxide can be sequestered with environmental safety at a competitive cost. Likewise, the long-term storage of radioactive nuclear waste creates a persistent risk for many generations. Both methods generate emissions that must remain safely stored for timeframes that exceed those of the empires that guarantee their safe-keeping.

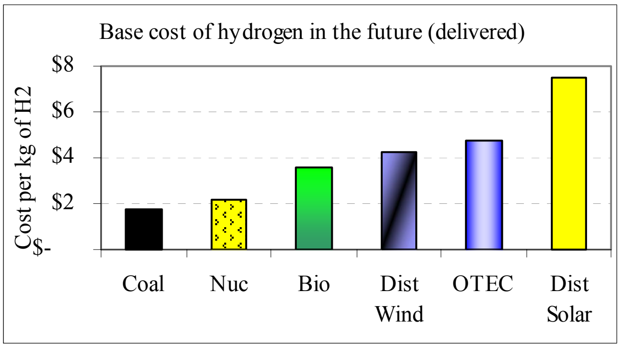

Fig. 10. Future costs to provide hydrogen to a filling station.

Of the renewable technologies, biomass has the lowest cost. If the hydrogen needed for vehicles in 2050 were generated by biomass, the land requirement would be 33% of U.S. cropland [5]. This large diversion of productive land will be competing with a larger U.S. population needing both land and food. Uncertainties still exist that the overall biomass process system can yield significantly more than the input energy used to fertilize, harvest, ship and dry the feedstock switchgrass. The nation's long experience with subsidized ethanol still shows no net reduction in imported energy [23].

Wind turbines, if ideally situated in class 3 wind zones such as North Dakota, would require approximately 2.3% of the land area within the continental United States [5, 24]. One reason wind turbines use a large land area is because wind is an intermittent energy source. Table 1 shows that the annual capacity factor for wind is 0.39 compared to nuclear electrolysis. Also, not all the turbines distributed throughout the U.S. will experience ideal conditions, further increasing land usage. The resulting ubiquitous wind turbines would dominate the landscape of all U.S. towns and compete with other land uses.

Solar photo-voltaic would cost more than OTEC, but may be helpful in regions with low population and high solar insolation. Based on Table 1, solar's annual capacity factor is 0.29 compared to nuclear electrolysis.

Table 4 illustrates these diverse aspects of hydrogen supply methods. Three additional categories, pollution risk, technical/cost risk and resource limits are given a score ranging from "1" (good) to "3" (bad).

Coal gasification is based upon a finite resource and has pollution risks, but it is the least expensive. If proven, nuclear thermo-chemical water-splitting seems attractive except for its potentially catastrophic risk. Biomass may be a non-polluting method, but is land-intensive and unproven. Distributed wind seems quite attractive since it uses well-developed and non-polluting technology, although cost and land issues will be a challenge. OTEC seems attractive because although slightly higher cost than wind, it does not compete for land. Distributed solar is sustainable but costs significantly more than the other methods.

Other methods used to compare energy carriers, such as net energy efficiency and CO_2 release, give favorable scores to OTEC.

TABLE 4: OVERALL HYDROGEN SOURCE MATRIX

	Coal	Nuc	Bio	Dist Wind	Otec	Dist Solar
Pollution Risk	3	3	1	1	1	1
Technical Risk	1	2	2	1	2	2
Resource Limits	3	1	3	2	1	2
Hydrogen Price / kg	1.8	2.2	3.6	4.2	4.7	7.5

A net energy ratio can be made to compare the energy produced during a hydrogen plant's lifetime with the energy consumed by all of the processes associated with building and operating the plant. (This second term is called the "embodied energy"). The net energy ratio for steam methane reforming into hydrogen is 0.7 (less than unity represents a net energy loss) and for wind / electrolysis is 13.2. [20 & 21]. Makai computed that the net energy ratio for OTEC is 38.2.

Values of CO_2 release range from the continuous high release rates of fossil fuels to other technologies such as wind turbines that release CO_2 only during manufacture. For OTEC, deep seawater brought from 1250m and returned to the ocean at 100m deep will achieve a new chemical equilibrium by outgassing a fraction of its dissolved CO_2. The quantity outgassed by a closed cycle OTEC plant is expected to be less than 0.3% compared to present day combustion techniques of the same power [25]. This minute quantity makes OTEC essentially a non-polluting technology.

AMMONIA OTEC USING EXISTING SUBSIDIES

Depending upon the outcome of the NAE's four pivotal questions, it will be 10-30 years (or perhaps never) until the hydrogen economy develops. One initial method where the U.S. can begin a shift to carbon-free domestic energy using present technology is to use OTEC-derived hydrogen to produce ammonia. OTEC ammonia would compete with ammonia made from foreign natural gas, reducing American dependence on imported energy.

The single largest worldwide use of hydrogen (25 million tonnes worldwide) is as an intermediate step in the production of 140 million tonnes of ammonia from natural gas. High natural gas prices in the U.S. are causing increased import of ammonia synthesized from low-cost foreign natural gas [26]. In 2004, the U.S. imported 6 million tonnes of ammonia, equivalent to 1 million tonnes of hydrogen, which represents one-eighth of U.S. hydrogen production. Ammonia is shipped worldwide using propane tankers – much simpler than shipping hydrogen.

We modified our baseline 100-tonne per day OTEC hydrogen model to include costs of the ammonia synthesis reactor vessels, nitrogen air separation unit, and 14-day storage. Electrolyzer purchase cost was increased to today's value of $1000 per kW [17] instead of the $125 per kW future value. Financing was modified to 5% interest and a 30-year design life and assumes that federal obligation guarantees, up to $1.65 billion have been obtained from the United States' OTEC Demonstration Fund [27]. Constructing such a plant seems within present offshore fabrication capabilities. Table 5 presents the costs of major subsystems of this plant.

The cost per tonne of ammonia with these parameters is $494 per tonne, as shown in Fig. 11. This price is 66% more than the current price of $297 per tonne for imported ammmonia [28]. One or two decades in the future, it is quite conceivable that ammonia from natural gas would cost the same as ammonia from OTEC.

A tax credit of 1.9¢ per kWhr for renewable energy production [29] presently exists. If this tax credit is applied to ammonia production, the cost for "Subsidized OTEC 2010" ammonia becomes a nearly competitive $335 per tonne. This subsidized cost would be competitive if natural gas costs increase 13%.

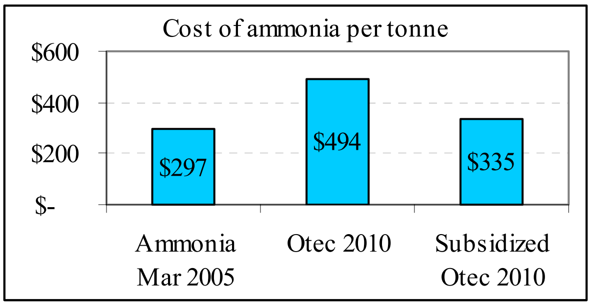

Fig. 11. Present ammonia price FOB Tampa compared with unsubsidized & subsidized ammonia from OTEC using today's technologies.

TABLE 5: OTEC AMMONIA PLANTSHIP SUBSYSTEM COST

OTEC Subsystem	*Cost ($Million)*
Electrolysis	$193M
Ammonia Production	$61M
Water Pipes	$83M
Water Pumps	$53M
OTEC Process	$230M
Structure	$168M
Total	$786M

CONCLUSIONS

This study developed a technical and economic model for Ocean Thermal Energy Conversion plants supplying a widespread hydrogen economy. Upon comparing the results with other potential hydrogen sources, it's clear that no source is ideal but OTEC is attractive overall. Momentous choices must be made.

- Major technical breakthroughs, especially for hydrogen storage, are needed for the hydrogen economy to evolve.
- With these breakthroughs, OTEC hydrogen will cost slightly more than biomass gasification and wind turbine electrolysis, but significantly less than solar photo-voltaic electrolysis.
- Coal gasification and nuclear thermochemical splitting with CO_2 or nuclear waste sequestration will cost the least. Both entail technical risks and bequeath humankind with potentially catastrophic stored waste.
- Massive-scale biomass and wind energy will displace limited land resources used for farming and living. Massive-scale solar energy is the highest cost option.
- OTEC is the most sustainable massive-scale energy source. It is the only source that uses non-intermittent solar energy, and it does not use land.
- Ammonia created using OTEC with present technology could reduce foreign energy imported in the form of ammonia. OTEC ammonia with subsidies is within 13% of the present ammonia market price.

OTEC is both a technically and economically viable hydrogen production pathway for delivery of massive quantities of energy; it is cost competitive with other renewable technologies and it is environmentally sustainable. OTEC should be considered a legitimate player in the envisioned hydrogen economy but ironically it is barely mentioned today in hydrogen economy documents. The US and the world are on a path towards a non-oil-based future and the decisions ahead are momentous. As a minimum, OTEC, which is low-risk and environmentally sustainable, should be developed in parallel with those other technologies that appear to be economically attractive but have significant environmental risks attached. Technically, environmentally and economically – not considering OTEC is a risk the world can not afford to take.

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