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Quarterly Report

OCEAN ENERGY SYSTEMS

at The Johns Hopkins University Applied Physics Laboratory

JULY – SEPTEMBER 1982

THE JOHNS HOPKINS UNIVERSITY • APPLIED PHYSICS LABORATORY

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THE JOHNS HOPKINS UNIVERSITY ■ APPLIED PHYSICS LABORATORY
Johns Hopkins Road, Laurel, Maryland 20707

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FOREWORD

The Applied Physics Laboratory issues the *Quarterly Report* series to provide the defense establishment and the scientific community with current awareness of selected APL activities. At present, the *Quarterly* consists of the following volumes:

Programs	Report Designators
Department of Defense Programs	
Research and Development	RQR
Exploratory Development for Missile Propulsion	DQR
Civil Programs	
Ocean Energy Systems	OQR
Biomedical Research, Development, and Engineering (Annual Report)	MQR

The nomenclature for the APL *Quarterly Report* is as follows. The designation for *Quarterly Report*, "QR," is preceded in each case by a letter that indicates the volume's program area. After the "QR," a virgule is followed by a year indicator (e.g., "82-") and a number from 1 to 4 to specify the calendar quarter.

The format is designed so that most technical articles can be presented on a single sheet of paper. Each article is given a section number (e.g., §24), which applies to the current *Quarterly* only. Each article is keyed to its major program area (e.g., Research and Exploratory Development), its technical instruction (e.g., Amorphous Semiconductors), its budget code (e.g., A3), the Laboratory Group or Groups that performed the work (e.g., BBE), and the agency that supported it (e.g., SEA-62R).

Certain Laboratory programs, including some that report a portion of their activities through the *Quarterly Report*, use document series other than the *Quarterly* to report the bulk of their activities. Those series are available only to individuals and organizations that are directly concerned with the specific programs involved.

Requests for *Quarterly Reports* should be directed to: Supervisor, Technical Publications Group, Applied Physics Laboratory, Johns Hopkins Road, Laurel, Maryland 20707.

PREFACE

The Johns Hopkins University Applied Physics Laboratory, under a contract with the U.S. Department of Energy's Division of Ocean Energy Technology (DOE/DOET), is engaged in developing Ocean Thermal Energy Conversion (OTEC) systems that will provide synthetic fuels (e.g., methanol), energy-intensive products such as ammonia (for fertilizers and chemicals), and aluminum. The work also includes assessment and design concepts for hybrid plants, such as geothermal-OTEC (GEOTEC) plants. APL has been designated the Lead Laboratory in these areas by DOE/DOET. Another effort that began in the spring of 1982 is a technical advisory role to DOE with respect to their management of the conceptual design activity of the two industry teams that are designing offshore OTEC pilot plants that could deliver power to Oahu, Hawaii. In addition, the Laboratory is now taking part in a program in which tests of a different kind of ocean-energy device, a turbine that is air-driven as a result of wave action in a chamber, are being planned. This *Quarterly Report* summarizes the work on the various tasks as of 30 September 1982.

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OCEAN THERMAL ENERGY CONVERSION §1
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Dennis Richards **July-September 1982**

OTEC PILOT PLANT CONCEPTUAL DESIGN REVIEW

The Department of Energy, Division of Ocean Energy Technology (DOE/DOET) has awarded two contracts for conceptual designs of OTEC 40 MW pilot plants, both at Kahe Point, Hawaii, and has set up an OTEC Pilot Plant Program Management Office with Carmine Castellano as Program Manager. The Energy Technology Engineering Center (ETEC) of Rockwell International is the Technical Support Contractor providing management and coordination support. APL has been designated as a Technical Advisory Laboratory as have the National Oceanic and Atmospheric Administration (NOAA), Lawrence Berkeley Laboratory (LBL), and Argonne National Laboratory (ANL). A working group, formed by DOE/DOET, will monitor progress on the two contracts; APL is participating as a member of the group.

SUMMARY

Following the contract awards to the General Electric Co. (GE) and Ocean Thermal Energy Corp. (OTC) in the previous quarter, the conceptual design effort of each of the contractors began, with preliminary results reported for the period of June to September 1982. The structuring of the design effort is based on the requirements stipulated in the Program Opportunity Notice Solicitation, whereby major reporting and DOE program management and Technical Advisory Laboratory (TAL) reviews occur at approximately 3 month intervals. The reporting document submissions are divided into sections for initial, interim, draft final, and final reports, as indicated in Table 1 of Ref. 1.

The limited preliminary design period (1 year contracts) and the necessary fast review response were the subjects of some discussion; reports are now mailed directly to each TAL. Review comments are returned to ETEC, the program manager and management support contractor, generally within 2 weeks.

Coordinated review comments are returned to the contractor for disposition response as:

1. Comment to be factored into performance of work and/or into next report.
2. No action required (resolved, not required by contract) or having significant cost impact.
3. Requires study – assigned action item (An action item list is maintained whereby unresolved questions are assigned to specific program participants for resolution.)
4. Contractor response or resolution.

As expected, the initial reports received for review were somewhat limited and were mainly extracted from the GE and OTC proposals. Thus review comments were generally directed to what might be expected in the developing designs. The designs generally are in accord with the descriptions contained in Ref. 1. Major differences at this time are discussed in the following sections.

DISCUSSION

OTC. The island concept, now apparently favored, places the plant in deeper (~ 50 ft) water approximately 1800 ft from the shoreline, with a precast concrete pile trestle bridge to shore in place of the original causeway. The trestle should eliminate sand entrapment, beach build-up, and alteration of near-shore current effects that could have affected both the existing Hawaiian Electric Co. (HECO) plant cooling water intake and the OTC-OTEC plant warm surface water intake. Initial studies indicated that the plant could be designed to withstand the maximum design (100 year storm) wave or a tsunami wave at the new location, although further investigations are necessary. A major advantage in moving the plant further offshore is the shortened length (and hence costs) of the nominal 30-ft-diameter cold water intake and the two mixed discharge outfall pipes, as against the increase in length of the smaller diameter HECO warm water discharge pipe. Overall total cost estimates are still tentative.

GE. Some further development of the platform design concept was shown, including cold and warm water piping and heat exchanger layouts. A change in the working fluid to be used (from R22 to NH_3) is being studied. The major change is a proposed single 60 MW (gross) turbine-generator in place of the 4 - 14 MW units of the original concept.

The confidentiality agreements and competitive proprietary designs prevent discussion of many details of these designs and our review comments until open publication is permitted.

Table 1 lists the design contractor deliverables in itemized order and the date APL review comments were returned to the program management office, generally within 21 days of the deliverable receipt. The most extensive comment and discussion by APL have been on the Cost Assessment and Commercialization Plans. Usually, at least two or more APL personnel have studied and provided comments on specific areas of the designs. It is apparent that the main Phase I Conceptual Design Review effort will come in the next two quarters. Additional deliverables on which some comment has been provided are listed in Table 2.

Design contractor presentation and DOE-TAL review discussion meetings have been tentatively

Table 1

Order of deliverables for OTEC pilot plant project.

Order No.	Item No.	Description	APL review response GE	APL review response OTC
1	7a	Initial report, Site Description	7-12-82	6-18-82
2	2a	Initial set, Design and Operational Data Sets	–	–
3	9a	Initial report, Cost Assessment	8-17-82	–
4	15a	Initial report, Preliminary System Interface Integration Criteria	–	7-26-82
5	3a	Interim report, Site Specific EA (Environmental Assessment)	–	–
6	5a	Initial plan, Required Permits and Licenses	–	–
7	6b	Interim report, Preliminary Safety Analysis Report	9-13-82	–
8	11a	Initial report, Operation and Maintenance Plan	9-13-82	–
9	12a	Initial report, Commericalization Plan	–	9-7-82
10	2b	Interim report, Design and Operational Data Sets	–	–
11	3b	Interim report, Site Specific EA		–
12	1b	Interim report, Conceptual Design of OTEC Concept		
13	2c	Draft Final Report, Design and Operational Data Sets		
14	7b	Interim report, Site Description		
15	8b	Interim report, Risk Analysis		
16	9b	Interim report, Cost Assessment		
17	11b	Interim report, Operational and Maintenance Plan		
18	12b	Interim report, Commericalization Plan		
19	13b	Interim report, Preliminary Test Plan Long Lead Item List		
20	15b	Interim report, Preliminary System Interface Integration Criteria		
21	3d	Final report, Site Specific EA		
22	4b	Interim report, Plan Site/Design Specific EIS (Environmental Impact Statement)		
23	10b	Interim Report, Physical Model Test Plan		
24	1c	Draft final report, conceptual Design of OTEC Concept		
25	4c	Draft final report, Plan Site/Design Specific EIS		
26	6d	Final report, Preliminary Safety Analysis Report		
27	7c	Draft final report, Site Description		
28	8c	Draft final report, Risk Analysis		
29	9c	Draft final report, Cost Assessment		
30	10c	Draft final report, Physical Model Test Plan		
31	11c	Draft final report, Operation and Maintenance Plan		
32	12c	Draft final report, Commericalization Plan		
33	13c	Draft final report, Preliminary Test Plan and Long Lead Item List		
34	15c	Draft final report, Preliminary System Interface Integration Criteria		
35	14a	Initial report, Technology Transfer Plan		
36	1d	Final report, Conceptual Design of OTEC Concept		
37	2d	Final report, Design and Operational Data Sets		
38	4d	Final report, Plan Site/Design Specified EIS		
39	7d	Final report, Site Description		
40	8d	Final report, Risk Analysis		
41	9d	Final report, Cost Assessment		
42	10d	Final report, Physical Model Test Plan		
43	11d	Final report, Operational and Maintenance Plan		
44	12d	Final report, Commercialization Plan		
45	13d	Final report, Preliminary Test Plan and Long Lead Item List		
46	14d	Final report, Technology Transfer Plan		
47	15d	Final report, Preliminary System Interface Integration Criteria		

Table 2

Additional deliverables for OTEC pilot plant project.

No.	SOW Reference	Description	Part or Item No.
A	IV-M-B-4-1	QA/QC plan	1
B	IV-M-B-4-2	Preliminary parts list	1
C	IV-M-B-4-4	Scaling analysis	1
D	IV-M-B-4-5	Strategic materials	12
E	IV-M-B-4-6	Strategic materials, identified lists, and sources	1
F	IV-M-B-4-7	Survivability requirements	1
G	IV-M-B-4-8	Analytical models, identify and validate	1
H	IV-M-B-4-10	Environmental issues/problems	3
I	IV-M-B-4-10–III-C	Environmental monitoring studies	3, 4, 5
J	IV-M-B-4-10–III	Design and operational criteria, plan, and future studies	2
K	Attach. C	Billing/invoices – Form 1034 (monthly)	
L	3-A-1	Management Plan – Form 537 (initial, as changed)	
M	3-A-2	Milestone schedule and status report – Form 535, (initial, as changed)	1, q
N	3-A-3	Cost plan – Form 533P	1
O	3-A-4	Manpower plan form 534P	1
P	3-A-5	Contract management summary report – Form 536 (monthly)	q
Q	3-A-6	Project status report (monthly)	
R	3-A-7	Cost management report – Form 533M (monthly)	q
S	3-A-8	Manpower management report – Form 534M (monthly)	q
T	3-A-9	Conference record (as required)	
U	3-A-10	Hot line report (as required)	

scheduled at 3 month intervals, generally in accord with the design phase reporting schedule. The first of these was held at the New York offices of OTC's parent corporation, Basic Resources Corp., on September 8 and 9, 1982; subsequent meetings are being planned by the program management office at locations to be determined.

The interim report deliverables are probably the last on which major review comments can affect the proposals by the contractors for the Phase II preliminary design because proposals for Phase II are due in the ninth month of Phase I. Reviews and comments on Phase I draft final deliverables are expected to take major effect in the initial phase of the preliminary design effort. The initial draft for a Phase II statement of work and comments and criteria for evaluation of the Phase II preliminary design proposals were developed and discussed at a program management meeting on September 21, 1982. APL subsequently transmitted the following recommendations to the Program Manager, Mr. Castellano.

In response to the discussions at the OTEC Pilot Plant Program Office Meeting on September 21, 1982, assuming continuity of the design development by each contractor in their Phase II proposal, criteria for the Phase II preliminary design evaluation should be based primarily on evaluation of the Phase I conceptual design submissions and will include the following items.

1. a. Completeness of description including assurance of constructability
   b. Completeness of reporting – deliverables
2. Degree to which the design is based on:
   a. Proven components
   b. Existing technology
   c. Unproven technology
3. Credibility:
   a. Of performance
   b. Of cost estimates
4. Validity of design features:
   a. Scale-up factors
   b. Repetitive plants – location
5. Environmental impact assessment:
   a. Near shore
   b. Offshore
6. Evaluation of commercial feasibility:
   a. Market – number of plants
   b. Economics – $/kW, mills/kWh
   c. Manufacture – value to the United States

If criteria 1 through 5 are satisfactorily met, criterion 6 would appear to require the largest weighting factor in evaluations for government support.

Also, key elements for preliminary design in the Phase II proposals would be adequate and described in sufficient detail to ensure that these items will be fully developed:

1. Proposed variation or changes to conceptual design
2. Optimization analyses for:
   2.1 Power plant – seawater systems
   2.2 Structural requirements and costs
3. Survivability, environmental loads
4. Design and construction program plan and organization
5. IM&R plan and requirement
6. Drawings in sufficient detail

FUTURE PLANS

As noted earlier, the major review effort for Phase I will come in the next two quarters and may include an APL review of Phase II technical proposals, dependent on the specifics of the proposal and the DOE Source Evaluation Board requirement.

In addition to particular studies and investigations that could result from design reviews (the action items noted above), specific evaluations and testing requirements were identified, for which schedule and cost plans are to be developed to start in the Phase II Preliminary Design (Ref. 2). These tasks include:

1. Gasket materials: Compatibility for in-service environment and requirments. Evaluation for strength, wear and tear resistance, compressibility-compression set-creep, dimensional stability, permeability, chemical and temperature stability, combustibility and combustion products, and projected life.
2. Seals: Evaluation, analyses of proposed seal designs for rotating or reciprocating equipment for in-service environment and requirements, including pressure, temperature, wear-take-up, misalignment, material compatibility-stability, permeability, leakage, and positive sealing (no motion) as well as evaluation of possible failure modes, effects, and hazards.

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1. Section 1, *Quarterly Report, Jan-Mar 1982,* JHU/APL OQR/82-1.
2. C. Castellano (DOE) Lett. to D. Richards (APL) (20 Jul 1982).

Support: DOE/DOET
W. H. Avery and D. Richards
July-September 1982

OTEC METHANOL

The use of slowly cruising plantships to produce synfuels and energy-intensive products makes the tropical oceans a virtually unlimited, renewable resource for world energy needs. The present program is part of a broad effort to identify and establish a priority for OTEC products and processes that can have significant effects on U.S. oil imports and electric power requirements in the 1990's and beyond. OTEC methanol is a particularly attractive candidate fuel because it can replace gasoline as a motor fuel and is the preferred fuel for high-efficiency fuel cells for power generation. In both applications, preliminary analysis indicates that costs will be comparable to, or possibly below, those projected for alternative energy sources.

SUMMARY

The conceptual design of a 160 MWe OTEC plantship has been documented; it is designed to produce 1000 metric tons/day of fuel-grade methanol from coal shipped to the plantship, using oxygen and hydrogen from the on-board electrolysis of water. Data and components are used that were derived by Brown & Root Development, Inc. (BARDI) in designing a plant to make methanol from natural gas for Litton Industries and in the design and construction of a coal-to-ammonia demonstration plant in operation at Muscle Shoals, Ala., for the Tennessee Valley Authority (TVA). The OTEC plant design is based on the use of the Texaco gasifier and Lurgi methanol synthesis units. The sale price of OTEC methanol delivered to port from this first-of-a-kind plant is estimated to be marginally competitive with methanol from other sources at current market prices. The preliminary evaluation of gasifiers using a molten salt bed combustion zone indicates that production economics can be bettered significantly. A final report is scheduled for publication in early December.

BACKGROUND AND DISCUSSION

Methanol synthesis from coal requires two basic processes: (a) the reaction of coal and oxygen to form carbon monoxide (CO), and (b) the reaction of CO with hydrogen to form methanol (CH_3OH). In conventional plant designs for methanol synthesis, oxygen is produced by air liquefaction and separation, and hydrogen by reaction of water with carbon in an endothermic process that consumes roughly half the carbon to provide the process heat. The availability of pure hydrogen and pure oxygen from water electrolysis on an OTEC plantship permits significant simplification of the methanol process equipment and twofold improvements in the output of methanol per ton of coal. Cost estimates indicate favorable economics compared to land-based production.

Initial evaluations of the process requirements for OTEC methanol were described in earlier reports of this series (Refs. 1 through 3). During the present quarter, effort has been concentrated on the work being done by BARDI under subcontract to APL to apply the engineering data developed in other programs to a conceptual design of a practical OTEC methanol plantship. Figure 1 shows a layout for a 160 MWe plantship that would produce 1000 metric tons/day of methanol.

In the BARDI effort, the aim was to develop a concept plantship design using available components and current technology in processes that are feasible today and to obtain real cost estimates from which the economics and processes can be evaluated. The resulting plantship size and process efficiencies and quantities, as shown in Fig. 2, are smaller than those of the April-June report but have not been optimized. The additional territorial requirement for a coal-to-methanol process plant, for instance, has led to a limit on the combined OTEC power-process plant capacity in order to stay within practical construction capabilities.

A block diagram of the system components is repeated from the last *Quarterly Report* (Fig. 3). Final estimates of the component requirements and total system cost are not available. Preliminary estimates indicate that the delivered price of OTEC methanol would be marginally competitive at current sales prices with methanol from other sources.

The process based on the Texaco gasifier has several drawbacks that could be alleviated by using different gasifier designs. A major factor is the presence of CO_2 in the exit gas from the gasifier in a weight percentage roughly equal to its CO content, resulting in carbon loss with excess O_2 requirements, although the excess heat of reaction provides more than enough heat to generate process steam to drive the compressor. The current process design also requires additional hydrogen (over that contained in the coal and from the OTEC electrolyzers), obtained via a partial gas stream shift reaction: $CO + H_2O \rightarrow CO_2 + H_2$, resulting in additional CO and O_2 losses.

A second deficiency is the presence of sulfur compounds in the gases; the sulfur must be removed by passing the entire gas flow through an acid-gas removal system prior to the methanol synthesis unit. The components of the systems are major items in the space requirements and costs of the plant. Finally, the use of a coal-water slurry as feedstock to the Texaco gasifier

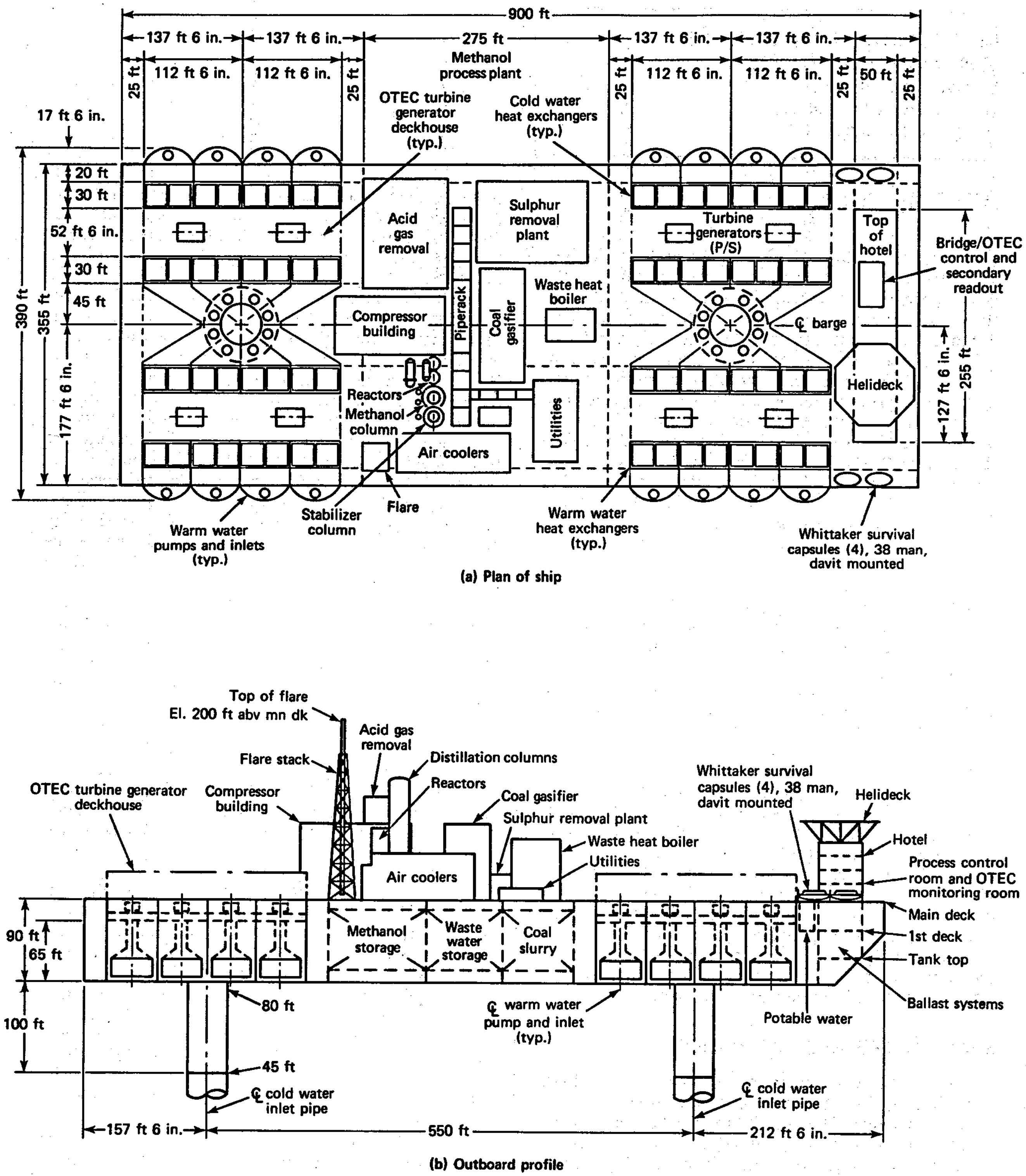

Fig. 1 Design layout for a 160 MWe plantship. (82-3/92)

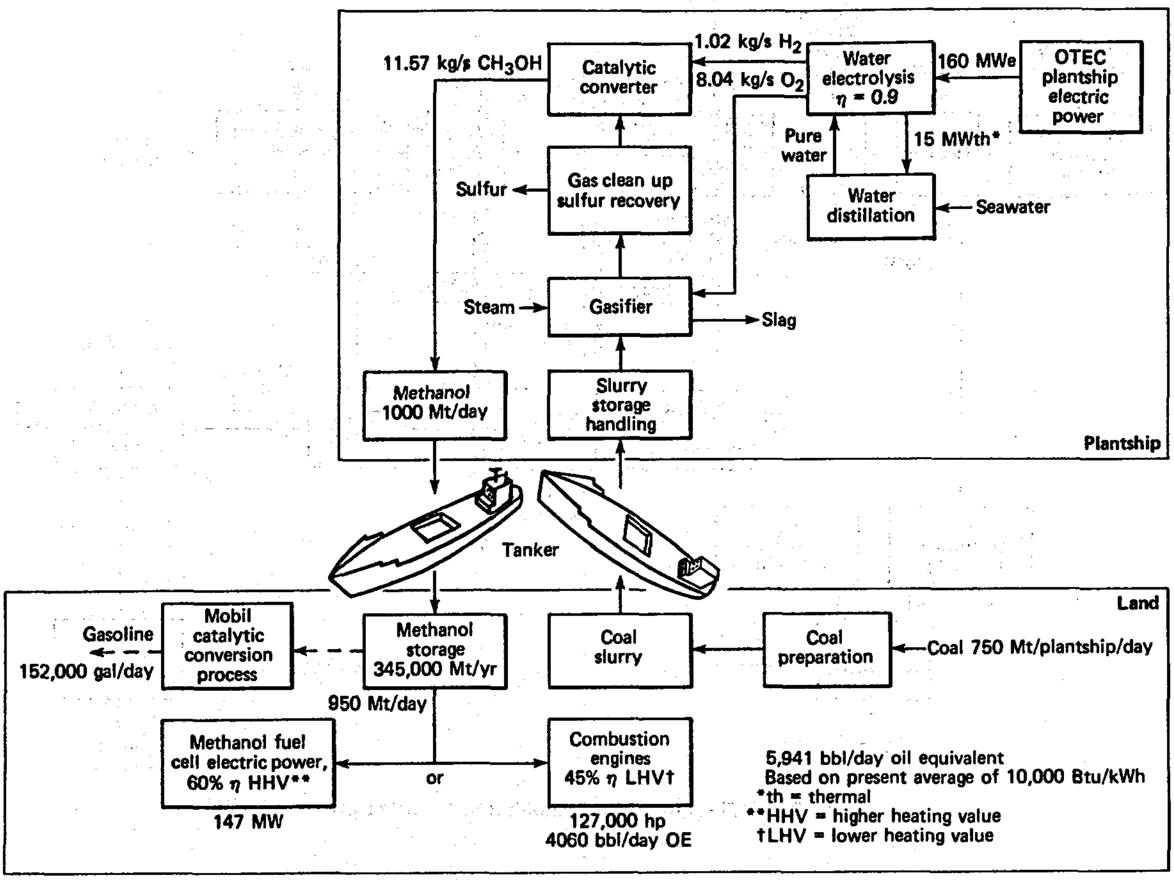

Fig. 2 OTEC plantship methanol process flow. (82-3/93)

leads to a requirement for a large and expensive waste water treatment plant that would necessarily be land based as would the coal-slurry preparation and transport loading facilities. In the present concept design, sufficient storage capacity is provided for a 30 day supply of coal slurry and for waste water (and slag), methanol product, sulfur by-products, and process chemicals. Waste water and gasifier slag would be removed on a 28 day cycle for on-land processing by the coal-slurry transport while methanol product, sulfur, and process chemical supplies would be transported by a product tanker on a similar cycle to a (probably) different geographical area. A possible scenario might be to supply Alaskan coal to a fleet of OTEC plantships operating about 1000 nmi south of Hawaii, with product delivery to Hawaii and California. Figure 4 shows the present concept, similar to existing designs developed for the North Sea, for the transfer of coal slurry, methanol products, and other chemicals via pipe connections over a hard-moor buoy, towing-trailing system accommodating relative motion between the plantship and the supply-product vessels.

In defense of selecting the Texaco system for evaluation, we should note the background of cost and operating experience by TVA and in German and British installations that permit reliable estimates to be made and provide a baseline for judging the value of improved systems. Data for the more advanced gasifier systems are available only for small experimental equipments (about 1 ton/h).

PROCESS OPTIMIZATION

Several gasifiers, which have been described in recent reports, produce a gas mixture nearly free from CO_2 (Refs. 4 through 7). Of these, the molten carbonate gasifier developed by Rockwell International appears particularly attractive for the OTEC plantship. Figure 5 is a schematic of this process. The feedstock is dry coal (ground to pass through a 1/4 in. mesh screen) that is pneumatically injected near the bottom of a bed of molten sodium carbonate (at 1800°F) along with oxygen and steam. Reaction is rapid, assisted by the catalytic action of sodium sulfide in the melt, and the emerging

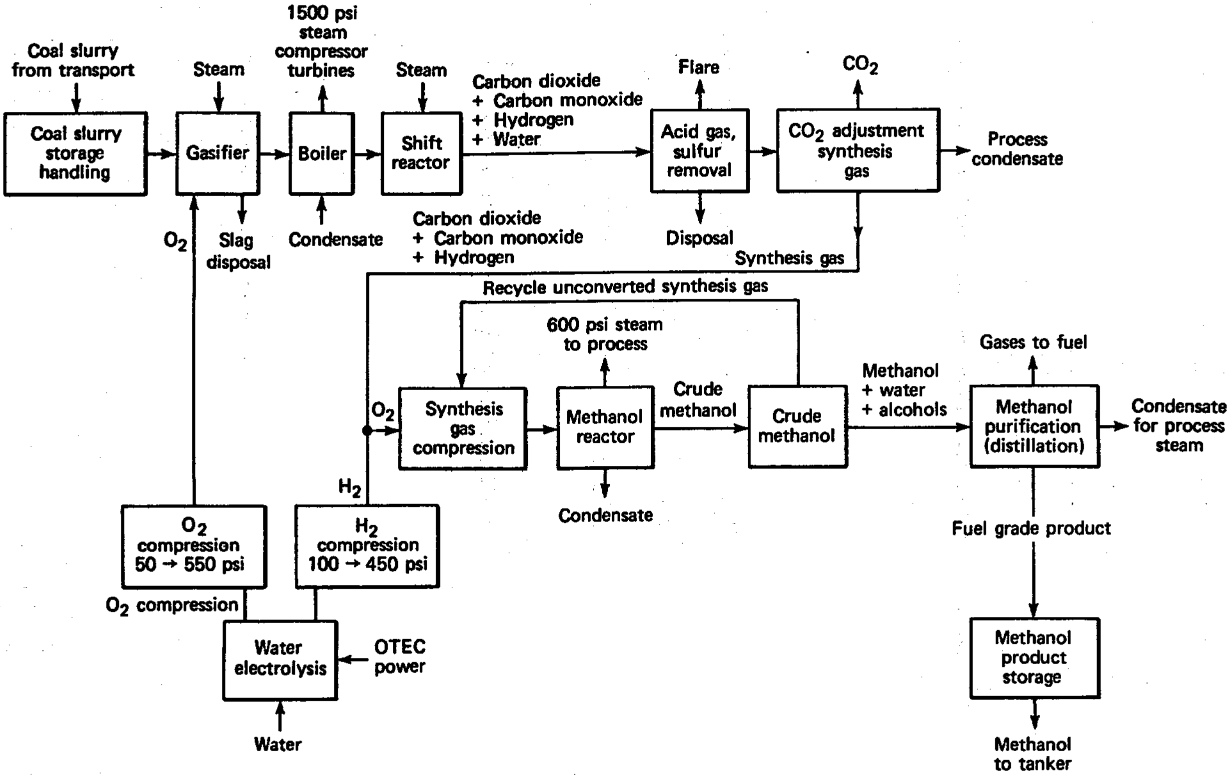

Fig. 3 Block diagram of methanol barge-mounted plant. (82-2/38)

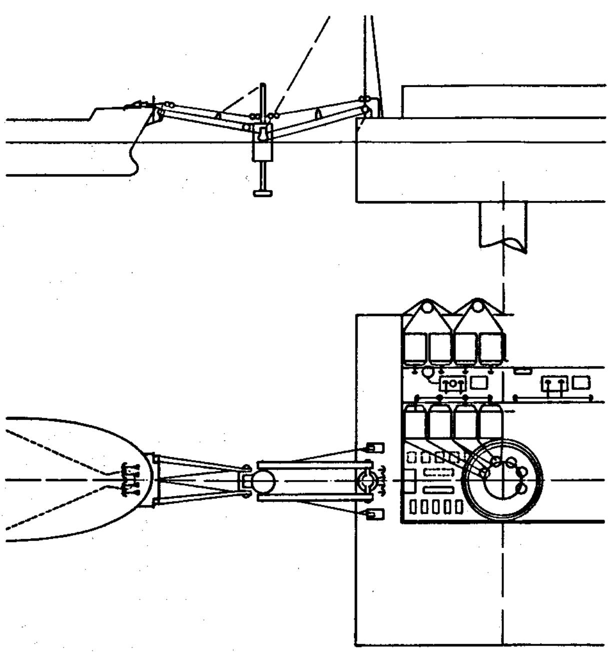

Fig. 4 OTEC plantship cargo transfer concept. (82-3/94)

gas is essentially at chemical equilibrium for the components carbon, oxygen, and hydrogen. Figure 6 is a schematic of the gasifier. As shown in Fig. 7, at equilibrium, the CO_2 content of the gas decreases rapidly to insignificant levels at temperatures above 1250 K (1790°F) at atmospheric pressure and is less than 10% of the CO mole fraction at pressures up to 25 atm at 1250 K. Sulfur in the coal reacts with the melt to form sodium sulfide; ash also dissolves in the melt so the exit gas is preponderantly a mixture of CO and H_2 in proportions determined by the ratios of oxygen, carbon, and hydrogen in the feedstock. The sulfur content of the gas is low enough (about 100 ppm) to permit the gas to pass directly to the methanol synthesis unit where it will pass through a guard section that removes the last traces of sulfur before entering the synthesizer.

It appears that substituting the Rockwell gasifier for the Texaco one would lead both to higher yield and to significantly lower methanol cost. The absence of CO_2 in the gas would require modification or replacement of the Lurgi synthesis unit to prevent temperature overruns in the catalyst bed. Other synthesis units (e.g., those developed by the Wentworth Co. and Imperial Chemical Industries) do not require CO_2 and could be used instead. An attempt will be made to quantify these process and cost improvements in the final report. The projected termination of funding will not permit engineering design calculations or a plant layout to be defined.

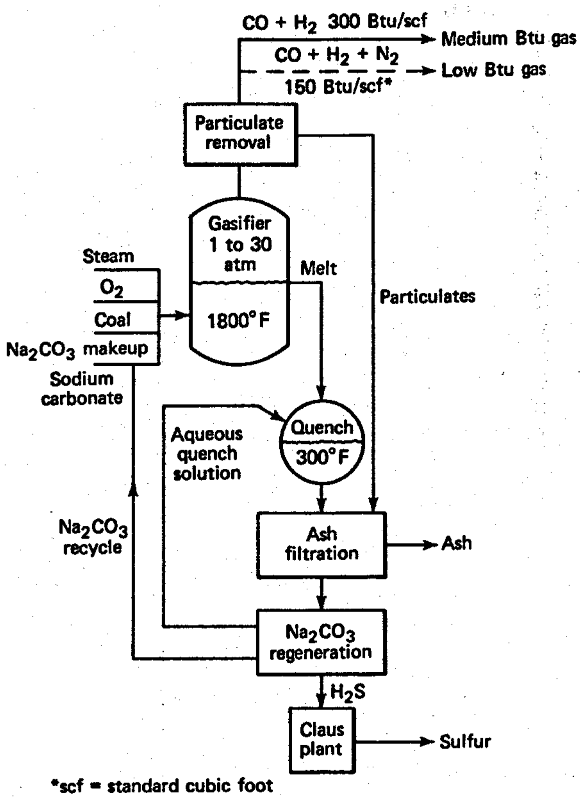

Fig. 5 Simplified flow diagram of molten salt coal gasification process. (82-3/95)

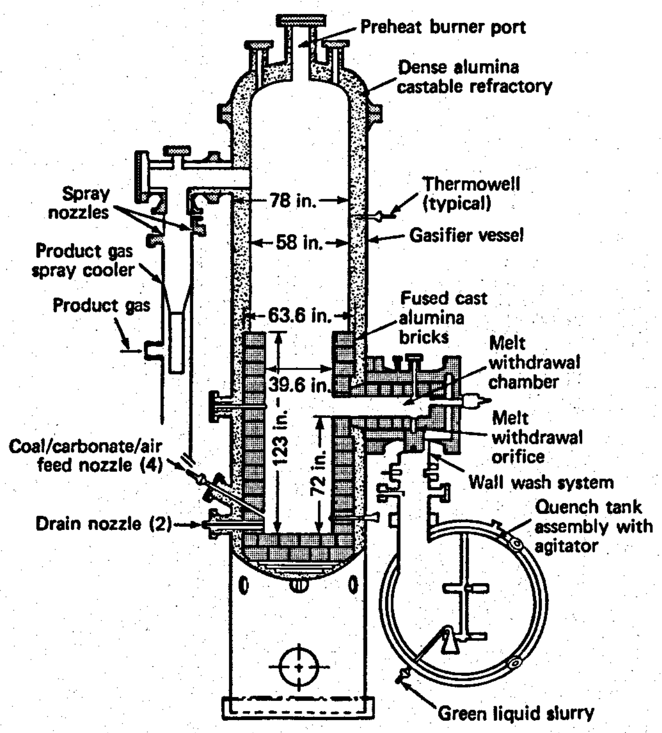

Fig. 6 Rockwell International process demonstration unit. (82-3/96)

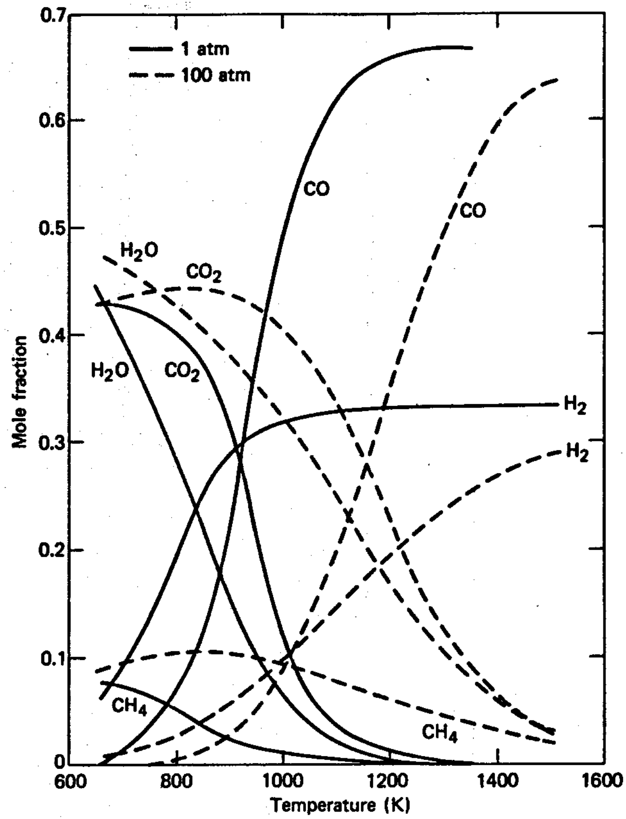

Fig. 7 Equilibrium characteristics for the carbon-hydrogen system (H/O = 1 g-atom/g-atom); solid curves, 1 atm; dashed curves, 100 atm (Ref. 8). (82-3/97)

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OCEAN THERMAL ENERGY CONVERSION	§3
Technical Assistance/Commercialization ZY3COE	
Support: DOE/DOET	
E. J. Francis	
July-September 1982	

FINANCIAL AND LEGAL CONSIDERATIONS IN OTEC IMPLEMENTATION

Technical development and engineering design studies in recent years have concluded that commercial OTEC plants and plantships will produce electric power and energy products at costs competitive with or lower than those for plants based on fossil fuel or nuclear power. However, suitable financial structures and legal and institutional mechanisms must be developed before industry will be able to proceed with the construction and operation of OTEC systems. The objective of work being done in this part of the APL program is to define the economic requirements for OTEC commercialization and indicate procedures that will facilitate the early growth of the U.S. industrial capability to produce OTEC plants and plantships in numbers large enough to make significant contributions to U.S. energy needs in the 1990's.

SUMMARY

Work during the quarter has included (a) the gain of additional insight into considerations by senior corporate management in evaluating OTEC construction within the context of their company objectives, (b) an update on the status of commercial OTEC projects, (c) the effects of the 1982 tax act and potential legislation, and (d) an understanding with the insurance industry of their willingness to underwrite OTEC risks.

MANAGEMENT CONSIDERATIONS IN UNDERTAKING OTEC CONSTRUCTION

The technical development and testing of components and the engineering design of complete large-scale OTEC demonstration vessels, including 100-yr storm survival tests, combined with financing analysis, have reached the point where management decisions on whether or not to undertake OTEC projects are the critical factors. These decisions are difficult when an oil glut exists (probably a temporary one: crude oil prices have fallen 10%, but natural gas prices are up 23% from a year ago, Ref. 1). The long-term financial markets that allowed capital-intensive industries to finance at low fixed rates have all but disappeared (Ref. 2), and many companies have limited financial flexibility for new commitments. This lack of new commitments, on the other hand, leads to increased interest and thus flexibility on the part of insurance companies to find new projects to underwrite. A further factor in the quarter was the passage in August of the Tax Equity and Fiscal Responsibility Act of 1982, which lessened the attractiveness of OTEC as a tax syndication. This could be offset by new legislation that has been introduced but has not received Congressional action, such as the Renewable Energy Incentive Act of 1982, H.R. 7268.

During the quarter, extensive comments and information were exchanged between the author and C. N. Toftoy in the preparation of Ref. 3, which reports on the types of businesses that could have potential interest in operating and/or exporting OTEC plants, including the necessary involvement of the chief executive officer (CEO) because of an OTEC project's size. In addition, an informal input by a company president who has some background in OTEC listed the following points that could be considered in a CEO's decision:

1. Technical risk – Whether to be the first to build a new concept.
2. Financial risk – Management always adds further conservatism and expects costs to be much higher than advocates claim.
3. Political risk – Too many examples have been seen of government-sponsored programs that have been hamstrung or redirected (e.g., synthetic fuels projects).
4. Other options – OTEC may be less attractive than other options for the money or the workforce.
5. Popular wisdom – OTEC does not have a universally good press.
6. General state of business – New ventures are very difficult to start with the current depressed economy and earnings.

Offsetting the negative considerations may be special considerations such as the availability for only a specific period of the 15% business energy investment credit provided by PL 96-223. This credit currently is to expire December 31, 1985. The tax syndication potential with these energy investment credits creates a special situation that may be of interest to management because of the tax advantages and large positive early years' cash flows. This special profit potential, with the same set of input assumptions under the 1981 and 1982 Tax Acts, is summarized in Table 1 for a company that could build the OTEC heat exchangers and provide basic materials such as aluminum, cement, and/or aggregate.

STATUS OF OTEC COMMERCIALIZATION PROJECTS

The status of OTEC commercialization projects as of September 30, 1982, according to information available to the author (Ref. 4), is shown in Table 2. The first four projects are Japanese; all are reportedly under construction or completed and in operational tests. The construction projects are reportedly being done with funding by the Japanese government. The two 40 MW scale U.S. projects for Hawaii are in the conceptual design phase with U.S. government cost sharing. The other U.S. projects are conceptual, without U.S.

Table 1

Profit potential.*

Construction Years	1982 Tax Act 1984-86 ($M)	1981 Tax Act 1983-85 ($M)
Up-front cash needed	20**	5
Net profit potential†:		
Total cash flow	95.2**	113.8
Construction profit	31.6	31.6
Management fee profit, const.	0.7	0.7
Management fee profit, oper.	4.5	4.5
HX fabrication profit	4.7	4.7
Materials profit	3.5	3.5
Engineering profit	0.8	0.8
Total profit	$141.0	$159.6

*Baseline case assumptions for large-scale demonstration OTEC vessel delivering average of 51.4 MW electric power ashore to Puerto Rico Electric Power Authority grid. Assumes tax law modification to allow use of investment tax credit and business energy investment credit.

**Data are for an OTEC vessel. If OTEC plant does not qualify as personal property because of on-land or nonmovable bottom-sitting character, up-front cash requirement would be at least $10 million additional, and total cash flow amount and total profit would be about $28 million less under the 1982 Tax Act.

†All figures discounted by 15% per year to 1983 value.

government support. The Swedish and French projects are also conceptual.

The ability to raise private financing has apparently received more in-depth analysis and review to date for the Puerto Rico 50 MW Maryland Ocean Thermal Energy Corporation project (51.4 MWe estimated average annual delivered power to shore) than for other projects not supported by the U.S. government. The APL design work on a 40 MWe nominal OTEC pilot plant of barge-type design with Alclad aluminum heat exchangers for siting off Puerto Rico (Ref. 5) has been used as the basis of the costs. The financial analysis results (reported in Ref. 6) assumed that existing tax laws could be modified to provide investment tax credits (ITC) and business energy investment credits (BEIC) for a first OTEC demonstration project off Puerto Rico. A similar analysis for the lower temperature differential that would be available at a Hawaiian site, using the same costs, was reported in Ref. 7. The resultant summary of typical OTEC vessel cash flow cases appears in Table 3 for demonstration and commercial-scale OTEC projects, using our baseline input assumptions, for Puerto Rico, Hawaii, methanol, and ammonia under the 1981 Tax Act (columns 4 through 6) and under the 1982 Tax Act (columns 7 through 9).

In both the Puerto Rico and Hawaii cases, calculations were made and charts prepared on the degree of sensitivity to "reasonably possible" cost overruns and negative movements of such factors as interest rates, inflation rates, and take-or-pay contract

Table 2

Status of OTEC demonstrations.

Site	Scale (MWe)	Construction Team	Status
Nauru	2.5–10*	Toshiba, Japan	100 kW* 1 yr test completed, 2.5 MW under construction
Hiroshima area	0.05*	Kyushu Electric Power, Japan	Completed, in test
Kumezima, Okinawa	3	Japan	Under construction
Agunishima, Okinawa	1	Japan	Under construction
Hawaii (Mini-OTEC)	0.05*	Lockheed, U.S.	Completed, out of use
Hawaii (OTEC-1)	1	Global Marine, U.S.	Completed, out of use
Hawaii	40	General Electric, U.S.	Conceptual design
Hawaii	40	Ocean Thermal Corp., U.S.	Conceptual design
Guam	10–40	International Energy Enterprises, U.S.	Concept; capital formation and license
Puerto Rico	50	Maryland Ocean Thermal Energy Corp., U.S.	Concept; capital formation – no contract
St. Croix	12.5	OTEC International, U.S.	Concept; contract – capital formation
Palmyra Atoll	50	Project Energy, U.S.	Concept, NH_3 and mariculture
Jamaica	10	Sweden	Concept
Tahiti	3.5	France	Concept
Martinique	?	France	Concept

*Gross power rating; all others are net power.

Table 3

Typical OTEC vessel cash flow cases.*

OTEC Product	1982 Product Price	OTEC Vessel Cost, 1982 dollars (M)	1981 Tax Law: Revenues, 1986-2010 ($B)	1981 Tax Law: Net Cash Flow, 1983-2010 ($B)	1981 Tax Law: FMRR†† (%/yr after taxes)	1982 Tax Law: Revenues, 1987-2011 ($B)	1982 Tax Law: Net Cash Flow, 1984-2011 ($B)	1982 Tax Law: FMRR†† (%/yr after taxes)
Delivered electric power Puerto Rico (51.4 MWe conservative case) – barge type	92 mills/kWh	326 ($6400/kW)	4.4	1.1**	32**	4.8	1.2	24**
Delivered electric power Puerto Rico (first 266 MWe) – barge type	92 mills/kWh	960 ($3600/kW)	23.2	9.6	24	35.7	14.7	28
Delivered electric power Hawaii (45.4 MWe conservative case) – on land or tower	92 mills/kWh	326 ($7200/kW)	3.9	0.8	30	4.2	0.8	22†
Delivered electric power Hawaii (first 235 MWe) – on land or tower	92 mills/kWh	960 ($4100/kW)	20.5	8.2	23	31.6	12.4	21†
Methanol (60 MWe conservative case) – barge type	$295/ton or $0.98/gal	348 ($2200/annual ton)	5.4	0.919	31	5.9	0.955	21
Methanol (325 MWe) – barge type	$295/ton or $0.98/gal	1001 ($960/annual ton)	32.5	12.2	25	50.0	18.8	24
Ammonia (325 MWe) – barge type	$260/ton***	980 ($2600/annual ton)	11.7	2.9	18	18.1	--	--

* All cases are based on same assumptions, i.e., federal incentives except where indicated.
** Assumes technical correction to PL 96-223 to include ITC and BEIC for OTEC electric power delivered to U.S. commonwealths, territories, or possessions.
*** Competitive when U.S. natural gas prices are decontrolled.
† Assumptions include 10 yr amortization of interest under construction, 5 yr depreciation.
†† 15% short- and long-term reinvestment rates.

prices to be paid for the electric power produced. All were found independently to have a relatively small effect: ≤20% on the profitability of OTEC projects. It was also determined that a general cost overrun of 25% of the worst "reasonably possible" cost overruns and negative movement of factors would produce an overall reduction of OTEC project profitability of about 20% (30.6% reduced to 25.9% after taxes on the project's net cash flow for the Hawaii "baseline" case). These cost sensitivity results were reported in Refs. 6 and 7. The same costs used in Refs. 6 and 7 and related technical data were also used as the basis for the material on the effects of the 1982 Tax Act and the descriptive information on potential insurance coverage, reported below.

EFFECT OF THE TAX EQUITY AND FISCAL RESPONSIBILITY ACT OF 1982

Projected federal budget deficits of $155 billion for fiscal year 1983 and large forecast deficits for later years led, in August 1982, to passage by the Congress of the Tax Equity and Fiscal Responsibility Act of 1982. This was signed as Public Law 97-248 by President Reagan on September 3, 1982. This estimated tax increase of $98 billion divided U.S. OTEC projects into two categories:

1. Those commenced before July 1982 and completed before January 1986, for which the 1981 tax act would apply;
2. Those commenced after July 1982 or completed after January 1986, for which the 1982 act would apply.

The new provisions would adversely affect an OTEC project completed in 1986 or later in at least three ways:

1. The fast depreciation write-off of 175% declining balance for assets completed in 1985 and 200% for assets completed in 1986 were deleted. Depreciation will continue to allow 150% declining balance calculation as for 1981-84 completed projects.
2. The investment tax credit is reduced from 10 to 8%, or the basis of the asset for depreciation is reduced to 95% of cost.
3. For projects qualifying for BEIC, the depreciation basis is reduced by one-half of the BEIC, apparently by 7.5% for qualifying OTEC projects.

It is not clear whether a fourth negative impact of the 1982 tax act would apply to some OTEC projects. The question turns principally on whether the OTEC plant would be classified as "real" or "personal" property by the Internal Revenue Service. Informed opinions are that the OTEC vessel would be personal property if it is mobile, or could be picked up and moved without damage to the land etc. (Refs. 8 throught 11). For a floating OTEC vessel, including one moored and cabled to shore that could drop the mooring and cables, the personal property category appears to apply quite comfortably and to be in line with oil drilling rig decisions made previously and reviewed by the IRS. The net effect for the 1982 Tax Act, without the fourth negative impact, is to increase the "up-front" cash requirements for a 45 to 50 MW OTEC demonstration project by about $15 million and reduce the after tax financial management rates of return (FMRR with 15% short-term and 15% long-term reinvestment rate assumptions) by about six points. Results are shown in the last three columns of Table 3 for the Puerto Rico, methanol, and ammonia cases. The Puerto Rico case data are also shown in Table 1 for the 51.4 MWe demonstration-scale OTEC vessel.

For a land-based OTEC plant or a bottom-sitting offshore OTEC tower, the tax act may have the following fourth adverse effect:

4. Interest during construction may no longer be charged as an expense for nonresidential construction projects (except for the Alaska Natural Gas Transmission System and its related facilities) but must be amortized over 10 yr (Ref. 12).

The last three columns of Table 3 show the result of the fourth effect for the baseline assumptions for the Hawaii OTEC cases, on the assumption that this fourth provision would apply to the designs now under preparation. For a 45 MW OTEC demonstration project off Hawaii, the net effect relative to the 1981 Tax Act would be to increase the up-front capital requirements by about $25 million and to reduce the after tax FMRR by about one-quarter. The author has continued to use 5 yr depreciation for the Hawaii cases. If the IRS does not agree that land-based or bottom-based OTEC plants can be depreciated as vessels, then a 15 or possibly 10 yr depreciation would apply. This would further reduce the FMRR.

An important item to be understood in reading the above material is that all the Puerto Rico cases are calculated with the assumption that existing tax laws would be modified to allow a continental U.S. builder/operator tax syndication to benefit from ITC and BEIC on an OTEC demonstration project. While it is not completely clear, it is the opinion of the author that the tax code and PL 96-223, the Windfall Profits Tax Act, do not currently allow the use of the BEIC for an OTEC vessel unless the electricity generated or the product produced on board is delivered to one of the 50 U.S. states or the District of Columbia. Without modification of the tax laws, the first OTEC demonstration project for a U.S. commonwealth, territory, or possession does not appear feasible for all-private financing because it requires subsidization. Without a subsidy, the approximately $6400/kW (1982 dollars) OTEC demonstration project, at 50 MW and a first-of-a-kind engineering task, is too expensive. Application of the ITC and BEIC would be an off-budget subsidy that would allow the technology to be demonstrated at a Caribbean site. Subsidies in energy (e.g., over $146 billion for oil, $14.3 billion for coal, and $14.6 billion for nuclear to 1979 (1980 dollars), Ref. 13) have been a fact in U.S. policy. Our OTEC baseline demonstration vessel cash flow analysis for Puerto Rico also does not include Puerto Rico taxes, which Puerto Rican officials have stated will not be waived for the first OTEC demonstration vessel. These would run approximately 5% of profits (Ref. 14). The Ocean Thermal Energy Conversion Act of 1980, PL 96-320, does state that Title XI government loan guarantees of up to 87½% (which is the assumption used) would apply for OTEC vessels for the United States and its commonwealths, territories, and possessions. The author is unaware of any financial analysis done for Puerto Rico without the ITC and BEIC that would make private financing even remotely feasible.

INSURANCE INDUSTRY UNDERWRITING OF OTEC RISKS

In early 1982, it became apparent that industry executives perceived the first OTEC project(s) as high risk ventures, usually in areas where their company has no specific expertise or background. For example, a heat exchanger manufacturer might believe the risks were manageable with the OTEC heat exchanger but have concerns that high risks would have to be taken with the cold water pipe, the electric cable to shore, the mooring, or the overall project management. Other potential team members might perceive the OTEC heat exchanger as high risk. As a method for reducing risks, the insurance industry was asked if it would be willing to provide insurance coverage for the design risk and for the risk of tax credits recapture during the first five years of OTEC operation.

The insurance industry has responded favorably. In June 1982, discussions of an OTEC project with top decision-makers at four of the most innovative U.S. insurers led to the availability of coverage for the two major OTEC insurance needs: (1) a contract or contracts to cover the property and liability exposures arising out of the construction and continuing operations of the OTEC plant, and (2) an endorsement to the contract(s) providing recapture indemnity due not only to a casualty but also to design failure/error (Ref. 15). In October 1982, a more detailed prototype package of insurance for the construction and operational exposures for placement through Lloyds of London became available (Ref. 16) as discussed below.

Marine Construction Package. This package covers a period of 24 months commencing at a date to be given to the leading underwriter. It covers construction and/or erection and/or reconstruction and/or re-erection at the contractor's yard or elsewhere in the United States. It includes ship risks, stockpiling risks, and/or risks on materials including transit, launching, installation, outfitting, tests, trials, etc., and all work undertaken by the contractor and subcontractors until the OTEC project is finally delivered to and accepted by purchasers or until it sails from the United States. It includes the delivery voyage in tow or otherwise to an operating site and all installation and work at the site. Coverage is for the full cost of the project and up to 25% in ITC and BEIC. Institute War Clauses-Builders' Risks are included. Excluded are financial default or insolvency of any of the assured or their subcontractors, abandonment of the project or delay in completion because of altered ecomonics of the market, exchange rate fluctuations, failure of the assured to make proper applications to relevant authorities, etc. Daily payments are provided for delay in delivery. Coverage includes legal and contractual liabilities and excludes penalties, insolvency or financial default, vehicle or airplane use, and performance guarantees.

Marine Operating Hull Package. This coverage extends for 36 months after commencement of commercial operation and is subject to an annual review and recommitment by the principal Lloyds' underwriter and leading company. Coverage is for 100% of the OTEC vessel cost, 90% of the total amount of ITC and/or BEIC, 100% of any loss of revenue, and 100% of the liabilities limit. Table 4 summarizes the amounts at risk by year for private equity and ITC of 22½% of vessel cost, assuming a $400 million vessel and 1983-85 construction. Coverage includes loss or damage to the hull, components, and equipment and the breakdown of machinery to the extent the breakdown has not resulted from wear and tear or want of due diligence by the assured. Indemnity is for a daily amount for each 24 h or a pro rata share of 24 h. Liability coverage is also available for the period of operations with the exclusions set forth above.

No premium amount has been set forth for the insurance coverage pending detailed clarification of the final expected costs and a detailed schedule for construction and start of operations. For qualified OTEC projects, the provision of this needed detail would be sufficient for a "Broker's Quotation," which would reflect a best estimate of the insurance cost. A list of questions to be answered prior to such a Broker's Quotation is available.

CONCLUSIONS

Work done during the quarter has resulted in a further definition of the major factors affecting a top management decision whether or not to go forward with a first large-scale OTEC demonstration project. The perceived risks have been evaluated by the insurance industry in the United States and in London. The conclusion is that OTEC vessel risks can now be quantified and that insurance can be made available to cover the risk of producing a viable OTEC vessel design, its construction, and the early years of performance insofar as they involve a risk of tax credit recapture. For an OTEC project of 40 to 60 MWe scale to be sited offshore a U.S. commonwealth, territory, or possession, modification of U.S. tax laws will be needed for private financing to be feasible, at least insofar as any financing analysis has been made known to the author. For a Hawaii or continental U.S.-based OTEC project, the ITC and BEIC do provide a subsidy for a first OTEC large-scale demonstration project, currently until December 31, 1985. Several bills have been introduced in Congress to amplify and extend this OTEC subsidy.

Assuming that a large-scale OTEC demonstration project can be designed, funded, constructed, and operated, the U.S. insurance industry and the Lloyds of London marine insurance industry have agreed that coverage to underwrite OTEC design risks and early years of performance against subsidy (tax credit) recapture is available. This insurance includes a full range of coverages, from hull risk to liabilities. Broker quotations have not yet surfaced but are available to qualified projects that can respond to a list of costing and scheduling questions.

Table 4

Summary of total equity capital contributions needed for a total OTEC base case project and amounts at risk for each year. (millions of dollars for year shown)

		At risk of			
		Noncompletion, Cumulative		Tax Credits Recapture, Cumulative	
Year	Equity Needed	%	Cost	%	Cost
1982	3.0	100	3.0	--	--
1983	4.45	100	7.45	100	8.2
1984	19.4	100	26.9	100	43.4
1985	26.4	100	53.5	100	91.35
1986	--	--	--	100	91.35
1987	--	--	--	80	73.1
1988	--	--	--	60	54.8
1989	--	--	--	40	36.5
1990	--	--	--	20	18.3
1991	--	--	--	--	--

NOTE. Just prior to final printing, the Broker's Quotation of costs is 3% of plant investment for the construction period and 2.3%, 1.9%, and 1.7% per year for the first three years of operations.

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OCEAN THERMAL ENERGY CONVERSION §4
OTEC Hybrid Plants ZY3AEO
Support: DOE/DOET
J. A. Whelan (NWC), J. G. Brophy (JHU),
and F. C. Paddison and G. L. Dugger (APL)
April-September 1982

GEOTEC RESOURCE EXPLORATION AT ADAK, ALASKA, AND LUALUALEI, HAWAII

The leading candidate site for possible use of a geothermal-enhanced OTEC (GEOTEC) plant at a U.S. Naval Station is the Naval Air Station at Adak Island, Alaska. The preceding companion report compares the technical and economic potential for a GEOTEC plant at Adak with that of one at the Naval Magazine at Lualualei, Oahu, Hawaii. This report covers the resource assessment effort for the April-September 1982 period because some planning activity in April was not covered in the April-June *Quarterly Report*. Summarized in this report are the planning, consultation, and preparations for geothermal resource field work at Adak during the July 27 to August 8, 1982 period, the results of the Adak work to date, and additional data on the geothermal resource at Lualualei.

RESOURCE ASSESSMENT AT ADAK

As reported in Ref. 1, Adak was visited in August 1981 by B. Marsh and J. G. Brophy of The Johns Hopkins University, J. A. Whelan of the Naval Weapons Center (NWC), China Lake, Calif., and J. J. L. Moore of California Energy Corp. As a result of that visit and prior efforts (Ref. 1), plans were made to return to Adak in July 1982 to collect further data, with the specific needs of a GEOTEC plant in mind (Refs. 2 through 4). A meeting was convened on July 20, 1982 with B. Marsh, G. V. Keller from the Colorado School of Mines, D. B. Hoover of the U.S. Geological Survey, and S. Billington from the University of Colorado, all geophysical experts with considerable prior experience in resource assessment at Adak (Refs. 4 and 5). The resulting program plan was reviewed with representatives of NWC, APL, and DOE and was carried out, to the degree possible, from July 27 to August 8, 1982 at Adak. The various sampling and data-gathering efforts by a team from the Geothermal Utilization Division, Public Works Department, NWC, as reported by Prof. Whelan (consultant to NWC), are discussed below. Then the geologic reconnaissance conducted by J. G. Brophy (from the Earth and Planetary Sciences Dept. at The Johns Hopkins University) and R. Abbruzi, a colleague from Amherst College, is summarized. Overall, the results are encouraging, but analytical work on the samples gathered is not yet complete.

SAMPLING AND DATA-GATHERING EFFORTS AT ADAK

Soil Geochemical Survey. During the July 27 to August 8 period, 90 soil samples were collected for trace element analysis. Coverage included the Mt. Adagdak hot spring at the east shoreline of Andrew Bay, the Cape Kiguga warm spring, and complete coverage, at half-mile intervals, of the portion of the island from Finger Bay north, except highly restricted areas. Commencing with FY 83, mercury is the element of prime interest; however, an X-ray fluorescence screening will be made to ascertain whether other heavy elements of interest (usually arsenic and/or antimony) are present. If present, the samples will be assayed for those elements.

Water Sampling. Samples of water were collected from the hot spring at Mt. Adagdak, the warm spring at Cape Kiguga, seawater from Andrew Bay, and the cool spring at Cape Kiguga. The first two samples were collected to determine whether dumping geothermal fluids into the ocean would be harmful, the third for background information. The analyses for the three samples are presented in Table 1. At present, waters are being evaluated by the environmental section in NWC's Public Works Department. The cool-spring water from Cape Kiguga was analyzed for major components (Table 2). The criteria used were the assumptions that if the amount of an element present in the spring water is less than that in seawater or less than allowable in potable water as recommended by the U.S. Public Health Service (Refs. 6 and 7), the effluent could be dumped into the ocean. In comparing the major element analyses, as reported earlier in Table 1 of Ref. 1, the only discrepancy seems to be in the magnesium content of the Adagdak waters as determined by Miller and Smith (Ref. 8) and Moore (Ref. 9). At present, Prof. Whelan favors the values given by Miller and Smith (near 2%) because they ran duplicate samples.

The Adagdak spring water contains much less copper, lead, and zinc than the maximum allowable in potable water. Therefore, on the basis of these elements, there should be no objection to dumping these fluids into the ocean. However, the arsenic, fluoride, and cadmium contents are higher than those of seawater and those allowable in potable water. The mercury, chromium, antimony, nickel, and vanadium contents exceed those of seawater; the selenium, silver, molybdenum, and thallium contents are below detectable limits. No data are available on the allowable contents of these two groups of elements in potable water. Such data will have to be obtained. Since the Adagdak water is less concentrated (23,000 ppm of total dissolved solids (TDS)) than ocean water (25,000 ppm TDS), there should be no objection to Adagdak water on the grounds of concentration.

If the geothermal fluids are similar to those of the cool Kiguga spring (Table 2), there is probably no problem in dumping the water into the ocean; if the water is similar to that of the warm Kiguga spring (which is 300 yd south of the former), there might be an objection because of barium (less than 1 ppm) and thallium (less than 0.5 ppm). Some elements that were below the

Table 1

Water analysis, Adak, Alaska, July 30-31, 1982

Constituent	Hot Spring, Adagdak (ppm)	Warm Spring, Cape Kiguga, (ppm)	Seawater, Andrew Bay (ppm)
Fluoride	0.28	0.04	0.17
Arsenic	0.25	<0.01	<0.01
Copper	0.06	<0.01	0.01
Zinc	0.10	0.02	0.03
Barium	<1.0	<1.0	<1.0
Cadmium	0.04	<0.01	<0.01
Chromium	0.10	0.01	0.01
Lead	<0.01	<0.01	<0.01
Mercury	0.0006	<0.0002	<0.0002
Selenium	<0.01	<0.01	<0.01
Silver	<0.01	<0.01	<0.01
Antimony	3.4	<1.0	<1.0
Molybdenum	<0.1	<0.1	<0.1
Nickel	0.25	<0.05	0.05
Thallium	<0.5	<0.5	<0.5
Vanadium	0.2	<0.1	<0.1
Electrical conductivity μS/cm (K × 10^6 at 25°C)	10,362	360	10,000
pH	5.9	5.5	7.5

Table 2

Water analysis of cool spring water, Cape Kiguga, Adak, Alaska, July 31, 1982.

Constituent	Component (ppm)
Calcium	13.0
Magnesium	7.0
Sodium	72.0
Potassium	5.1
Carbonate	0
Bicarbonate	85.8
Cloride	93.5
Sulfate	21.0
Nitrate	4.0
Fluoride	0.08
Iron	<0.05
Manganese	<0.01
Arsenic	<0.01
Copper	<0.01
Zinc	0.01
Mercury	<0.0002
Silica	36.0
Aluminum	<0.2
Boron	0.06
Phosphate	<0.2
Bromine	<0.2
Lithium	<0.01
Nitrite	<0.002
Ammonium	insufficient sample
Hydroxide	none
pH	7.0

analytical detection limits in the latter spring and seawater may have to be checked by more sensitive methods.

It should be noted that Moore (Ref. 9) commented on unusual accumulations of dead marine life at both spring sites.

Magnetics and Gravity. Two hundred and ninety controlled magnetic stations were occupied. Reduction of data is about one-third complete. Because of the large amount of buried scrap iron from World War II, some of the magnetic data may not be interpretable. The gravity data are confirming and will define the low reported by Hoover (Ref. 10).

Microseismic Survey. The Navy funded a 30-day microseismic survey, which is being conducted by the Earth Science Laboratory, University of Utah Research Institute. The survey should be completed in October 1982, and the interpretation should be completed in December. Unofficially, ESL has reported considerable microseismic data.

Hydrothermal Alteration Investigations. Seven rock samples, four from the Adagdak hot spring area (least altered, altered, most altered, and breccia zone) and three from the Kiguga warm spring area (silicified rock, iron-stained breccia, and pyrite-containing breccia), were collected. Thin sections are being prepared for petrographic examination during the next quarter. If petrographic examination indicates significant alteration, further mineralogic studies using X-ray fluorescence, X-ray diffraction and fluorescence, differential thermal analysis, and scanning electron microscopy, will be made. Alteration studies may give additional data on the temperature of the reservoir and the composition of geothermal fluids.

GEOLOGIC RECONNAISSANCE AT ADAK

The objectives of the geologic reconnaissance by Brophy were to:

1. Study the major fault and fracture systems in the Mt. Adagdak-Andrew Bay area through the use of aerial photographs and field checking, with emphasis on the location of the major northeast trending fault proposed by Butler and Keller (Ref. 11).
2. Map in detail the known hot spring on the west side of Mt. Adagdak and correlate, if possible, its location with the major fault and fracture system(s) in the region.
3. Verify and sample the hot spring reported by Moore (Ref. 9) at Cape Kiguga on the west side of Mt. Moffett.

A stretch of exceptionally good weather (by Aleutian standards) allowed all three objectives to be met.

Major Fault and Fracture Systems. The geology of northern Adak Island is described in detail by Coats (Ref. 12). A brief summary is provided here, including aspects seen this summer. Northern Adak Island is dominated by the two late Cenozoic to Quaternary age volcanic centers of Mt. Moffett and Mt. Adagdak, between which lies Andrew Bay. On the east side of Andrew Bay are the remains of a third volcanic center, the Andrew Bay Volcano, which previously stood at the spot now occupied by the bay (Fig. 1). The older center, Mt. Moffett, which has an approximate elevation of 3600 ft, has undergone alpine glaciation during some period in its history. The result is a rugged, rocky terrain with numerous perennial snowfields and very little vegetation cover. Mt. Adagdak, reaching an elevation of only 2200 ft, has not undergone any glaciation, perhaps because of its low elevation and/or younger age. Consequently the topographic relief is much more subdued, and there is complete vegetation cover. The only exposed rock outcrops in the Mt. Adagdak region are at the summit and along its base where wave action has exposed the bedrock.

All of Adak Island is underlain by the slightly metamorphosed early Tertiary age rocks of the Finger Bay volcanics. From Fig. 1, it appears that the Finger Bay volcanics extend beneath Mt. Moffett and Mt. Adagdak. Clasts of Finger Bay rocks found this summer within some flows on Mt. Adagdak support this view.

Northern Adak Island consists of the remnants of the once large Andrew Bay Volcano (Mt. Moffett and Mt. Adagdak). All three volcanic complexes are dominated by andesitic lavas and mud-flow deposits (lahars) with minor amounts of basaltic extrusive rocks. Numerous gabbroic beach cobbles along the bases of both mountains indicate the presence of such intrusions within the two volcanic complexes, although field work this season did not find any such surface exposures.

The older Finger Bay volcanics are highly fractured and faulted. The main fracture system, which extends regionally through many islands of the Andreanof Group, has an average trend of N65°E. On Adak Island, this system is best shown by the Finger Bay Fault (Ref.12). A fault with the same trend was proposed by Marsh (discussed in Ref. 1) after he heard of the cracking of the airfield runways. Although Marsh saw no surface expression on the runways in 1981, the aerial photos do indicate to Marsh and Brophy a N80°W fault line through Mt. Moffett that intersects the runways. Smaller scale fracture systems trend from N60°E to N60°W (Ref. 12). The younger rocks in the northern part of Adak Island are devoid of any obvious major structural system(s). The tundra cover on Mt. Adagdak obscures older faults. The major northeast fault proposed by Butler and Keller is not visible. The only recognizable faulting of recent times has occurred along the northeastern slope of Mt. Adagdak, which has been cut by a number of faults trending N80°W (Fig. 2). According to Coats (Ref. 12) and supported by field checking this past season, these faults may have upwards of 8 ft of measurable displacement.

Summary of Field Work near the Adagdak Hot Spring. The Adagdak hot spring, located along the eastern side of Andrew Bay (Fig. 1), is found within a wave-cut terrace along the base of a sea cliff cut into the Andrew Bay volcanics. The hot spring presently has a low discharge volume, but at some time during its past history the discharge may have been much higher. It is located within a block of andesitic rock bounded on the north and south by N80°E faults and exists as several small discharges (Fig. 3). The remains of the Andrew Bay volcanics consist of a complexly interfingering series of andesitic lavas, volcanic mud flows, and thinly

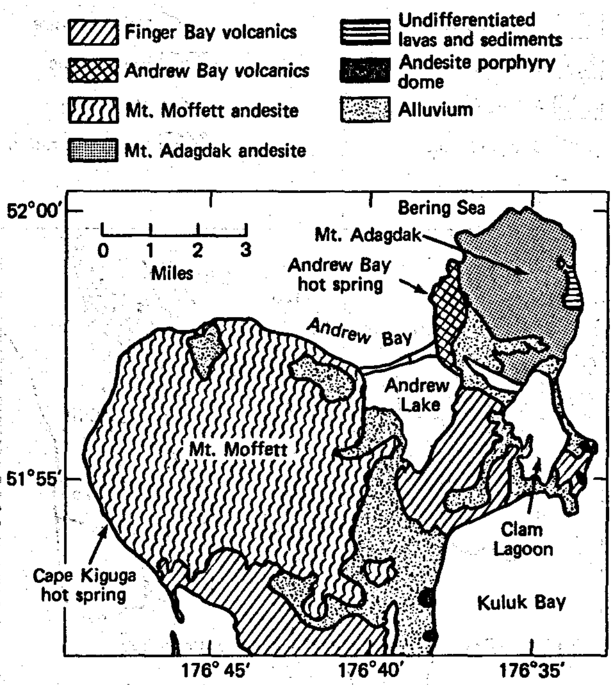

Fig. 1 Schematic geologic map of northern Adak Island showing the location of the two known hot springs. The geology is taken from Ref. 12. (82-3/98)

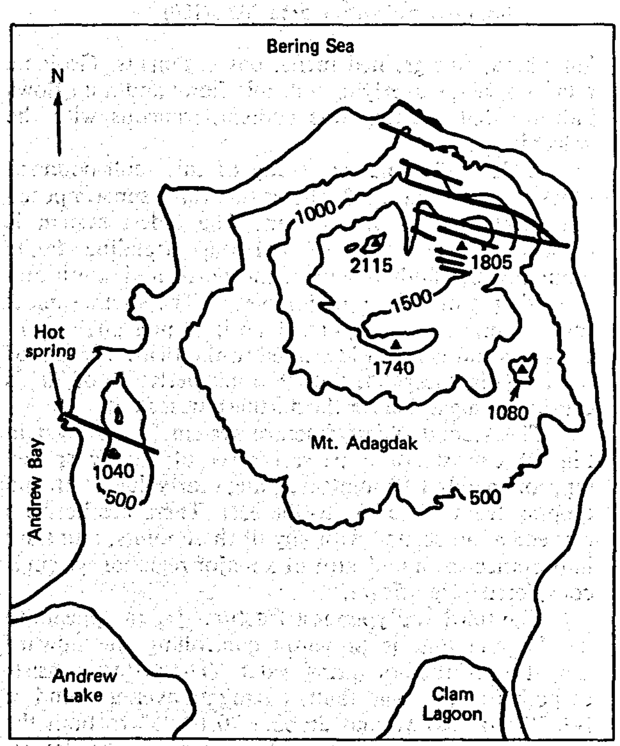

Fig. 2 Topographic map of Mt. Adagdak and the Andrew Bay area. The locations of recent fault activity are shown in heavy black lines. (82-3/99)

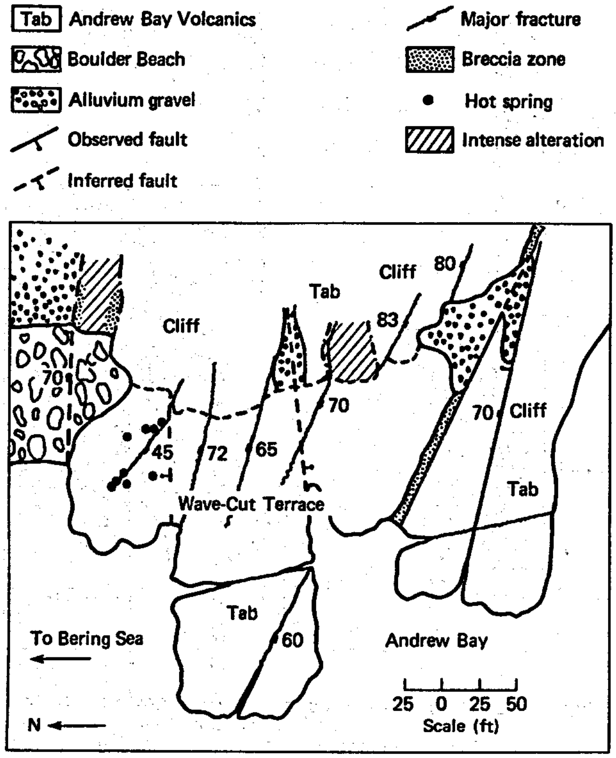

Fig. 3 Detailed geologic structural map of the Mt. Adagdak hot spring area. (82-3/100)

laminated, fine-grained tuffaceous sediments. Geologic relations of the overlying volcanic flows and mud flows indicate that faulting was contemporaneous with the volcanic activity.

A detailed structural study of this fault-bounded block of andesite (Fig. 3) shows that three superimposed structural systems are present. The oldest system is present as the series of northeast trending faults bounding the fault block on the north and south and dissecting it into three major pieces. The southernmost fault is not shown in Fig. 3 as it is presumably underwater and was not identified in the field. The dip of the faults is uncertain, though a northerly dip of 70° is cautiously suggested for the northernmost fault.

The second oldest fracture system (not shown in Fig. 3) consists of a pervasive set of closely spaced (approximately 1 ft) joints trending nearly due north and dipping from 70 to 75° to the east. There has been no movement associated with any of these joints, and their importance as an indicator of a major regional system is considered insignificant.

The third and youngest fracture system appears to be the one that is presently controlling the upward migration of the hot spring waters. The system consists of both fractures and faults having an average trend of N70°W to N80°W and dipping 70 to 75° to both the northeast and the southwest. However, the largest percentage of fractures and both of the major faults associated with this system dip to the northeast. At least one of the faults may have been active recently for it can be traced on the aerial photographs for some distance to the southwest, and it offsets volcanic rocks lying stratigraphically above the fault-bounded block of andesite hosting the hot spring.

All of the rock in the vicinity of the hot spring has been slightly altered to a greenish color; the rock close to the hot spring has been more intensely altered and silicified. Two regions of very intense alteration are noted in Fig. 3 where silicification, brecciation, and reddish iron-staining have been most extreme. Neither of these areas is associated with the current area of hot spring activity, but their presence suggests that the hot spring was more active during its earlier history. Rock samples representing all degrees of alteration and silicification were collected for further study by NWC (see Hydrothermal Alteration Investigations).

Verification of the Cape Kiguga Warm Spring. This spring is located in the first major rock obstruction encountered as one travels north on the beach along the western side of Mt. Moffett (Fig. 1). The northeast-southwest trending cliff where it is located is a highly brecciated, altered, and silicified andesite. To the south of the cliff is a wave-cut terrace measuring approximately 200 by 100 ft. The rocks are not brecciated but are highly fractured and intensely silicified. The two major fracture sets trend N40°W and N80°W. The presence of the cliff is attributed to a northeast-southwest trending fault along which the hot spring waters have migrated upwards. Aerial photography of the region to the east of the hot spring does not show any evidence of recent movement along the fault.

The waters seeping out of the base of the cliff are cold to the touch, but the beach cobbles over which the water flows are stained to a dark reddish-brown. A strong sulfurous smell is present. Approximately 300 yd to the south of the intensely altered and silicified cliff, a seepage of lukewarm water comes from the tundra at the upper edge of the beach. The beach cobbles are again stained a dark reddish-brown and a slight sulfurous oder is present. The degree and extent of alteration and silicification suggest that at one time this may have been a major hot spring system, larger than the Andrew Bay hot spring. Rock and soil samples from the vicinity of the altered area and water samples from the cold spring at the base of the cliff and the warm spring to the south were collected.

THE RESOURCE AT LUALUALEI, OAHU,HAWAII

Lualualei is a valley on the east side of the Island of Oahu. Oahu is the third largest of the Hawaiian Islands and has the largest population. The Naval Magazine in the valley saw intense activity during World War II, the Korean War, and the Vietnam War; it is now in caretaker status.

Lualualei is a sedimentary valley with deposits varying in depth to 1200 ft at the Naval Base. These deposits overlie basaltic volcanic rocks from the Waianae Volcano, a part of whose caldera is considered to be located in the Lualualei Valley (Ref. 13), or the younger Koolau Volcano that formed the eastern half of the island. The basaltic rocks are very permeable and are the source of potable water. The permeability decreases with increasing depth. The plug of the Koolau Volcano probably has cooled to the point where the gradient is near normal (Refs. 14 and 15). Reference 13 cites the following water well temperatures at three points around the valley: 26°C at 550 ft, 24°C at 500 ft, and 27°C at 200 ft. References 15 through 17 report a bottom hole temperature recording of 31°C at 1500 ft.

Cox et al. (Ref. 13) document geophysical and geochemical studies of the Lualualei Valley. The result of this study is at variance with earlier studies, concluding that the Lualualei Valley may lie over the caldera of the Waianae Volcano, and Cox et al. recommend further investigation in the northern inland region of the Naval Base where the depth to the possible heat source (i.e., the old caldera) is at a minimum. It should be noted that some geophysical and geochemical studies are sensitive to prior land use (e.g., mercury may have come from mercury fulminate in munitions, Ref. 15) and residential construction of the type that occurred at the Lualualei Naval Base during the war years.

In summary, a geothermal resource may exist at depth under the Lualualei Valley. Whether it is practical for GEOTEC depends on the temperature and permeability as a function of depth. Data are available from the Island of Hawaii that can provide a first-cut estimate of the probable results of the additional drilling that was recommended in Ref. 13. The present consensus is that a geofluid temperature of 135°C may be attainable at Lualualei; this value was used for a cost estimate in the companion report.

CONCLUDING REMARKS AND FUTURE PLANS

The reconnaissance work by Brophy at Adak did not find surface evidence of the N60 to 70°E fault reported in Ref. 11. Some recent faults on the northeast slope of Mt. Adagdak and near the hot spring at the Andrew Bay shoreline have an approximate N80°W trend. The aerial photographs also indicate a N80°W fault on the southern slope of Mt. Moffett that would intersect the runways. There is no apparent structural connection between the Adagdak and Cape Kiguga springs.

Additional dipole-dipole or dipole-bipole electrical resistivity surveys could be made prior to drilling. These surveys could delineate conductive zones—alteration, brines, or high temperature zones—at shallow to moderate depths.

The two drill holes on Adagdak should be temperature logged again. Brophy noted that the siting of the two holes on Adagdak, particularly the second hole, were stipulated where he would have sited them on the basis of his fracture studies. An aerial infrared survey of the waters around Mt. Adagdak had been recommended (Ref. 5); however, time, concern about suitable weather, and limited funds did not allow its consideration.

When the current studies are complete, these data, together with the microseismic studies of Butler and Keller; the gravity and magnetic, audio-magnetotelluric, telluric, electromagnetic, and self-potential surveys of Hoover; and the excellent geologic-geochemical study by Miller and Smith, will allow as complete synthesis and modeling as is possible without drilling. The data should allow siting of two 3000 to 6000 ft holes, as recommended by NWC as the next stage of exploration.

No further resource work at Lualualei is presently planned, but further consideration will be given to the Island of Hawaii as a possible civil application of GEOTEC.

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OCEAN THERMAL ENERGY CONVERSION §5
OTEC Hybrid Plants ZY3AEO
Support: DOT/DOET
G. L. Dugger, L. L. Perini, and D. Richards
July-September 1982

PRELIMINARY GEOTEC PLANT COST ESTIMATES

For near-ocean sites where a geothermal water resource with a temperature in the 120 to 200°C range is available, a combination (GEOTEC) of geothermal and ocean thermal energy conversion (OTEC) technology including seawater cooling may be attractive as a renewable-energy resource. Prior *Quarterly Reports* have addressed the resources and power cycles being considered; this report presents some preliminary cost estimates for two of the candidate Navy Station sites, Adak Island, Alaska, and Lualualei, Oahu, Hawaii, and a companion report describes some recent exploration at Adak Island. GEOTEC plant costs for Adak could prove attractive enough to stimulate a private venture to build a plant and sell power to the Navy. Because of the limited data base for component and well-field costs, the costs are, at best, rough approximations and should be viewed more as a basis for figure-of-merit sensitivity investigations than as absolute values at present.

SUMMARY

Preliminary cost estimates for single-closed-cycle (binary) plants at Adak are given in Figs. 1 and 2. Figure 1 shows estimated cost versus reinjection temperature (T_{inj}) for four working fluids, with an assumed geofluid temperature (T_{GF}) of 180°C. Within the accuracy of the assumptions, the costs for plants using isobutane, propane, and R22 (chlorodifluoromethane) are the same, approximately \$63M for 10 MWe net power, or \$6300/kWe with $T_{inj} \simeq 80$°C. For water or ammonia as the working fluid, the estimated cost is \$57M or \$5700/kWe. Since water would be much easier to handle than ammonia, it would probably be the preferred working fluid. Figure 2 shows the effect of geofluid temperature for the plant using water; if T_{GF} proved to be only 120 to 125°C at Adak, the plant cost would double.

The plant cost would be substantially reduced by going to a dual-binary cycle using water in the higher temperature loop and ammonia in the lower one. Figure 3 shows that at 180°C (now believed to be the probable T_{GF} for Adak), the minimum cost would be \$43M or \$4300/kWe with T_{inj} = 70°C. Figure 4 shows the results of sensitivity analyses for this system with T_{GF} = 180°C. Nominal values are indicated by the circles. The nomenclature used is:

ΔT_E = inlet or maximum temperature difference in the water evaporator (the minimum temperature difference is 5.6°C or 10°F),

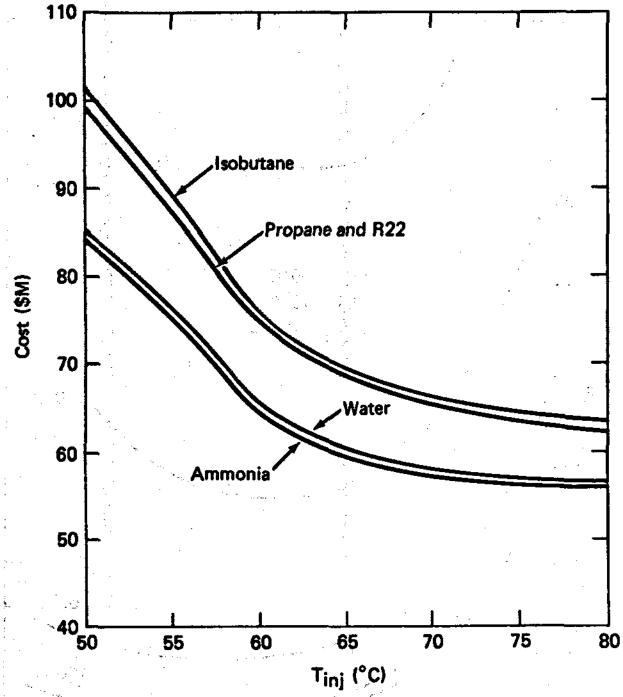

Fig. 1 Effects of working fluid and reinjection temperature on cost – single-binary cycle, 180°C geofluid, 5°C seawater, Adak site factors, 10 MWe net power, and 100 m drawdown. (82-3/82)

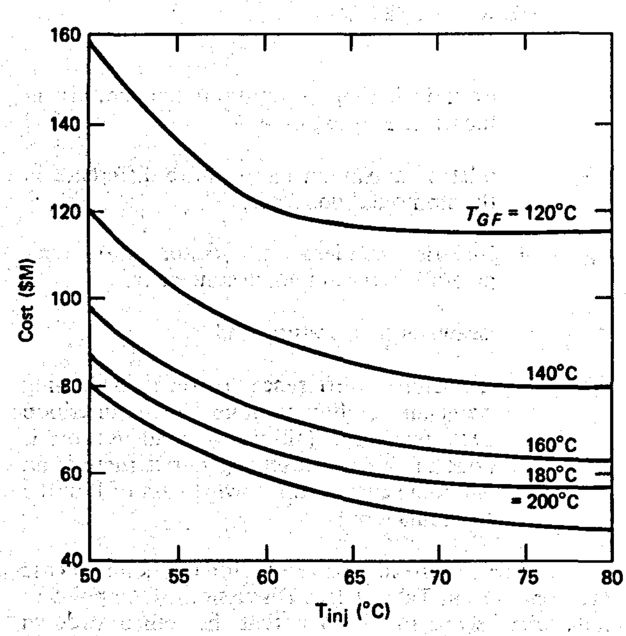

Fig. 2 Effects of geofluid temperature and reinjection temperature on power plant cost – binary cycle (water), Adak site factors, 5°C seawater, 10 MWe net power, and 100 m drawdown. (82-3/83)

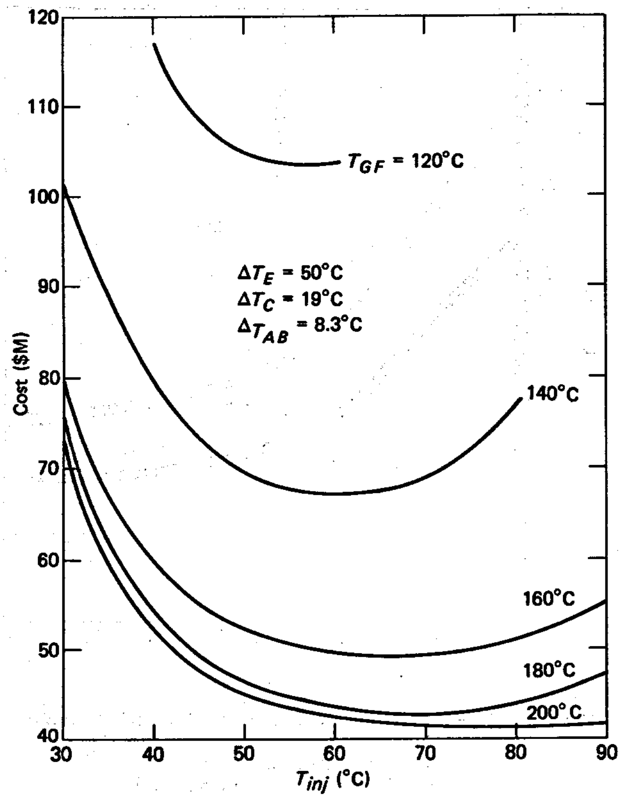

Fig. 3 Power plant cost estimates for Adak, AL, as functions of geofluid temperature and reinjection temperature – dual-binary cycle (water/ammonia), 10 MWe net power, T_{SW} = 5°C and 100 m drawdown. (82-3/84)

T_E = isobaric boiling (saturation) temperature in the water evaporator,

ΔT_C = inlet or maximum temperature difference in the ammonia condenser,

T_C = isobaric condensation (saturation) temperature in the ammonia condenser,

T_{SW} = seawater temperature, and

ΔT_{AB} = temperature difference between condensing water and boiling ammonia in the interloop heat exchanger (all water condensation is done in this heat exchanger, but there is an ammonia evaporator downstream of it in the ammonia loop).

The cost elements and results for the nominal case are presented in Table 1 (see Discussion). One point to note with regard to Fig. 4 is that the well drawdown probably will exceed the nominal 100 m value; if it goes to 250 m, the cost will rise approximately 15%, to $49M.

Figure 5 presents cost estimates for a single-cycle plant using ammonia at the Naval Magazine at Lualualei, Oahu. The assumed T_{GF} is 135°C. The annual average surface seawater temperature is 25°C; for lower temperatures the seawater intake pipe must be run

Table 1

Cost estimates and results for nominal case.*

Input parameters			
Water velocity in pipes (ft/s)		7.0	
Heat exchanger total area (ft^2)		46440.0	
Number of wells		3	
Number of injection wells		2	
Hot water pipe ID (ft)		1.066	
Cold water pipe ID (ft)		2.828	
Equipment costs		$K	
Heat exchangers ($25/$ft^2$)		1161	
Turbine-generator ($300/kW)		3355	
Salt water pumps		23	
Geofluid pumps ($150k/production well)		450	
Pump A working fluid		21	
Pump B working fluid		21	
A. Equipment cost subtotal			5031
Miscellaneous building costs			
Piping, valves, etc.	(0.100A)	503	
Electrical	(0.070A)	352	
Structural steel	(0.020A)	101	
Instrumentation	(0.025A)	126	
Insulation	(0.015A)	75	
Painting	(0.010A)	50	
Buildings	($5/$ft^2$ HX)	232	
B. Miscellaneous building costs subtotal			1439
C. Total building costs (A + B)			6470
Field installation	(0.35C)		2264
D. Total installed cost subtotal			8734
Engineering and management	(0.12D)		1048
Interest during construction	(0.18C)		1165
E. Total plant and equipment cost (U.S.)			10947
F. Total plant cost at site			21894
Wells and piping			
Production wells ($1000k/well)		3000	
Reinjection wells ($1000k/well)		2000	
Geofluid piping, valves, insulation		899	
Injection piping, valves		657	
Saltwater piping, valves, and intake		258	
G. Total for wells and piping costs (U.S.)			6814
H. Total for wells and piping cost at site (3 × line G for Adak)			20442
I. Total power plant cost, U.S. (E + G)			17761
J. Total power plant cost at site (F + H)			42336 = $42.3M

*Water/Ammonia, T_{GF} = 180°C, T_{SW} = 5°C, T_{inj} = 70°C.

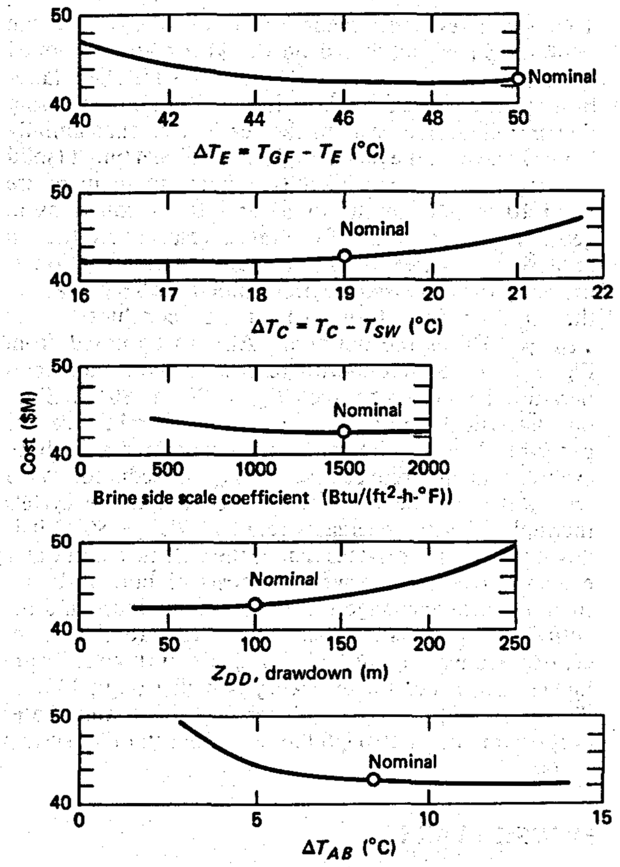

Fig. 4 Sensitivity studies – dual-binary cycle (water/ammonia), 180°C geofluid, 70°C injection temperature, 5°C seawater, and 10 MWe net power. (82-3/85)

2 to 4 km from shore. Based on the higher, more probable, cost of the seawater piping required to reach various depths and temperatures offshore (solid curves), the combination of T_{SW} = 10°C and T_{inj} = 80°C will be optimum, at a cost of $62M. However, this cost is based on continental United States labor and drilling costs, and it probably should be raised 30 to 50% for Hawaii. Thus, if the assumed T_{GF}'s for Adak and Hawaii (180 and 135°C) are realized, the cost of GEOTEC power at Lualualei will be roughly twice that for Adak.

DISCUSSION

The cost assumptions presently used for GEOTEC plants can best be illustrated by reference to Table 1, which shows the computer output for a sample case. The numbers in parentheses in the following discussion are values that can be modified by inputs to the program.

The equipment costs are calculated first. The heat exchanger cost is based on cost per unit of surface area ($25/ft²) and the total surface area of the heat exchangers (water evaporator, interloop heat exchanger, ammonia evaporator, and ammonia condenser in the water/ammonia dual-binary case). The turbine-generator cost is based on the cost per kilowatt of gross power ($300/kW) and the total gross power. The costs of seawater pumps and working fluid pumps for the two loops are related to a 1979 correlation based on data in Ref. 1:

$$\text{Cost} = 130.4X^{0.35} ,$$

where X is the product of head in psia and flow rate in gallons per minute. The pump costs are then doubled to allow for corrosion-resistant materials and three years of inflation. The cost per well for the geofluid downhole pump and booster pump is input as a fixed value, presently assumed to be $150,000. The total equipment cost (Table 1, line A) is then calculated.

The building costs are related to the total equipment costs by various factors, as shown in Table 1; e.g., instrumentation is 2.5% of the total equipment cost. The cost of the building to house the equipment is assumed to be proportional to the heat exchanger surface area ($5/ft² of heat exchanger total area). The building costs are then summed (Table 1, line B) and added to the equipment cost (line A) to arrive at the total material cost (line C). Installation cost is given by a fraction of the material costs (0.35) to arrive at the total installed cost (Table 1, line D). Engineering and management cost is a fraction (0.12) of the total installed cost, and interest during construction is a fraction (0.18) of the material cost (line C); both are summed with line D to arrive at the total plant and equipment cost in the continental United States (line E). A site cost factor (2 for Adak) can then be applied to line E to arrive at a plant and equipment cost at a site outside the continental United States. We assume that all major components will be assembled as far as possible on the U.S. west coast, skid-mounted, and delivered by barge to Adak.

Each production well is assumed to produce 1000 gpm (65 kg/s) of geofluid. On the basis of the geofluid flow required to operate the cycle, the necessary number of wells can be calculated. We assume one reinjection well for two production wells. The well costs are based on a dollar value per well for the continental United States ($1,000,000/well).

On the basis of an assumed flow velocity in the geofluid and piping system (7 ft/s), the required pipe diameter in the main trunk lines can be estimated. The piping costs including installation in both the geofluid and the seawater systems are based on a dollar value per inch of pipe diameter per foot of length ($12/in.-ft). We assume that for each production well 1000 ft of an 8-in.-diameter pipe and 1000 ft of main trunk line are required. For the geofluid pipe, 20% is added for insulation. For each reinjection well, we assume 1000 ft of 10-in.-diameter pipe and 1000 ft of main trunk line. For the seawater piping, a length (5280 ft) is assumed, and a factor (1.2) is applied to account for the intake system. The total well and piping cost in the continental United States is given by line G of Table 1. A site factor is then applied (3 for Adak) to give the cost at the other site (line H). The total power plant costs, including wells, are given on lines I and J for the continental United States and for a particular site (Adak), respectively.

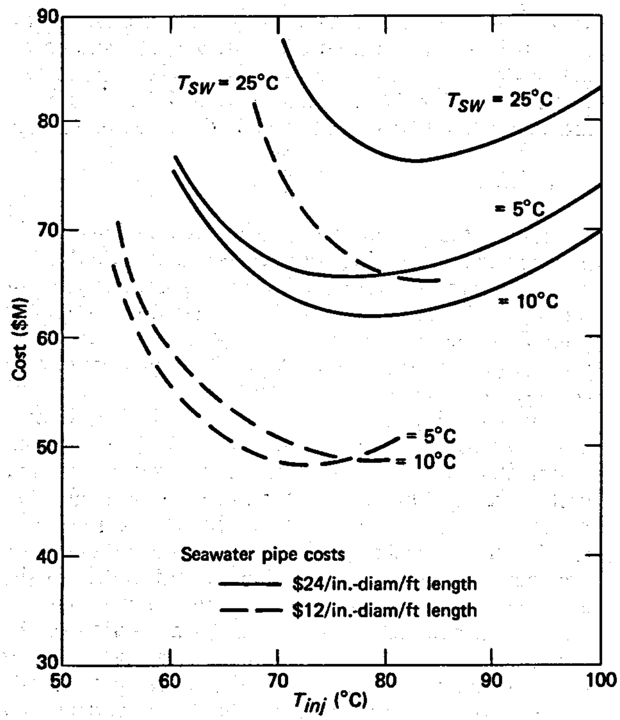

Fig. 5 Power plant cost estimates, Lualualei, Hawaii – single-binary cycle (ammonia), 135°C geofluid, and 10 MWe net power.

With regard to Lualualei, conversations of F.C. Paddison (APL) with James Whelan (Naval Weapons Center, China Lake, Calif.), Augustine Furumoto (Hawaiian Institute of Geophysics, Univ. of Hawaii), and George Keller (Colorado School of Mines) indicated that a maximum geofluid temperature of 135°C might be achievable at 1830 m depth.

We assume the plant would be located 1 km inland from the shoreline and that cooling seawater would be discharged into the sea 1 km from the shoreline. For the case when surface seawater is used, the total length of the seawater intake pipe would also be 2 km to allow adequate separation between the intake and discharge points. On the basis of bathymetry and temperature profile data taken near Kahe Point on the west side of Oahu Island (Ref. 2), we have estimated the depths and total pipe lengths (inlet pipe plus discharge pipe) needed to attain a desired seawater temperature. Three cases have been estimated: T_{SW} = 25°C (which represents an annual average surface temperature), T_{SW} = 10°C, and T_{SW} = 5°C. The results are:

T_{SW}(°C)	Depth (m)	Total Pipe Length (m)
25	0	4000
10	330	6800
5	750	9400

Two estimates were made of installed costs of the seawater pipes, one based on the $12/in.-ft mentioned previously, which is representative of installed land-based pipe costs (dashed lines in Fig. 5) and, recognizing that installed pipe costs in the sea will be substantially higher, one with the pipe cost doubled to $24/in.-ft (solid lines in Fig. 5). Decreasing the cooling water temperature from 10 to 5°C results in 15 and 16% reductions in geofluid and sea water flow rates, respectively (i.e., a reduction of three wells). However, this reduction is offset by the increased length of pipe necessary to attain the 5°C temperature, so it is concluded that T_{SW} = 10°C is the optimum. Also to be noted from Fig. 3 is the optimum with respect to reinjection temperature that occurs between T_{inj} = 70 and 80°C. Since our analytical approach is designed to minimize the geofluid flow requirement, the temperatures in both evaporators are reduced when T_{inj} is reduced. As a result, the turbine ΔT's are reduced, and the cycle's thermal efficiency decreases (e.g., at T_{inj} = 50°C it is down to 4.1%). This does reduce the well-field and water evaporator costs; however, the costs of both turbines, the three heat exchangers in the ammonia loop, and the entire seawater system increase, so that total cost increases. Conversely, at higher T_{inj}, the turbine ΔT's are higher, and hence the efficiency is higher (e.g., 13% at T_{inj} = 100°C), but the higher well-field and water evaporator costs outweigh the reductions in other system costs.

FUTURE PLANS

Further dual-binary cycle analyses will be done for Adak using other working fluid combinations and further refinements to the plant concept and computer program (e.g., addition of superheaters for cases where they may be beneficial). The cost input parameters shown in parentheses in the preceding section will be refined, if possible, and further cost sensitivity studies will be made.

At present, no further work is planned specifically for Lualualei because of the rather discouraging results presented here. However, on the island of Hawaii, there is a very promising geothermal resource. Although the Navy would probably have less interest in this island, the fact that undersea cables electrically connecting several of the islands are being considered portends civilian interest in the GEOTEC potential there. Hence, some estimates for the island appear warranted.

We plan to issue modest subcontracts to industry to confirm or refine these estimates and work out plant details early in 1983.

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OCEAN THERMAL ENERGY CONVERSION §6
Technology Base and Commercialization ZY3COE
Support: DOE/DOET
D. Richards and F. Welskopf
July-September 1982

SUPERVISION OF TESTING OF PNEUMATIC WAVE ENERGY CONVERSION SYSTEM

Although many technically feasible systems for converting ocean wave energy to usable power have been devised, economically attractive systems of general applicability have not been demonstrated. A novel pneumatic wave energy conversion (PWEC) device was conceived by M. McCormick of the U.S. Naval Academy (USNA) by which counter-rotating turbines are driven in unidirectional rotation by the oscillating airflow induced in a capture chamber by passing waves. The turbines are connected to an electrical generator by means of a combining gearbox. A prototype PWEC device was designed for at-sea testing on a barge together with other wave devices in an international experiment, but the PWEC device was not completed in time. It is now proposed that it be tested on a fixed, near-shore ocean platform.

The Naval Civil Engineering Laboratory (NCEL) has been requested to prepare for and conduct the test under APL's technical direction. In preparation for this at-sea test, precursor tests to determine the performance characteristics of the air turbine and the combined hydrodynamics and thermodynamics of the capture chamber have been defined. APL is developing a numerical model of the PWEC system. This model and the results of the test programs will be used to design the extended at-sea test.

SUMMARY

A review by NCEL of possible sites for an at-sea test of the PWEC device identified three candidate sites in California: Pt. Mugu, Mission Bay, and one of the Santa Barbara Channel Islands. Although the choice has not yet been made, the offshore tower at Pt. Mugu looks best, on the basis of cost and convenience. Figure 1 shows the probable configuration of the test assembly as it would be installed at Pt. Mugu. Before the device can be tested at sea, however, it will require several modifications and changes including a larger and stiffer base, a flywheel, test and control instrumentation, and systems to control the generator load and unit speed as well as emergency shutdown and safety procedures (Ref. 1).

The modifications will be performed as part of a larger task that includes a performance test of the air turbine. The test has been designed; the primary test goal is to produce a map of the turbine's characteristics similar to the one shown in Fig. 2. The map will be used to design the operating and load-control systems as well

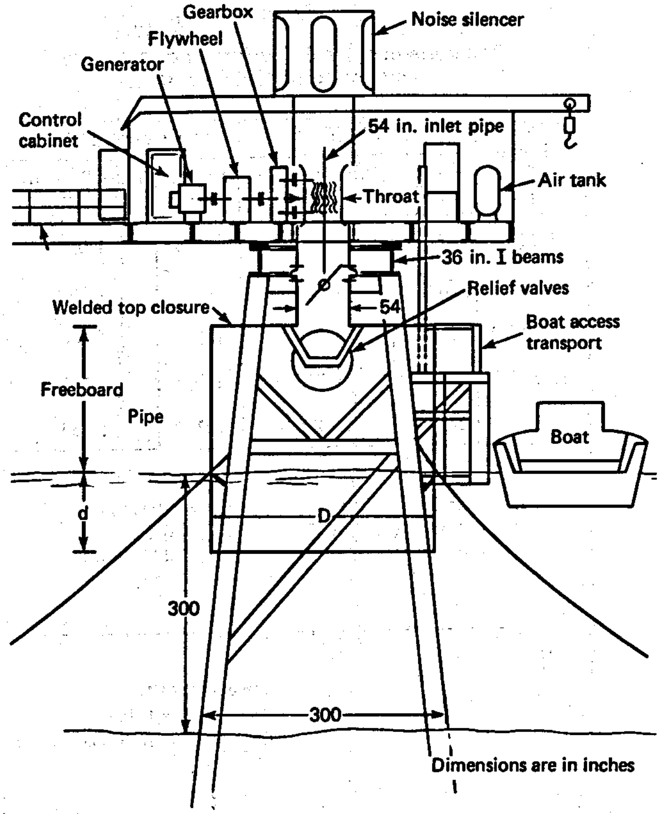

Fig. 1 Concept of PWEC test assembly at Pt. Mugu (Dixon's Tower). (82-3/87)

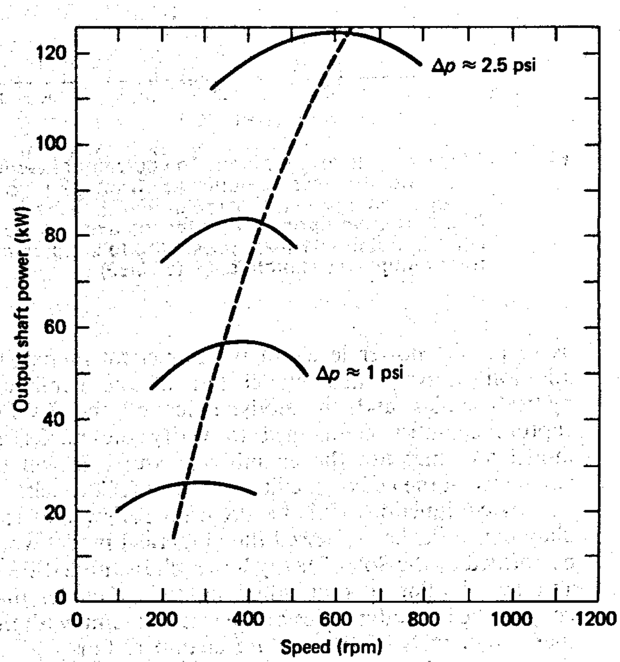

Fig. 2 Expected form of turbine operating characteristics map. (82-3/88)

Table 1

Comparison of PWEC performance estimates by two numerical models.

Wave Height, feet (m)	SERI Model		APL Coupled Model	
	Power (kW)	Peak Pressure Ratio	Power (kW)	Peak Pressure Ratio
3.3 (1.0)	66.5	1.083	36.4	1.056
6 (1.8)	211	1.187	89.3	1.109
10 (3.0)	567	1.379	189	1.200
15.7 (4.8)	1320	1.728	389	1.382
22.3 (6.8)	2612	2.336	703	1.653

Capture chamber parameters:

D = 25.2 ft (7.7 m) ℓ_0 = 20 ft (6 m)
A_t = 2.50 ft^2 (0.23 m^2) C_D = 0.6
η_t = 0.5 d = 20 ft (6 m)

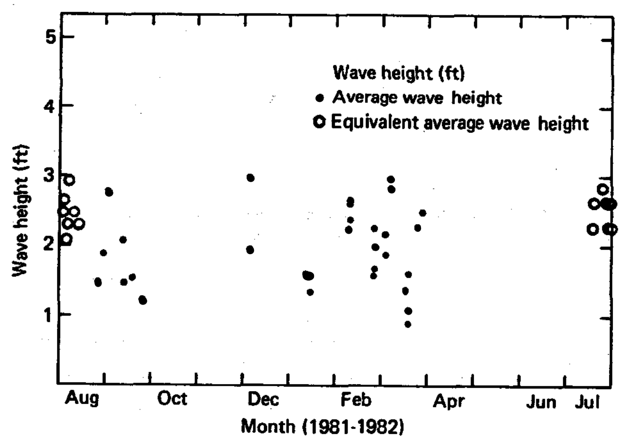

Fig. 3 Wave heights off Pt. Mugu. An equivalent average wave height was calculated from the total spectral energy using a technique discussed in Ref. 2. It is an upper bound for the average wave height, and the data are presented to supplement the average wave height data. (82-3/89)

as to predict power levels in the numerical model. In addition, a wave-tank model test of the combined hydrodynamics and thermodynamics of the PWEC capture chamber is planned to verify the numerical model and measure the chamber pressure. It will be conducted at the USNA facility by Prof. McCormick.

In conjunction with the program review and test planning, APL has reviewed the numerical model work performed by the Solar Energy Research Institute (SERI) and has developed a modified numerical model that couples the hydrodynamics of the water column with the thermodynamics of the capture chamber. For a given capture chamber design and external wave height, the APL model predicts power outputs that are only 30 to 50% as large as those predicted by the SERI model, which only considered an internal oscillating chamber water level (Table 1). For the capture chamber parameters presently proposed for the Pt. Mugu test where wave heights are in the 1 to 5 ft (0.3 to 1.5 m) range (Fig. 3), power outputs will be in the range of 3 to 30 kW (Table 2). The results of the modeling will be used to design the at-sea test and to estimate the cost to generate power on a commercial scale using multiple units of 125 to 500 kWe PWEC devices.

BACKGROUND AND DISCUSSION

The goal of the ocean energy program of DOE/DOET is to develop techniques for converting ocean energy to usable power on an economically attractive, commercial scale. The goals of the PWEC test program are to demonstrate that the device will convert wave energy to usable power and to determine its efficiency and reliability. Originally, the PWEC device was assembled by SERI for installation on the Japanese barge *Kaimei* as part of an International Energy Agency experiment. However, fabrication was not completed in time for the *Kaimei* test in 1980. SERI also performed a numerical analysis of the device that predicted output power as a function of capture chamber geometry and an internal oscillating water level. APL was subsequently directed by DOE to prepare the PWEC device for an at-sea test and to assess its commercial potential on a larger scale. The preparations included reviewing and expanding the numerical model, defining and initiating the necessary modifications required for an extended ocean platform test, and defining the required preliminary test of the major PWEC subsystems and assembly.

The selection of a site, preferably one with an existing platform, for the at-sea test and the rough estimation of costs for the construction and installation of the test hardware were the goals of the NCEL siting study. NCEL presented its findings at a meeting at NCEL on 12 August 1982. At the conclusion of the presentation, three possible sites had been identified, and the tower (Dixon's Tower) at the Pacific Missile Test Center, Point Mugu, was the preferred one (Ref. 2). Other possible locations are near the tower in Mission Bay near San Diego (which could only provide support functions) and one of the Santa Barbara Channel Islands. In the latter case, a cave that has an underwater opening to the sea would serve as the air capture chamber, and the PWEC base would be mounted on the ground above with a shaft or pipe connection to the cave. The site investigation was not exhaustive, given the time and budgetary constraints, and a number of further siting possibilities exist, all of which were judged not to be feasible at this time.

The cost estimate for conducting the test at the Pt. Mugu tower is in the range of several hundred thousand dollars; estimated costs for all other sites presently considered would be higher. The largest cost component of the offshore test is the structure required to support the PWEC system, including the air capture chamber. In addition to its lower cost, the Pt. Mugu tower is the most attractive because of its proximity to NCEL personnel for test monitoring and maintenance, the expressed interest and spirit of cooperation of the Pt. Mugu personnel, the small number and type of environmental restrictions, the existence of wave height data, and the relative ease of collecting additional data.

As part of the NCEL siting study, wave height data from the Santa Barbara Channel offshore of the Pt. Mugu site were collected (Fig. 3). Most of the waves are in the height (peak-to-trough) range of 1 to 5 ft (0.3 to 1.5 m). These data can be used to estimate the power expected at the Pt. Mugu site, as is discussed later.

In parallel with the NCEL siting study, APL reviewed and duplicated the SERI numerical model and developed a revised model based on the original SERI work. In particular, G. Dailey of APL investigated the calculated power differences between the sinusoidal interior wave of the SERI model and the equal external wave amplitudes in the revised model. The revised model (i.e., the hydrodynamically coupled model) replaces the sinusoidal displacement of the water surface in the chamber with a surface displacement that is calculated from the force balance for the water mass in the capture chamber.

The coupled equations for the force balance of the water with the thermodynamic equations govern the behavior of the air in the capture chamber; the results from this coupled dynamic model and the original SERI model are compared in Table 1 and Fig. 4. The figure shows the normalized variations of chamber pressure and chamber air volume during one cycle for the two models. Although both models predict similar phase relationships (Fig. 4), the coupled model predicts significantly lower amplitudes and power outputs than the uncoupled model, even for small wave heights (Table 1). The coupled model was used to predict average power outputs for various uniform wave systems and a cylindrical capture chamber geometry with dimensions appropriate to the Pt. Mugu tower (as shown in Fig. 1). The results are shown in Table 2.

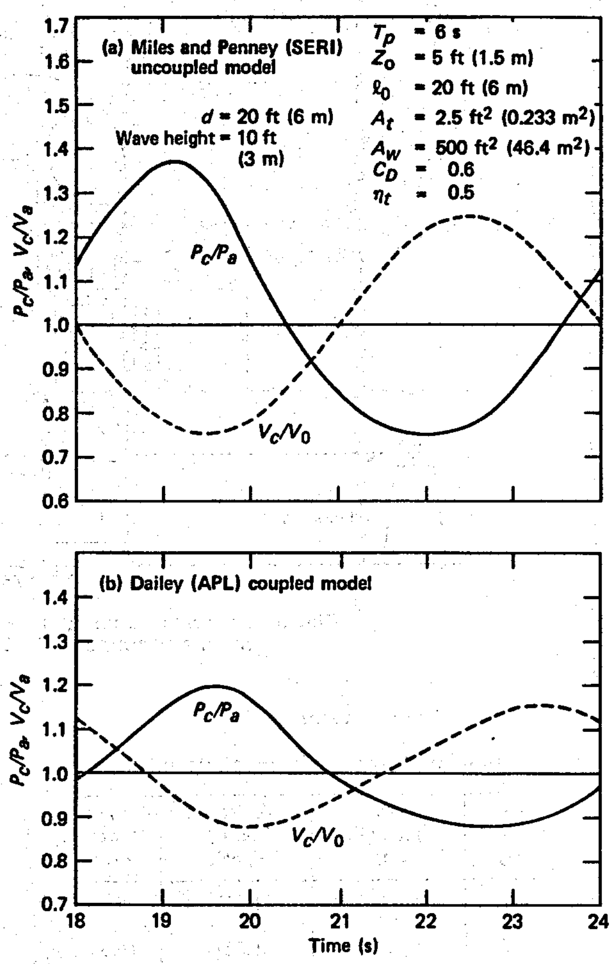

Fig. 4 Comparison of PWEC performance results from the SERI model and the APL coupled model. (82-3/90)

FUTURE PLANS

We have recommended to DOE/DOET that the performance characteristics of the air turbine in the PWEC device be measured in a closed-loop onshore test (Fig. 5; see Ref. 3 for details) and documented so that accurate model predictions can be made and the necessary control and safety system settings for the at-sea test can be determined. The primary test goal is to produce a turbine characteristics map similar to Fig. 2. The map shows a probable desired operating curve (dashed line) for the PWEC device. Since the wave resource determines the pressure difference across the chamber (Δp) (assuming a time averaged peak Δp oscillation), the dashed line determines the shaft rotation rate for maximum power output.

A secondary test goal is to verify operation of the existing instrumentation (see Table 2 of Ref. 4). The major features of the test are defined in Ref. 4; a schematic of the proposed test configuration is shown in Fig. 5. The test calls for mounting the turbine on a fixed stand and circulating air through it in a single direction. The test parameters include the pressure drop across the turbine, velocity, gearbox shaft rotation rate, and gearbox shaft power. NCEL is preparing a proposal for performing this test.

Following the turbine characteristics test, the resulting data, including air chamber model test data, will be used to determine detailed requirements for flywheel sizing, generator electric loading control, and the necessary limit and safety requirements noted previously. Given the variability of the waves, the prime operating control requirement is a time-averaged energy input measurement (torque-speed sensing) over a number of wave cycles, perhaps ten or more, to determine generator load increase or decrease. In addition to minimizing speed oscillation per wave to acceptable limits (two peaks per wave), the flywheel must be sized to absorb or supply energy to meet the anticipated change in energy content of succeeding waves and minimize the otherwise rapid generator load variation (or supply capability). Anticipatory control data in the form of far-field wave buoy measurements may also prove desirable.

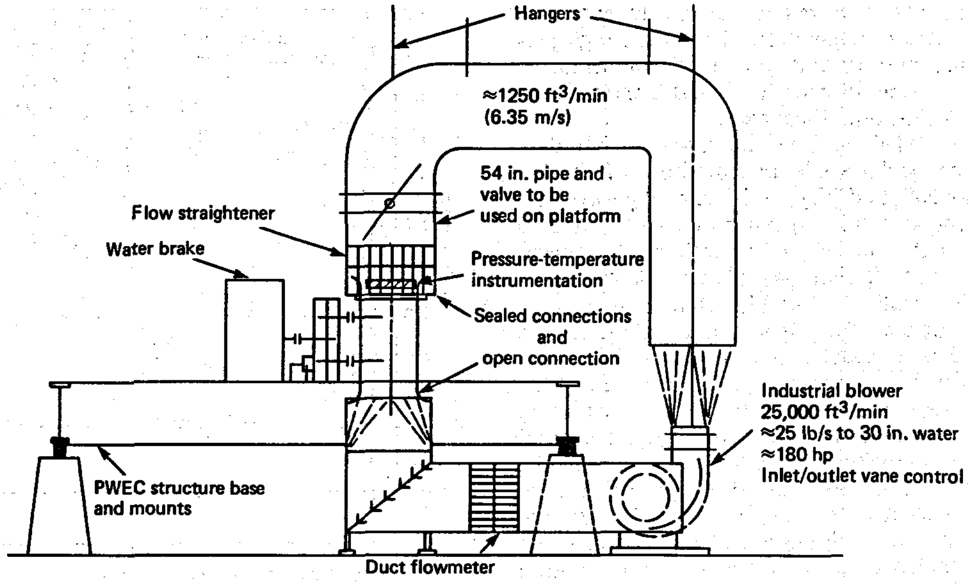

Fig. 5 Proposed configuration for onshore (dry) air turbine performance test. (82-3/91)

Table 2

Predicted power from coupled model.

Wave Period (s)	Wave Height in Feet (m)	Peak Pressure Ratio, P_c/P_a	Output Power (kW)
6	2 (0.61)	1.028	5.7
6	4 (1.22)	1.054	16.5
6	6 (1.83)	1.078	30.6
8	2 (0.61)	1.025	4.2
8	4 (1.22)	1.055	13.1
8	6 (1.83)	1.084	25.0
10	2 (0.61)	1.020	3.3
10	4 (1.22)	1.036	11.3
10	6 (1.83)	1.068	22.1

Capture chamber parameters:
D = 22.6 ft (6.9 m) d = 10 ft (3 m)
A_t = 1.829 ft^2 (0.17 m^2) C_D = 0.6
ℓ_0 = 18.5 ft (5.5 m) η_T = 0.6

A variable resistor bank load is under consideration for the presently proposed platform test, but site-dependent power utilization studies are necessary for the practical application of the output power. Actual site power utilization will require quantitative historical and seasonal wave data for power systems and structural-protection design. For the proposed Pt. Mugu installation, actual wave data will be transformed for use in the coupled model program, and the tower structure will be analyzed for the maximum design wave conditions.

A major element of the PWEC device is the air capture chamber and its support structure, as was discussed earlier. For the present evaluation, Prof. McCormick will perform a series of experiments in a wave tank at USNA to investigate the combined hydrodynamics and thermodynamics of the air capture chamber. The test plan (Ref. 5) calls for measurements of far-field wave height, chamber wave height, chamber pressure, and chamber exit velocity in a 3 ft (0.9 m) diameter chamber with various orifice (throat) sizes and an adjustable freeboard height of the order of 5 ft (1.5 m). The range of the independent test parameters was chosen to cover the range of wave heights (nondimensionalized by freeboard) that will be experienced at sea.

The numerical model will be modified to include the dynamics of the PWEC power train (i.e., turbine, gearbox, flywheel, and generator), and preparations will be made to incorporate the results of the turbine performance test. The model will be verified using results from the planned air chamber model tests at USNA (which are expected to be completed in January 1983) and other available data. The model will also be used in a parametric study of power production as a function of the major geometric and wave resource parameters. The results of the parametric study may be used in studies of possible alternate sites for an at-sea test and as a basis for a cost analysis of PWEC power production, to be done by Gibbs & Cox, Inc. under contract to APL. Gibbs and Cox have previously completed comprehensive wave energy device analyses for DOE, and their cost study will address commercial scale PWEC power production at a few selected sites. The study will identify all costs associated with the manufacture, installation, operation, and maintenance of PWEC power systems for commerical applications of 125, 250, and 500 MWe units.

NOMENCLATURE

A_t	Turbine throat area
A_w	Cross-sectional area of chamber
C_D	Turbine discharge coefficient
D	Chamber diameter
d	Draft
ℓ_0	Freeboard
P_a	Atmospheric pressure
P_c	Chamber pressure
T_p	Time period
V_a	$\ell_0 \times A_w$, i.e., quiescent chamber air volume
V_0	$d \times A_w$, i.e., quiescent chamber water volume
V_c	Chamber water volume
Z_o	Far-field wave height, single amplitude
Δp	Pressure difference across turbine
η_t	Turbine efficiency

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